

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 sources of emissions discussed in this report and a review of the methodology used to identify those key sources. Annex 2 describes the methodologies used to estimate CO₂ emissions from fossil fuel combustion, the carbon content of fossil fuels, and the amount of carbon stored in products from non-energy uses of fossil fuels. Annex 3 discusses the methodologies used for a number of individual source categories in greater detail than was presented in the main body of the report and includes explicit activity data and emission factor tables. Annex 4 presents the IPCC reference approach for estimating CO₂ emissions from fossil fuel combustion. Annex 5 addresses the criteria for the inclusion of an emission source category and discusses some of the sources that are excluded from U.S. estimates. Annex 6 provides a range of additional information that is relevant to the contents of this report. Finally, Annex 7 provides data on the uncertainty of the emission estimates included in this report.

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ANNEX 1 Key Source Analysis

The United States provides an analysis of key sources of emissions found in this report in order to ensure accuracy and reliability of inventory estimates. The IPCC's *Good Practice Guidance* (IPCC 2000) defines a key source category as a "[source 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 source categories are sources that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key source categories must also account for the influence of trends of individual source categories. Therefore, a trend assessment is conducted to identify source categories for which significant uncertainty in the estimate would have considerable effects on overall emission trends. This analysis culls out source categories that diverge from the overall trend in national emissions. Finally, a qualitative evaluation of key source categories should be performed, in order to capture any key source categories that were not identified in either of the quantitative analyses.

The methodology for conducting a key source analysis, as defined by IPCC's *Good Practice Guidance* (IPCC 2000), 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 source categories; discusses Tier 1, Tier 2, and qualitative approaches to identifying key sources; provides level and trend assessment equations; and provides a brief statistical evaluation of IPCC's quantitative methodologies for defining key sources.

Table 1-1 presents the key source categories for the United States using emissions data in this report, and ranked according to their sector and global warming potential-weighted emissions in 2003. The table also identifies the criteria used in identifying these source categories (i.e., level, trend, and/or qualitative assessments).

Table 1-1: Key Source Categories for the United States (1990-2003) Based on Tier 1 Approach

IPCC Source Categories	Gas	Level	Trend	Qual ^a	2003 Emissions (Tg CO ₂ Eq.)
Energy					
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	✓	✓		2,013.8
Mobile Combustion: Road & Other	CO ₂	✓	✓		1,538.5
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	✓	✓		1,134.9
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	✓	✓		635.3
Mobile Combustion: Aviation	CO ₂	✓	✓		171.3
Fugitive Emissions from Natural Gas Operations	CH ₄	✓	✓		125.9
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	✓			118.0
International Bunker Fuels ^b	Several			✓	85.1
Mobile Combustion: Marine	CO ₂	✓			57.5
Fugitive Emissions from Coal Mining and Handling	CH ₄	✓	✓		53.8
Mobile Combustion: Road & Other	N ₂ O	✓	✓		39.9
Fugitive Emissions from Oil Operations	CH ₄		✓		17.1
Industrial Processes					
Emissions from Substitutes for Ozone Depleting Substances	Several	✓	✓		99.5

¹ See chapter 7 "Methodological Choice and Recalculation" in IPCC (2000).
< <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>>

CO ₂ Emissions from Iron and Steel Production	CO ₂	✓	✓	53.8
CO ₂ Emissions from Cement Production	CO ₂	✓	✓	43.0
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂		✓	15.6
SF ₆ Emissions from Electrical Equipment	SF ₆		✓	14.1
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	✓	✓	12.3
N ₂ O Emissions from Adipic Acid Production	N ₂ O		✓	6.0
PFC Emissions from Aluminum Production	PFCs		✓	3.8
Agriculture				
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	✓		155.3
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	✓	✓	115.0
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	✓	✓	98.2
CH ₄ Emissions from Manure Management	CH ₄	✓		39.1
Waste				
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	✓	✓	131.2
CH ₄ Emissions from Wastewater Handling	CH ₄	✓	✓	36.8
CO ₂ Emissions from Waste Incineration	CO ₂		✓	18.8
Subtotal				6,833.5
Total Emissions				6,900.2
Percent of Total				99.0%

^aQualitative criteria.

^bEmissions from this source not included in totals.

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Note: The Tier 1 approach for identifying key source categories does not directly include assessment of uncertainty in emissions estimates.

Table 1-2 provides a complete listing of source categories by IPCC sector, along with comments on the criteria used in identifying key source categories. The comments refer specifically to the year(s) over the course of the entire inventory time series (i.e., 1990 to 2003) in which each source category reached the threshold for being a key source based on a Tier 1 level assessment. The following points should be noted regarding the key sources identified.

Due to the relative quantity of CO₂ emissions from fossil fuel combustion—particularly from mobile combustion in road vehicles and stationary combustion of coal, gas, and oil—these sources contributed most to each year's level assessment. Additionally, the following sources were identified as key sources based on the level assessments for each year (listed in descending order of their 2003 emissions):

- CO₂ emissions from mobile combustion in the aviation sector;
- Direct N₂O from agricultural soils;
- CH₄ from solid waste disposal sites;
- Fugitive emissions from natural gas operations;
- CO₂ from non-energy use of fuel;
- CH₄ from enteric fermentation in domestic livestock;
- Indirect N₂O emissions from nitrogen used in agriculture;
- Fugitive emissions from coal mining;
- CO₂ emissions from iron and steel production;
- CO₂ emissions from cement production; and
- N₂O emissions from mobile combustion in road vehicles.

The remaining key sources identified under the level assessment varied by year. The following five source categories were determined to be key sources using the level assessment for only part of the complete time series (listed in descending order of their 2003 emissions):

- HFC and PFC emissions from substitutes for ozone depleting substances (1996-2003);
- CO₂ emissions from mobile combustion in the marine sector (1990-1997, 1999-2003);
- CH₄ emissions from manure management (1990-2000);
- CH₄ emissions from wastewater handling (1995 and 1997); and
- HFC-23 emissions from HCFC-22 manufacture (1990-1996, 1998).

Although other sources have fluctuated by greater percentages since 1990, by virtue of their size, CO₂ emissions from mobile combustion from road vehicles and stationary combustion of coal are the greatest contributors to the overall trend for 2003. The third largest contributor to the overall trend in 2003 is emissions from substitutes for ozone depleting substances (ODSs). These emissions have grown quickly with the phase out of ODSs under the Montreal Protocol.

Two additional source categories with trends of note are fugitive emissions from coal mining and PFC emissions from aluminum manufacturing, which decreased from 1990 through 2003 by approximately 34 and 79 percent, respectively. Reductions in emissions from coal mining are primarily due to EPA's voluntary coalbed methane capture program and the mining of less gassy coal than in previous years. PFC emissions have decreased primarily as a result of emission reduction activities by the aluminum industry.

The remaining source categories that were identified as key sources based solely on a trend assessment are listed below (listed in descending order of their 2003 emissions).

- CO₂ emissions from waste incineration;
- Fugitive emissions from oil operations;
- CO₂ emissions from ammonia production and urea application;
- SF₆ emissions from electrical equipment; and
- N₂O emissions from adipic acid production.

In addition to conducting Tier 1 level and trend assessments, a qualitative assessment of the source categories, as described in the IPCC's *Good Practice Guidance* (IPCC 2000), was conducted to capture any key sources that were not identified by either quantitative method. One additional key source was identified using this qualitative assessment. A brief discussion of the reasoning for the qualitative designation is provided below.

- 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 source 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 1-3 through Table 1-16 contain each individual year's level assessment and contain further detail on where each source falls within the analysis. Table 1-17 details the trend assessment for 1990 through 2003.

Table 1-2: U.S Greenhouse Gas Inventory Source Categories Based on Tier 1 Approach

IPCC Source Categories	Direct GHG	2003 Emissions (Tg CO ₂ Eq.)	Key Source		Comments
			Category	ID	
			Flag?	Criteria	
Energy					
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	2,013.8	✓	L, T	All years
Mobile Combustion: Road & Other	CO ₂	1,538.5	✓	L, T	All years
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	1,134.9	✓	L, T	All years

CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	635.3	✓	L, T	All years
Mobile Combustion: Aviation	CO ₂	171.3	✓	L, T	All years
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	118.0	✓	L	All years
Mobile Combustion: Marine	CO ₂	57.5	✓	L	Level in 1990 - 1997, 1999 - 2003
CO ₂ Emissions from Natural Gas Flaring	CO ₂	6.0			
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.3			
Fugitive Emissions from Natural Gas Operations	CH ₄	125.9	✓	L, T	All years
Fugitive Emissions from Coal Mining and Handling	CH ₄	53.8	✓	L, T	All years
Fugitive Emissions from Oil Operations	CH ₄	17.1	✓	T	
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	6.7			
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.4			
Mobile Combustion: Road & Other	CH ₄	2.5			
Mobile Combustion: Aviation	CH ₄	0.1			
Mobile Combustion: Marine	CH ₄	0.1			
Mobile Combustion: Road & Other	N ₂ O	39.9	✓	L, T	All years
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	13.8			
Mobile Combustion: Aviation	N ₂ O	1.7			
Mobile Combustion: Marine	N ₂ O	0.5			
International Bunker Fuels ^a	Several	85.1	✓	Q	
Industrial Processes					
CO ₂ Emissions from Iron and Steel Production	CO ₂	53.8	✓	L, T	All years
CO ₂ Emissions from Cement Production	CO ₂	43.0	✓	L, T	All years
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	15.6	✓	T	
CO ₂ Emissions from Lime Production	CO ₂	13.0			
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	4.7			
CO ₂ Emissions from Aluminum Production	CO ₂	4.2			
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.1			
CO ₂ Emissions from Petrochemical Production	CO ₂	2.8			
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	2.0			
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.4			
CO ₂ Emissions from Ferroalloys	CO ₂	1.4			
CO ₂ Emissions from CO ₂ Consumption	CO ₂	1.3			
CH ₄ Emissions from Petrochemical Production	CH ₄	1.5			
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.0			
CH ₄ Emissions from Silicon Carbide Production	CH ₄	+			
N ₂ O Emissions from Nitric Acid Production	N ₂ O	15.8			
N ₂ O Emissions from Adipic Acid Production	N ₂ O	6.0	✓	T	
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.8			
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	99.5	✓	L, T	Level in 1996 - 2003
SF ₆ Emissions from Electrical Equipment	HiGWP	14.1	✓	T	
HFC-23 Emissions from HCFC-22 Manufacture	HiGWP	12.3	✓	L, T	Level in 1990 - 1996, 1998
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	HiGWP	4.3			
PFC Emissions from Aluminum Production	HiGWP	3.8	✓	T	
SF ₆ Emissions from Magnesium Production	HiGWP	3.0			
Agriculture					
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	115.0	✓	L, T	All years
CH ₄ Emissions from Manure Management	CH ₄	39.1	✓	L	Level in 1990 - 2000
CH ₄ Emissions from Rice Production	CH ₄	6.9			
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.8			
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	155.3	✓	L	All years
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	98.2	✓	L, T	All years

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N ₂ O Emissions from Manure Management	N ₂ O	17.5			
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.4			
Waste					
CO ₂ Emissions from Waste Incineration	CO ₂	18.8	✓	T	
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	131.2	✓	L, T	All years
CH ₄ Emissions from Wastewater Handling	CH ₄	36.8	✓	L, T	Level in 1995, 1997
N ₂ O Emissions from Wastewater Handling	N ₂ O	15.9			
N ₂ O Emissions from Waste Incineration	N ₂ O	0.5			
Land-use Change and Forestry					
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	6.0			
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.4			

^a Emissions from these sources not included in totals.

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Note: The Tier 1 approach for identifying key source categories does not directly include assessment of uncertainty in emissions estimates.

Tier 1 Approach

The Tier 1 method for identifying key source categories assesses the impacts of all IPCC-defined source categories on the level and trend of the national emission inventory for the 1990 through 2003 time-series, but works independently of any formal uncertainty analysis. Although conducting a Tier 1 key source analysis is very valuable in improving the U.S. inventory, it would be ideal to incorporate the results of an uncertainty analysis into the key source analysis in order to be able to take into account the level of uncertainty associated with each estimate. Although quantitative uncertainty analyses have been conducted for almost every U.S. emission source, an assessment of the uncertainty of all source categories is required before uncertainties can be taken into account for the key source analysis. See the description of the Tier 2 approach for further explanation.

When using a Tier 1 approach for the *level*, a predetermined cumulative emissions threshold is used to identify key source categories. When source categories are sorted in order of decreasing emissions, those that fall at the top of the list and cumulatively account for 95 percent of emissions are considered key source categories. The 95 percent threshold was established based on an evaluation of several inventories, and was designed to establish a general level where the key source category analysis covers approximately 75 to 92 percent of inventory uncertainty. The Tier 1 approach for the *trend* uses a 95 percent contribution threshold of the cumulative contribution to the trend assessment metric, which was also designed to establish a general level where the key source category analysis covers 90 percent of inventory uncertainty. The Tier 1 method is completed using a simple spreadsheet analysis based on equations for both level and trend assessments that are described in detail below. It is the current approach that the United States is taking to identify key source categories of greenhouse gas emissions until a rigorous uncertainty analysis is completed.

Tier 2 Approach

IPCC recommends that inventory agencies use the 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. Using the Tier 2 approach, key source categories represent 90 percent of the uncertainty in the national inventory, as opposed to those that sum to the pre-determined cumulative emissions or trend threshold. A simple spreadsheet version accounts for the uncertainty contribution by applying the source category percentage uncertainty estimates to the Tier 1 level and trend assessments.

The U.S. EPA is in the process of developing a robust plan to support data gathering for both a Tier 1 and/or a Monte Carlo level analysis. Where a Monte Carlo approach to uncertainty analysis has been undertaken, uncertainty estimates for each source category have been developed based on (a) source category-specific input variables, such as activity data and emission factors, (b) the statistical properties underlying the input variables (i.e., the characteristics of the probability distributions of the input variables, such as mean and standard deviation in the case of a normal distribution), and (c) the mathematical relationship between the input variables used to estimate the emissions for each source category (e.g., emissions = activity data * emission factor). As part of a multi-year effort, the United States has already developed quantitative uncertainty estimates for most source categories. However,

because quantitative estimates of uncertainty are not yet available for all source categories, it is premature to conduct a Tier 2 key source analysis at this point. Future inventories will incorporate this Tier 2 approach.

Qualitative Approach

In addition to conducting a quantitative assessment like the ones described above, a variety of qualitative criteria could be applied to identify additional key source categories. The following qualitative criteria for identifying key source categories have been outlined in the *Good Practice Guidance* (IPCC 2000). A source category should be identified as a key source if:

- Mitigation techniques and technologies are being implemented to reduce emissions from the source category that are expected to be reflected in the inventory estimates;
- Significant changes in emissions (i.e., growth or decline) from the source category is expected in the future;
- High uncertainty is evident for the source category; or
- Unexpectedly low or high emissions, or other order of magnitude discrepancies, are apparent for the source category.

In many cases, the results of this qualitative approach to identifying key source categories will overlap with source categories already defined as key source categories through the quantitative analysis. However, the qualitative method may illuminate a few additional key source categories, which should then be included in the final list of key source categories. However, the application of such qualitative criteria are primarily intended to identify any additional source categories that were “just under” the threshold criteria for the level assessment and not for extremely minor source categories. International bunker fuels is the only source category that is considered key from a qualitative standpoint. International bunker fuel emissions are not included in national totals, and are not considered in the level or trend analyses mentioned above, but are considered key from a qualitative standpoint due to their unique position within the emissions accounting framework.

Level and Trend Assessments of Key Source Categories

Level Assessment

A level assessment was performed for years 1990 to 2003. Key sources were identified as the source categories that cumulatively add up to 95 percent of the total emissions for a given year when the source categories are summed, in descending order of magnitude for that year. All source categories that met this threshold for at least one year were considered key sources. Level estimates are based upon the following equation:

$$\text{Source Category Level Assessment} = \text{Source Category} / \text{Total Estimate}$$

$$L_{x,t} = E_{x,t} / E_t$$

Where:

$L_{x,t}$ = level assessment for source x in year t
 $E_{x,t}$ = emissions estimate for source x in year t
 E_t = total emissions estimate for year t

Trend Assessment

A trend assessment was then conducted to evaluate how significantly the difference between the source category’s trend and the overall inventory trend affect the overall trend. This assessment was done by multiplying the difference between the source category trend and the total inventory trend by the source category level assessment. Trend assessments were based upon the following equation:

$$\text{Source Category Trend Assessment} = (\text{Source Category Level Assessment}) \times \left| \frac{\text{Source Category Trend} - \text{Total Trend}}{\text{Total Trend}} \right|$$

$$T_{x,t} = L_{x,t} \times \left| \left[\frac{(E_{x,t} - E_{x,o})}{E_{x,t}} - \frac{(E_t - E_o)}{E_t} \right] \right|$$

Where:

$T_{x,t}$ = trend assessment for source x in year t
 $L_{x,t}$ = level assessment for source x in year t
 $E_{x,t}$ and $E_{x,0}$ = emissions estimates for source x in year t and year 0, respectively
 E_t and E_0 = total emissions estimate for year t and year 0, respectively
0 = base year (e.g., 1990)

The following section of this annex evaluates these key source category analyses. The remainder of the annex summarizes the key source categories identified by these analyses, and quantifies their contribution to total level and trend assessments.

Evaluation of Key Source Identification Methodologies

Level Assessment

The Tier 1 approach for level assessment defines the source category contribution as the percentage of total inventory emissions from that source category. Only emission source categories are considered.² To determine key source categories, the level assessments are sorted in decreasing order, so that the source categories with the highest level assessments appear first. The level assessments are summed until the threshold of 95 percent is reached; all source categories that fall within that cumulative 95 percent for at least one year are considered key source categories.

Since the Tier 1 approach does not explicitly incorporate uncertainties, the level assessment key source categories will be the largest contributors to total emissions but will not necessarily have large contributions to the total uncertainty. Focusing resources on improving the methodologies for estimating emissions from the source categories with the largest emissions is undesirable if those emissions are estimated relatively precisely using the current methodologies. Nevertheless, the analysis (reported in IPCC 2000) of several inventories that have source category uncertainties showed that about 75 to 92 percent of the total uncertainty could be covered by the source categories in the top 95 percent of emissions.

It is important to note that this key source category analysis can be very sensitive to the definitions of the source 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. A consistent approach to addressing this issue is available in the *Good Practice Guidance*. Table 7.1 in IPCC (2000) provides guidance and a suggested list of source categories for analysis, although countries are given some discretion based upon their national circumstances.

Some important components of other source categories were not included in the list of IPCC source categories in the key source category chapter of IPCC's *Good Practice Guidance* (IPCC 2000). These source categories include fossil fuel feedstocks, international bunkers, and emissions from U.S. territories. They are potentially large source categories that often are derived from unique data sources using country-specific methodologies, and may have a significant impact on the uncertainty of the estimates.

Trend Assessment

The Tier 1 approach for trend assessment is defined as the product of the source category level assessment (i.e., source category emissions as a fraction, or percentage, of total emissions) and the absolute difference between the source category trend and the total trend. In turn, the source category trend is defined as the change in source category emissions from the base year to the current year, as a percentage of current year emissions from that source category. The total trend is the percentage change in total inventory emissions from the base year to the current year. Thus, the *source category trend assessment* will be large if the source category represents a large percentage of emissions and/or has a trend that is quite different from the overall inventory trend. Only emissions source

² The level assessment is intended to be applied to sources and to exclude sinks. Although the assessment would still be valid if sinks were included (as unsigned values), the 95 percent threshold by which sources are deemed "key" would lose significance because it is based on an analysis (Flusgrud et al. 1999) of selected inventories where sinks were excluded.

categories are considered.³ To determine key source categories, the trend assessments are sorted in decreasing order, so that the source categories with the highest trend assessments appear first. The trend assessments are summed until the threshold of 95 percent is reached; all source categories that fall within that cumulative 95 percent are considered key source categories.

It is important to note that the trend assessment calculation assumes that the base and current year source category emission uncertainties are the same. Therefore, the trend assessment is a useful measure in cases where the percentage uncertainties of the base and current year source category emission levels are thought to be the same. However, its usefulness diminishes when individual source category uncertainties are different between the base year and the current year. Such time series inconsistencies could result from changes in data quality or availability over time. As more rigorous methods to determine uncertainties in emission estimates are applied, it may be necessary to revisit the results of the trend assessments.

Another important caveat to the identification of key source categories through the trend assessment is that, while each individual source category's trend assessment provides a measure of how sensitive the overall trend in the inventory is to the trend of a particular source category, the sum of a number of trend assessments does not yield the total sensitivity of the overall trend to changes in all of those source categories. In other words, the cumulative percentages should not be considered a measure of the percentage contributions to the trend from those source categories.

The trend assessment key source categories are also sensitive to the level of aggregation of the source categories; and the IPCC list of source categories may exclude some important, potentially key source category components.

³ The trend assessment is intended to be applied to sources and to exclude sinks. Although the assessment would still be valid if sinks were included (as unsigned values), the 95 percent threshold by which sources are deemed "key" would lose significance because it is based on an analysis (Flusgrud et al. 1999) of selected inventories where sinks were excluded.

Table 1-3: 1990 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct		1990 Estimate (Tg CO ₂ Eq.)	1990 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
	Greenhouse Gas					
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂		1,680.89	1,680.89	0.28	0.28
Mobile Combustion: Road & Other	CO ₂		1,220.43	1,220.43	0.20	0.48
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂		973.63	973.63	0.16	0.64
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂		609.99	609.99	0.10	0.74
Mobile Combustion: Aviation	CO ₂		177.24	177.24	0.03	0.77
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄		172.23	172.23	0.03	0.79
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O		140.36	140.36	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄		128.35	128.35	0.02	0.84
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄		117.86	117.86	0.02	0.86
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O		112.63	112.63	0.02	0.88
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂		107.96	107.96	0.02	0.89
CO ₂ Emissions from Iron and Steel Production	CO ₂		85.41	85.41	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH ₄		81.89	81.89	0.01	0.92
Mobile Combustion: Marine	CO ₂		49.17	49.17	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O		41.62	41.62	0.01	0.94
HFC-23 Emissions from HCFC-22 Manufacture	HFCs		34.98	34.98	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂		33.28	33.28	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄		31.19	31.19	0.01	0.95
SF ₆ Emissions from Electrical Equipment	SF ₆		29.22	29.22	<0.01	0.96
CH ₄ Emissions from Wastewater Handling	CH ₄		24.85	24.85	<0.01	0.96
Fugitive Emissions from Oil Operations	CH ₄		19.97	19.97	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂		19.31	19.31	<0.01	0.97
PFC Emissions from Aluminum Production	PFCs		18.34	18.34	<0.01	0.97
N ₂ O Emissions from Nitric Acid Production	N ₂ O		17.85	17.85	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O		16.26	16.26	<0.01	0.98
N ₂ O Emissions from Adipic Acid Production	N ₂ O		15.20	15.20	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O		13.02	13.02	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O		12.26	12.26	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂		11.24	11.24	<0.01	0.98
CO ₂ Emissions from Waste Incineration	CO ₂		10.92	10.92	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄		7.84	7.84	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄		7.12	7.12	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂		6.31	6.31	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄		6.06	6.06	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂		5.81	5.81	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O		5.54	5.54	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂		5.53	5.53	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆		5.37	5.37	<0.01	0.99
Mobile Combustion: Road & Other	CH ₄		4.55	4.55	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O		4.30	4.30	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂		4.14	4.14	<0.01	1.00
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆		2.91	2.91	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₂		2.22	2.22	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂		1.98	1.98	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O		1.72	1.72	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂		1.53	1.53	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄		1.32	1.32	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂		1.31	1.31	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄		1.17	1.17	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂		0.86	0.86	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄		0.69	0.69	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O		0.42	0.42	<0.01	1.00
Emissions from Substitutes for Ozone Depleting Substances	Several		0.40	0.40	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂		0.40	0.40	<0.01	1.00
Mobile Combustion: Marine	N ₂ O		0.39	0.39	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O		0.37	0.37	<0.01	1.00
Mobile Combustion: Aviation	CH ₄		0.16	0.16	<0.01	1.00
Mobile Combustion: Marine	CH ₄		0.08	0.08	<0.01	1.00

N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.06	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.03	<0.01	1.00
TOTAL		6,088.11	6,088.11	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-4: 1991 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct	1990 Estimate (Tg CO ₂ Eq.)	1991 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
	Greenhouse Gas				
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,677.65	0.28	0.28
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,208.03	0.20	0.48
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	998.36	0.17	0.64
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	583.53	0.10	0.74
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	172.75	0.03	0.77
Mobile Combustion: Aviation	CO ₂	177.24	169.37	0.03	0.80
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	143.49	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	130.00	0.02	0.84
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	117.11	0.02	0.86
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	108.29	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	104.08	0.02	0.90
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	79.04	0.01	0.91
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	76.24	0.01	0.92
Mobile Combustion: Road & Other	N ₂ O	41.62	44.05	0.01	0.93
Mobile Combustion: Marine	CO ₂	49.17	43.75	0.01	0.94
CH ₄ Emissions from Manure Management	CH ₄	31.19	33.13	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	32.54	0.01	0.95
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	30.77	0.01	0.95
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	27.84	<0.01	0.96
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	25.78	<0.01	0.96
Fugitive Emissions from Oil Operations	CH ₄	19.97	20.24	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	19.17	<0.01	0.97
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	17.83	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	16.76	<0.01	0.97
PFC Emissions from Aluminum Production	PFCs	18.34	15.51	<0.01	0.98
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	14.84	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	13.37	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	12.18	<0.01	0.98
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	11.97	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	11.01	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	8.01	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.00	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	6.43	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	6.21	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	5.87	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	5.63	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	5.11	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	4.98	<0.01	0.99
Mobile Combustion: Road & Other	CH ₄	4.55	4.50	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.18	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.04	<0.01	1.00
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	2.91	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.28	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.77	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.64	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.40	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.33	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.22	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.17	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.86	<0.01	1.00
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	0.75	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.65	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.41	<0.01	1.00

N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.36	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.35	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.35	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.07	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.06	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,038.39	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-5: 1992 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)	1992 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,693.10	0.28	0.28
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,227.95	0.20	0.48
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,035.80	0.17	0.65
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	595.03	0.10	0.74
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	172.64	0.03	0.77
Mobile Combustion: Aviation	CO ₂	177.24	167.15	0.03	0.80
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	138.73	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	129.70	0.02	0.84
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	119.40	0.02	0.86
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	104.87	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	94.50	0.02	0.90
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	77.05	0.01	0.91
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	75.01	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	57.20	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O	41.62	46.86	0.01	0.94
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	34.87	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	32.79	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄	31.19	32.04	0.01	0.95
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	26.92	<0.01	0.96
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	25.19	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	19.99	<0.01	0.96
Fugitive Emissions from Oil Operations	CH ₄	19.97	19.58	<0.01	0.97
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	18.30	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	16.54	<0.01	0.97
PFC Emissions from Aluminum Production	PFCs	18.34	14.28	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	13.57	<0.01	0.98
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	13.05	<0.01	0.98
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	12.68	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	12.42	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	11.39	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	8.33	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.87	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	6.63	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	6.31	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	5.67	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	5.40	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	5.31	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	4.92	<0.01	0.99
Mobile Combustion: Road & Other	CH ₄	4.55	4.45	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.07	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	3.94	<0.01	1.00
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	2.91	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.42	<0.01	1.00
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	2.11	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.79	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.62	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.52	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.51	<0.01	1.00

CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.27	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.23	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.79	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.76	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.46	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.43	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.41	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.40	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.09	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.09	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,121.48	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-6: 1993 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)	1993 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,761.31	0.28	0.28
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,260.08	0.20	0.48
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,060.84	0.17	0.65
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	587.08	0.09	0.75
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	172.10	0.03	0.77
Mobile Combustion: Aviation	CO ₂	177.24	168.11	0.03	0.80
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	145.66	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	133.22	0.02	0.85
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	118.83	0.02	0.87
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	105.80	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	101.92	0.02	0.90
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	69.86	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	65.16	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	54.18	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O	41.62	49.07	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	34.62	0.01	0.94
CH ₄ Emissions from Manure Management	CH ₄	31.19	32.80	0.01	0.95
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	31.82	0.01	0.95
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	29.50	<0.01	0.96
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	27.66	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	20.41	<0.01	0.96
Fugitive Emissions from Oil Operations	CH ₄	19.97	19.14	<0.01	0.97
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	18.57	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	16.97	<0.01	0.97
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	13.99	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	13.78	<0.01	0.98
PFC Emissions from Aluminum Production	PFCs	18.34	13.69	<0.01	0.98
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	13.53	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	12.63	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	11.64	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	7.82	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.02	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	7.00	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	6.79	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	5.88	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.76	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	5.51	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	4.94	<0.01	0.99
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	4.78	<0.01	0.99
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.48	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	4.42	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.02	<0.01	1.00
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	3.64	<0.01	1.00

CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.57	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.74	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.63	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.55	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.39	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.30	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.25	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.82	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.61	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.44	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.40	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.38	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.34	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.14	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.11	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.08	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,250.82	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-7: 1994 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct	1990 Estimate (Tg CO ₂ Eq.)	1994 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
	Greenhouse Gas				
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,770.44	0.28	0.28
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,294.94	0.20	0.48
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,079.18	0.17	0.65
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	588.73	0.09	0.75
Mobile Combustion: Aviation	CO ₂	177.24	176.13	0.03	0.77
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	169.09	0.03	0.80
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	151.06	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	133.94	0.02	0.85
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	120.40	0.02	0.86
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	117.75	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	87.29	0.01	0.90
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	73.61	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	65.15	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	53.39	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O	41.62	50.48	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	36.09	0.01	0.94
CH ₄ Emissions from Manure Management	CH ₄	31.19	35.31	0.01	0.95
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	31.59	<0.01	0.95
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	28.87	<0.01	0.96
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	26.82	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	21.10	<0.01	0.96
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	19.60	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	18.93	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	16.97	<0.01	0.97
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	15.03	<0.01	0.97
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	14.29	<0.01	0.98
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	14.19	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	12.80	<0.01	0.98
PFC Emissions from Aluminum Production	PFCs	18.34	12.06	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	12.05	<0.01	0.98
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	9.80	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	8.29	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	8.21	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	7.81	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	6.86	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.12	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	5.51	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	5.38	<0.01	0.99

CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.15	<0.01	0.99
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.48	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	4.29	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.02	<0.01	1.00
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	4.00	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.69	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.85	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.71	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.67	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.52	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.50	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.27	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.83	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.81	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.46	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.43	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.40	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.34	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.13	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.08	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,343.06	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-8: 1995 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)	1995 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,786.67	0.28	0.28
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,324.43	0.21	0.49
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,128.30	0.18	0.66
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	542.39	0.08	0.75
Mobile Combustion: Aviation	CO ₂	177.24	171.82	0.03	0.77
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	162.40	0.03	0.80
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	146.55	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	133.33	0.02	0.84
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	122.97	0.02	0.86
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	115.50	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	98.17	0.02	0.89
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	74.36	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	65.78	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	55.19	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O	41.62	51.63	0.01	0.93
CO ₂ Emissions from Cement Production	CO ₂	33.28	36.85	0.01	0.94
CH ₄ Emissions from Manure Management	CH ₄	31.19	36.07	0.01	0.94
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	29.89	<0.01	0.95
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	27.03	<0.01	0.95
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	24.45	<0.01	0.96
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	21.67	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	20.45	<0.01	0.96
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	19.88	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	18.75	<0.01	0.97
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	17.21	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.13	<0.01	0.98
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	15.74	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	14.22	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	12.90	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	12.80	<0.01	0.98
PFC Emissions from Aluminum Production	PFCs	18.34	11.83	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	8.99	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	8.41	<0.01	0.99

Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	8.18	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.62	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	7.36	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	5.92	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	5.57	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.27	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	4.95	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.48	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.30	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	4.17	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.75	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.87	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.67	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.67	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.53	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.51	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.31	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.80	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.66	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.44	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.40	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.38	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.37	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.19	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.09	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,407.36	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-9: 1996 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)	1996 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,872.64	0.28	0.28
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,360.36	0.21	0.49
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,148.57	0.17	0.66
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	579.45	0.09	0.75
Mobile Combustion: Aviation	CO ₂	177.24	180.13	0.03	0.78
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	158.94	0.02	0.80
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	155.62	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	134.53	0.02	0.84
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	120.52	0.02	0.86
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	114.01	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	108.39	0.02	0.90
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	68.32	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	63.16	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	53.39	0.01	0.92
Mobile Combustion: Road & Other	N ₂ O	41.62	52.39	0.01	0.93
CO ₂ Emissions from Cement Production	CO ₂	33.28	37.08	0.01	0.94
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	35.12	0.01	0.94
CH ₄ Emissions from Manure Management	CH ₄	31.19	34.72	0.01	0.95
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	31.12	<0.01	0.95
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	30.71	<0.01	0.96
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	24.25	<0.01	0.96
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	20.71	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	20.28	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	18.74	<0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	17.19	<0.01	0.97
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	17.04	<0.01	0.98
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.03	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	14.41	<0.01	0.98

CO ₂ Emissions from Lime Production	CO ₂	11.24	13.49	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.46	<0.01	0.98
PFC Emissions from Aluminum Production	PFCs	18.34	12.47	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	8.63	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	8.53	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	8.35	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	7.82	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	6.97	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	6.53	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.12	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.58	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	5.50	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.48	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.24	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	4.01	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.78	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.95	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.75	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.66	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.60	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.55	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.27	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.76	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.75	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.43	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.42	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.41	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.38	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.24	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.08	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,621.20	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-10: 1997 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)	1997 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,920.24	0.29	0.29
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,385.64	0.21	0.50
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,152.53	0.17	0.67
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	586.69	0.09	0.76
Mobile Combustion: Aviation	CO ₂	177.24	178.96	0.03	0.78
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	155.86	0.02	0.81
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	147.35	0.02	0.83
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	133.63	0.02	0.85
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	120.30	0.02	0.87
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	118.32	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	96.17	0.01	0.90
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	71.86	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	62.64	0.01	0.92
Mobile Combustion: Road & Other	N ₂ O	41.62	53.12	0.01	0.93
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	46.47	0.01	0.93
Mobile Combustion: Marine	CO ₂	49.17	38.73	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	38.32	0.01	0.94
CH ₄ Emissions from Manure Management	CH ₄	31.19	36.39	0.01	0.95
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	31.70	<0.01	0.95
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	29.95	<0.01	0.96
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	21.66	<0.01	0.96
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	21.22	<0.01	0.97
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	20.65	<0.01	0.97

Fugitive Emissions from Oil Operations	CH ₄	19.97	18.79	<0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	17.76	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.34	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	14.68	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	13.69	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.55	<0.01	0.98
PFC Emissions from Aluminum Production	PFCs	18.34	10.99	<0.01	0.98
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	10.31	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	8.09	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	7.87	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.48	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	7.38	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	7.24	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	6.34	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	6.32	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.12	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.62	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.35	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	3.84	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.92	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	2.04	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.84	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.74	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.64	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.54	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.25	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.81	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.77	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.45	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.38	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.38	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.32	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.30	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.06	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,677.52	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-11: 1998 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)	1998 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,936.49	0.29	0.29
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,419.71	0.21	0.50
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,134.77	0.17	0.67
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	573.65	0.09	0.75
Mobile Combustion: Aviation	CO ₂	177.24	181.33	0.03	0.78
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	158.63	0.02	0.80
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	138.49	0.02	0.82
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	135.35	0.02	0.85
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	131.79	0.02	0.86
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	116.70	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	109.12	0.02	0.90
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	67.43	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	62.76	0.01	0.92
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	56.57	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O	41.62	53.31	0.01	0.93
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	40.13	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	39.22	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄	31.19	38.85	0.01	0.95

CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	32.55	<0.01	0.96
Mobile Combustion: Marine	CO ₂	49.17	32.41	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	21.93	<0.01	0.96
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	20.88	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	18.46	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.39	<0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	17.09	<0.01	0.98
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	17.06	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	14.96	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	13.91	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.38	<0.01	0.98
PFC Emissions from Aluminum Production	PFCs	18.34	9.05	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.90	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	7.45	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	7.15	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	7.13	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	6.88	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	6.57	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.14	<0.01	0.99
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	5.99	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.79	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	5.79	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.32	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	3.68	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	3.01	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	2.03	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.82	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.77	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.68	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.59	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.20	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.91	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.79	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.46	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.38	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.35	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.35	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.27	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.05	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,719.75	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-12: 1999 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct		Level Assessment	Cumulative Total	
	Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)			1999 Estimate (Tg CO ₂ Eq.)
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,938.19	0.29	0.29
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,461.77	0.22	0.50
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,138.03	0.17	0.67
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	578.54	0.09	0.76
Mobile Combustion: Aviation	CO ₂	177.24	186.74	0.03	0.79
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	151.10	0.02	0.81
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	141.58	0.02	0.83
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	134.02	0.02	0.85
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	127.39	0.02	0.87
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	116.78	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	92.31	0.01	0.90
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	65.81	0.01	0.91
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	64.38	0.01	0.92

Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	58.89	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O	41.62	52.46	0.01	0.93
Mobile Combustion: Marine	CO ₂	49.17	42.26	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	39.99	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄	31.19	38.76	0.01	0.95
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	33.65	<0.01	0.96
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	30.42	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	20.61	<0.01	0.96
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	20.12	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	17.81	<0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	17.63	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.41	<0.01	0.98
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	16.39	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	15.45	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.48	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	13.47	<0.01	0.98
PFC Emissions from Aluminum Production	PFCs	18.34	8.96	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	8.29	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	8.06	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	7.32	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	7.23	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	7.10	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	6.94	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.16	<0.01	0.99
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	6.01	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.90	<0.01	0.99
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	5.48	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.22	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	3.39	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	3.05	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	2.00	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.85	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.82	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.71	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.54	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.17	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.85	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.77	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.47	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.45	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.38	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.35	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.33	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.07	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.02	<0.01	1.00
TOTAL		6,088.11	6,752.23	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-13: 2000 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct		2000 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
	Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)			
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	2,025.62	0.29	0.29
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,481.40	0.21	0.50
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,188.67	0.17	0.68
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	592.74	0.09	0.76
Mobile Combustion: Aviation	CO ₂	177.24	193.18	0.03	0.79
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	156.28	0.02	0.81
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	132.06	0.02	0.83
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	130.68	0.02	0.85

CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	124.71	0.02	0.87
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	115.60	0.02	0.88
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	107.58	0.02	0.90
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	75.01	0.01	0.91
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	65.69	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	63.11	0.01	0.93
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	56.22	0.01	0.94
Mobile Combustion: Road & Other	N ₂ O	41.62	50.77	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	41.19	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄	31.19	38.08	0.01	0.95
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	34.34	<0.01	0.96
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	29.79	<0.01	0.96
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	19.62	<0.01	0.97
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	19.59	<0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	17.98	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.81	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	17.55	<0.01	0.98
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	15.65	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	15.56	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	14.00	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	13.31	<0.01	0.99
PFC Emissions from Aluminum Production	PFCs	18.34	8.95	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	7.74	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.49	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	7.34	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	6.30	<0.01	0.99
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	6.04	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	5.98	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	5.96	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	5.77	<0.01	0.99
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	5.72	<0.01	1.00
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.18	<0.01	1.00
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	3.18	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	3.12	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	3.00	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.92	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.88	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.72	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.68	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.38	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.21	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.96	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.79	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.51	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.46	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.36	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.35	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.35	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.16	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.10	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.01	<0.01	1.00
TOTAL		6,088.11	6,953.18	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-14: 2001 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct		2001 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
	Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)			
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,959.21	0.29	0.29
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,493.54	0.22	0.51
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,140.52	0.17	0.67

CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	628.19	0.09	0.77
Mobile Combustion: Aviation	CO ₂	177.24	183.41	0.03	0.79
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	154.46	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	131.82	0.02	0.84
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	126.21	0.02	0.85
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	120.10	0.02	0.87
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	114.54	0.02	0.89
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	102.65	0.02	0.90
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	83.25	0.01	0.92
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	58.89	0.01	0.93
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	55.60	0.01	0.93
Mobile Combustion: Road & Other	N ₂ O	41.62	46.82	0.01	0.94
Mobile Combustion: Marine	CO ₂	49.17	42.74	0.01	0.95
CO ₂ Emissions from Cement Production	CO ₂	33.28	41.36	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄	31.19	38.92	0.01	0.96
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	34.66	0.01	0.96
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	19.82	<0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	18.78	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	18.03	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	17.45	<0.01	0.97
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	16.72	<0.01	0.98
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	15.91	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	15.63	<0.01	0.98
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	15.42	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.46	<0.01	0.99
CO ₂ Emissions from Lime Production	CO ₂	11.24	12.82	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	7.64	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	6.95	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	6.67	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	6.09	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	5.81	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	5.73	<0.01	0.99
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	4.92	<0.01	0.99
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	4.47	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.15	<0.01	1.00
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	4.11	<0.01	1.00
PFC Emissions from Aluminum Production	PFCs	18.34	4.00	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	2.88	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.79	<0.01	1.00
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	2.55	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	1.86	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.79	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.43	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.33	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.26	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.07	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.82	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.77	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.46	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.40	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.39	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.35	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.35	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.15	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.07	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.01	<0.01	1.00
TOTAL		6,088.11	6,806.94	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-15: 2002 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct	1990 Estimate	2002 Estimate	Level	Cumulative
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	Greenhouse Gas	(Tg CO ₂ Eq.)	(Tg CO ₂ Eq.)	Assessment	Total
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	1,973.11	0.29	0.29
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,520.12	0.22	0.51
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,176.91	0.17	0.68
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	598.77	0.09	0.77
Mobile Combustion: Aviation	CO ₂	177.24	174.92	0.03	0.79
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	159.90	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	130.65	0.02	0.84
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	126.82	0.02	0.85
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	118.81	0.02	0.87
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	114.61	0.02	0.89
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	92.67	0.01	0.90
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	91.54	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	57.22	0.01	0.92
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	55.08	0.01	0.93
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	52.43	0.01	0.94
Mobile Combustion: Road & Other	N ₂ O	41.62	43.46	0.01	0.95
CO ₂ Emissions from Cement Production	CO ₂	33.28	42.90	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄	31.19	39.33	0.01	0.96
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	35.81	0.01	0.96
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	19.79	<0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	18.78	<0.01	0.97
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	18.57	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.94	<0.01	0.97
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	17.21	<0.01	0.98
Fugitive Emissions from Oil Operations	CH ₄	19.97	17.11	<0.01	0.98
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	15.68	<0.01	0.98
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	14.71	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.53	<0.01	0.99
CO ₂ Emissions from Lime Production	CO ₂	11.24	12.30	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	6.83	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	6.40	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	6.37	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	6.23	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.02	<0.01	0.99
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	5.90	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	5.88	<0.01	0.99
PFC Emissions from Aluminum Production	PFCs	18.34	5.24	<0.01	0.99
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	1.00
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	4.35	<0.01	1.00
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	4.22	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.14	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.86	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	2.66	<0.01	1.00
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	2.65	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	2.00	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.71	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.52	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.34	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.24	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.00	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	0.98	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.71	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.47	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.46	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.43	<0.01	1.00
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.39	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.37	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.14	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.09	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.01	<0.01	1.00

TOTAL	6,088.11	6,858.05	1.00
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Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-16: 2003 Key Source Tier 1 Analysis - Level Assessment

IPCC Source Categories	Direct		2003 Estimate (Tg CO ₂ Eq.)	Level Assessment	Cumulative Total
	Greenhouse Gas	1990 Estimate (Tg CO ₂ Eq.)			
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	2,013.80	0.29	0.29
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,538.50	0.22	0.51
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,134.93	0.16	0.68
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	635.30	0.09	0.77
Mobile Combustion: Aviation	CO ₂	177.24	171.26	0.02	0.80
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	155.28	0.02	0.82
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	131.17	0.02	0.84
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	125.95	0.02	0.86
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	118.00	0.02	0.87
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	114.98	0.02	0.89
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	99.47	0.01	0.90
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	98.23	0.01	0.92
Mobile Combustion: Marine	CO ₂	49.17	57.45	0.01	0.93
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	53.78	0.01	0.93
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	53.76	0.01	0.94
CO ₂ Emissions from Cement Production	CO ₂	33.28	43.03	0.01	0.95
Mobile Combustion: Road & Other	N ₂ O	41.62	39.93	0.01	0.95
CH ₄ Emissions from Manure Management	CH ₄	31.19	39.14	0.01	0.96
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	36.77	0.01	0.97
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	18.78	<0.01	0.97
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.53	<0.01	0.97
Fugitive Emissions from Oil Operations	CH ₄	19.97	17.11	<0.01	0.97
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	15.88	<0.01	0.98
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	15.84	<0.01	0.98
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	15.56	<0.01	0.98
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	14.11	<0.01	0.98
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.84	<0.01	0.98
CO ₂ Emissions from Lime Production	CO ₂	11.24	12.98	<0.01	0.99
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	12.33	<0.01	0.99
CH ₄ Emissions from Rice Production	CH ₄	7.12	6.89	<0.01	0.99
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	6.70	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	6.43	<0.01	0.99
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.02	<0.01	0.99
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	6.01	<0.01	0.99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	5.97	<0.01	0.99
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	0.99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	4.72	<0.01	0.99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	4.34	<0.01	1.00
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	4.22	<0.01	1.00
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.08	<0.01	1.00
PFC Emissions from Aluminum Production	PFCs	18.34	3.80	<0.01	1.00
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	2.97	<0.01	1.00
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.78	<0.01	1.00
Mobile Combustion: Road & Other	CH ₄	4.55	2.46	<0.01	1.00
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	2.01	<0.01	1.00
Mobile Combustion: Aviation	N ₂ O	1.72	1.67	<0.01	1.00
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.52	<0.01	1.00
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.38	<0.01	1.00
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.37	<0.01	1.00
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	1.27	<0.01	1.00
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.02	<0.01	1.00
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.79	<0.01	1.00
Mobile Combustion: Marine	N ₂ O	0.39	0.46	<0.01	1.00
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.46	<0.01	1.00
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.44	<0.01	1.00

N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.39	<0.01	1.00
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.34	<0.01	1.00
Mobile Combustion: Aviation	CH ₄	0.16	0.14	<0.01	1.00
Mobile Combustion: Marine	CH ₄	0.08	0.09	<0.01	1.00
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.01	<0.01	1.00
TOTAL		6,088.11	6,900.23	1.00	

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

Table 1-17: 1990-2003 Key Source Tier 1 Analysis - Trend Assessment

IPCC Source Categories	Direct GHG	1990	2003	Trend Assessment	Percent Contribution to Trend	Cumulative Total
		Estimate (TgCO ₂ Eq.)	Estimate (Tg CO ₂ Eq.)			
Mobile Combustion: Road & Other	CO ₂	1,220.43	1,538.50	0.02	18	18
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,680.89	2,013.80	0.01	13	31
Emissions from Substitutes for Ozone Depleting Substances	Several	0.40	99.47	0.01	12	43
CH ₄ Emissions from Solid Waste Disposal Sites	CH ₄	172.23	131.17	0.01	8	50
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	609.99	635.30	0.01	7	57
CO ₂ Emissions from Iron and Steel Production	CO ₂	85.41	53.76	0.01	5	62
Fugitive Emissions from Coal Mining and Handling	CH ₄	81.89	53.78	<0.01	5	67
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	973.63	1,134.93	<0.01	4	70
Mobile Combustion: Aviation	CO ₂	177.24	171.26	<0.01	3	74
Indirect N ₂ O Emissions from Nitrogen Used in Agriculture	N ₂ O	112.63	98.23	<0.01	3	77
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	34.98	12.33	<0.01	3	80
Fugitive Emissions from Natural Gas Operations	CH ₄	128.35	125.95	<0.01	2	83
SF ₆ Emissions from Electrical Equipment	SF ₆	29.22	14.11	<0.01	2	85
CH ₄ Emissions from Enteric Fermentation in Domestic Livestock	CH ₄	117.86	114.98	<0.01	2	87
PFC Emissions from Aluminum Production	PFCs	18.34	3.80	<0.01	2	89
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.20	6.01	<0.01	1	91
CH ₄ Emissions from Wastewater Handling	CH ₄	24.85	36.77	<0.01	1	92
Mobile Combustion: Road & Other	N ₂ O	41.62	39.93	<0.01	1	92
CO ₂ Emissions from Waste Incineration	CO ₂	10.92	18.78	<0.01	1	93
CO ₂ Emissions from Ammonia Production and Urea Application	CO ₂	19.31	15.56	<0.01	1	94
Fugitive Emissions from Oil Operations	CH ₄	19.97	17.11	<0.01	1	95
CO ₂ Emissions from Cement Production	CO ₂	33.28	43.03	<0.01	1	95
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.85	15.84	<0.01	1	96
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	107.96	118.00	<0.01	1	96
Direct N ₂ O Emissions from Agricultural Soils	N ₂ O	140.36	155.28	<0.01	0	97
CH ₄ Emissions from Manure Management	CH ₄	31.19	39.14	<0.01	0	97
SF ₆ Emissions from Magnesium Production	SF ₆	5.37	2.97	<0.01	0	97
CO ₂ Emissions from Aluminum Production	CO ₂	6.31	4.22	<0.01	0	98
Mobile Combustion: Road & Other	CH ₄	4.55	2.46	<0.01	0	98
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.84	6.70	<0.01	0	98
Mobile Combustion: Marine	CO ₂	49.17	57.45	<0.01	0	99
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.53	4.72	<0.01	0	99
CH ₄ Emissions from Rice Production	CH ₄	7.12	6.89	<0.01	0	99
N ₂ O Emissions from Wastewater Handling	N ₂ O	13.02	15.88	<0.01	0	99
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	SF ₆	2.91	4.34	<0.01	0	99
N ₂ O Emissions from Manure Management	N ₂ O	16.26	17.53	<0.01	0	99
CO ₂ Emissions from Ferroalloys	CO ₂	1.98	1.37	<0.01	0	99
CO ₂ Emissions from Soda Ash Manufacture and Consumption	CO ₂	4.14	4.08	<0.01	0	99
CO ₂ Emissions from Natural Gas Flaring	CO ₂	5.81	5.97	<0.01	0	100
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.31	2.01	<0.01	0	100
CH ₄ Emissions from Iron and Steel Production	CH ₄	1.32	1.02	<0.01	0	100
Fugitive Emissions from Abandoned Coal Mines	CH ₄	6.06	6.43	<0.01	0	100
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.53	1.38	<0.01	0	100
N ₂ O Emissions from Forest Land Remaining Forest Land	N ₂ O	0.06	0.39	<0.01	0	100
CO ₂ Emissions from CO ₂ Consumption	CO ₂	0.86	1.27	<0.01	0	100
Mobile Combustion: Aviation	N ₂ O	1.72	1.67	<0.01	0	100
CO ₂ Emissions from Petrochemical Production	CO ₃	2.22	2.78	<0.01	0	100
N ₂ O Emissions from Settlements Remaining Settlements	N ₂ O	5.54	6.02	<0.01	0	100
CO ₂ Emissions from Lime Production	CO ₂	11.24	12.98	<0.01	0	100
CH ₄ Emissions from Petrochemical Production	CH ₄	1.17	1.52	<0.01	0	100

CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.40	0.34	<0.01	0	100
N ₂ O Emissions from N ₂ O Product Usage	N ₂ O	4.30	4.77	<0.01	0	100
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.26	13.84	<0.01	0	100
Mobile Combustion: Aviation	CH ₄	0.16	0.14	<0.01	0	100
CH ₄ Emissions from Silicon Carbide Production	CH ₄	0.03	0.01	<0.01	0	100
Mobile Combustion: Marine	N ₂ O	0.39	0.46	<0.01	0	100
N ₂ O Emissions from Agricultural Residue Burning	N ₂ O	0.37	0.44	<0.01	0	100
N ₂ O Emissions from Waste Incineration	N ₂ O	0.42	0.46	<0.01	0	100
CH ₄ Emissions from Agricultural Residue Burning	CH ₄	0.69	0.79	<0.01	0	100
Mobile Combustion: Marine	CH ₄	0.08	0.09	<0.01	0	100
TOTAL		6,088.11	6,900.23	0.11		

Note: Sinks (e.g., LUCF, Landfill Carbon Storage) are not included in this analysis.

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 CO₂ Emissions from Fossil Fuel Combustion

2.1. Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion

Carbon dioxide (CO₂) emissions from fossil fuel combustion were estimated using a “bottom-up” methodology characterized by 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 CO₂ emissions from fossil fuel combustion is conceptually similar to the approach recommended by the Intergovernmental Panel on Climate Change (IPCC) for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). Adjusted consumption data are presented in Columns 2 through 8 of Table 2-1 through Table 2-14, 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 2003 total adjusted energy consumption across all sectors, including territories, and energy types was 76,929.4 trillion British thermal units (Tbtu), as indicated in the last entry of Column 8 in Table 2-1. This total excludes fuel used for non-energy purposes and fuel consumed as international bunkers, both of which were deducted in earlier steps.

Electricity consumption information was allocated to each sector based on EIA’s distribution of electricity retail sales to ultimate customers (i.e., residential, commercial, industrial, and other). Because the “other” fuel use includes sales to both the commercial and transportation sectors, EIA’s limited transportation electricity use data were subtracted from “other” electricity use and also reported separately. This total was consequently combined with the commercial electricity data. Further information on these electricity end uses is described in EIA’s *Monthly Energy Review* (2004a).

There are also three basic differences between the consumption data presented in Table 2-1 through Table 2-14 and those recommended in the IPCC emission inventory methodology.

First, consumption data in the U.S. inventory are presented using higher heating values (HHV)¹ rather than the lower heating values (LHV)² reflected in the IPCC emission inventory methodology. This convention is followed because data obtained from EIA are based on HHV. Of note, however, is that EIA renewable energy statistics are often published using LHV. The difference between the two conventions relates to the treatment of the heat energy that is consumed in the process of evaporating the water contained in the fuel. The simplified convention used by the International Energy Agency for converting from HHV to LHV is to multiply the energy content by 0.95 for petroleum and coal and by 0.9 for natural gas.

¹ Also referred to as Gross Calorific Values (GCV).

² Also referred to as Net Calorific Values (NCV).

Second, while EIA's energy use data for the United States includes only the 50 U.S. states and the District of Columbia, the data reported to the 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 2-1 through Table 2-14. 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 five fuel categories—coking 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 is 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, 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 CO₂ is not emitted to the atmosphere in the United States, and therefore the energy used to produce this amount of CO₂ is subtracted from industrial other coal.

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 CO₂ 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 2-15, 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 2-16). 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 2-1 through Table 2-14) by fuel-specific carbon content coefficients (see Table 2-17 and Table 2-18) 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 2-17 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 (CO₂). A much smaller portion of this “oxidized” carbon is also emitted as carbon

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 (CH₄), and non-methane volatile organic compounds (NMVOCs). When in the atmosphere, though, these partially oxidized or unoxidized carbon compounds are generally oxidized to CO₂ through atmospheric processes (e.g., reaction with hydroxyl (OH)).⁵

Step 8: Summarize Emission Estimates

Actual CO₂ emissions in the United States were summarized by major fuel (i.e., coal, petroleum, natural gas, geothermal) and consuming sector (i.e., residential, commercial, industrial, transportation, electricity generation, and U.S. territories). Emission estimates are expressed in teragrams of carbon dioxide equivalents (Tg CO₂ Eq.).

To 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 2-19). 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 CO₂ from CH₄ Oxidation box in the Energy chapter for a discussion of accounting of carbon from hydrocarbon and CO emissions.

Table 2-1: 2003 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

Fuel Type	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.0	99.0	1,321.2	NE	20,068.2	39.6	21,539.9	1.1	9.3	123.4	NE	1,876.3	3.6	2,013.8
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		99.0					99.0		9.3					9.3
Industrial Coking Coal														
Industrial Other Coal			1,259.1				1,259.1			117.2				117.2
Coke Imports			62.1				62.1			6.3				6.3
Transportation Coal				NE										NE
Utility Coal					20,068.2		20,068.2					1,876.3		1,876.3
U.S. Territory Coal (bit)						39.6	39.6						3.6	3.6
Natural Gas	5,253.0	3,233.0	7,726.3	670.0	5,259.2	26.86	22,168.4	277.3	170.7	407.9	35.4	277.6	1.4	1,170.3
Total Petroleum	1,546.1	753.2	4,519.9	24,461.6	1,197.7	697.7	33,176.2	106.7	53.9	327.3	1,731.8	96.3	51.2	2,367.1
Asphalt & Road Oil														
Aviation Gasoline				32.7			32.7				2.2			2.2
Distillate Fuel Oil	930.6	520.8	1,308.5	5,338.9	160.3	119.9	8,379.0	67.4	37.7	94.8	386.6	11.6	8.7	606.8
Jet Fuel				2,408.6		105.9	2,514.5				169.0		7.4	176.5
Kerosene	71.8	23.7	17.5			1.0	114.0	5.1	1.7	1.3			0.1	8.2
LPG	543.7	96.0	608.2	13.1		7.6	1,268.6	34.1	6.0	38.2	0.8		0.5	79.6
Lubricants														
Motor Gasoline		38.9	306.0	16,290.6		209.9	16,845.4		2.7	21.5	1,143.7		14.7	1,182.6
Residual Fuel		73.6	157.5	377.6	875.3	253.4	1,737.4		5.7	12.3	29.5	68.3	19.8	135.5
Other Petroleum														
AvGas Blend Components			7.5				7.5			0.5				0.5
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)			24.560				24.6			1.6				1.6
Other Oil (>401 deg. F)			25.480				25.5			1.8				1.8
Pentanes Plus			58.4				58.4			3.9				3.9
Petroleum Coke		0.3	650.4		162.1		812.7		0.0	65.7		16.4		82.2
Still Gas			1,403.3				1,403.3			89.2				89.2
Special Naphtha			2.9				2.9			0.2				0.2
Unfinished Oils			(50.4)				(50.4)			(3.7)				(3.7)
Waxes														
Geothermal					44.9		44.9					0.3		0.3
TOTAL (All Fuels)	6,811.1	4,085.2	13,567.3	25,131.6	26,569.9	764.2	76,929.4	385.1	234.0	858.6	1,767.2	2,250.5	56.2	5,551.6

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-2: 2002 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

Fuel Type	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	11.0	91.0	1,313.0	NE	19,676.5	12.6	21,104.1	1.0	8.6	122.7	NE	1,839.7	1.2	1,973.1
Residential Coal	11.0						11.0	1.0						1.0
Commercial Coal		91.0					91.0		8.6					8.6
Industrial Coking Coal										116.4				116.4
Industrial Other Coal			1,250.9				1,250.9							
Coke Imports			62.1				62.1			6.3				6.3
Transportation Coal				NE										NE
Utility Coal					19,676.5		19,676.5					1,839.7		1,839.7
U.S. Territory Coal (bit)						12.6	12.6						1.2	1.2
Natural Gas	5,036.0	3,196.0	8,249.4	702.0	5,789.3	22.87	22,995.6	265.9	168.7	435.5	37.1	305.6	1.2	1,214.0
Total Petroleum	1,519.1	736.7	4,400.6	24,233.1	952.9	623.6	32,466.0	104.5	52.7	318.4	1,715.2	77.4	45.7	2,314.0
Asphalt & Road Oil														
Aviation Gasoline				33.7			33.7				2.3			2.3
Distillate Fuel Oil	896.1	502.8	1,259.1	5,150.4	126.8	106.5	8,041.7	64.9	36.4	91.2	373.0	9.2	7.7	582.4
Jet Fuel				2,459.8		93.8	2,553.6				172.6		6.6	179.2
Kerosene	57.0	18.8	13.9			0.9	90.6	4.1	1.3	1.0			0.1	6.5
LPG	566.0	99.9	621.9	13.7		7.0	1,308.5	35.5	6.3	39.0	0.9		0.4	82.1
Lubricants														
Motor Gasoline		38.5	303.1	16,219.8		188.0	16,749.5		2.7	21.3	1,138.7		13.2	1,175.9
Residual Fuel		76.4	167.5	355.7	663.4	227.4	1,490.4		6.0	13.1	27.7	51.7	17.7	116.3
Other Petroleum														
AvGas Blend Components			7.5				7.5			0.5				0.5
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)			23.3				23.3			1.5				1.5
Other Oil (>401 deg. F)			23.0				23.0			1.7				1.7
Pentanes Plus			59.3				59.3			3.9				3.9
Petroleum Coke		0.3	650.0		162.7		813.0		0.0	65.7		16.4		82.2
Still Gas			1,403.9				1,403.9			89.2				89.2
Special Naphtha			3.7				3.7			0.3				0.3
Unfinished Oils			(135.7)				(135.7)			(10.0)				(10.0)
Waxes														
Geothermal					49.4		49.4					0.4		0.4
TOTAL (All Fuels)	6,566.1	4,023.7	13,962.9	24,935.1	26,468.2	659.1	76,615.1	371.4	230.0	876.6	1,752.3	2,223.0	48.1	5,501.4

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-3: 2001 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

Fuel Type	Adjusted Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use						
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.0	97.0	1,399.3	NE	19,438.8	10.2	20,957.2	1.1	9.2	130.6	NE	1,817.4	0.9	1,959.2
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		97.0					97.0		9.2					9.2
Industrial Coking Coal			1.1				1.1			0.1				0.1
Industrial Other Coal			1,355.2				1,355.2			126.1				126.1
Coke Imports			43.0				43.0			4.3				4.3
Transportation Coal				NE										NE
Utility Coal					19,438.8		19,438.8					1,817.4		1,817.4
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,919.0	3,116.0	8,069.8	642.0	5,476.5	22.92	22,246.2	259.7	164.5	426.0	33.9	289.1	1.2	1,174.4
Total Petroleum	1,538.6	741.8	4,441.5	23,833.8	1,275.5	633.8	32,465.0	106.2	53.1	321.6	1,685.8	100.9	46.5	2,314.0
Asphalt & Road Oil														
Aviation Gasoline				34.9			34.9				2.4			2.4
Distillate Fuel Oil	908.3	508.4	1,276.6	5,219.3	161.1	109.4	8,183.1	65.8	36.8	92.4	378.0	11.7	7.9	592.6
Jet Fuel				2,579.7			2,678.5				181.0		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	570.2	12.9		7.0	1,219.8	33.6	5.9	35.8	0.8		0.4	76.6
Lubricants														
Motor Gasoline		37.5	295.1	15,827.5		189.2	16,349.2		2.6	20.7	1,111.2		13.3	1,147.8
Residual Fuel		69.9	146.7	159.5	1,015.8	228.4	1,620.3		5.4	11.4	12.4	79.2	17.8	126.4
Other Petroleum														
AvGas Blend Components			6.1				6.1			0.4				0.4
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)			20.5				20.5			1.3				1.3
Other Oil (>401 deg. F)			25.0				25.0			1.8				1.8
Pentanes Plus			69.9				69.9			4.6				4.6
Petroleum Coke		0.2	650.0			98.5	748.7		0.0	65.7		10.0		75.7
Still Gas			1,430.7				1,430.7			90.9				90.9
Special Naphtha			3.0				3.0			0.2				0.2
Unfinished Oils			(75.4)				(75.4)			(5.6)				(5.6)
Waxes														
Geothermal					46.9		46.9					0.4		0.4
TOTAL (All Fuels)	6,469.6	3,954.8	13,910.5	24,475.8	26,237.7	666.9	75,715.3	367.0	226.7	878.2	1,719.7	2,207.8	48.6	5,448.0

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-4: 2000 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	12.0	91.0	1,443.8	NE	20,108.1	10.2	21,665.1	1.1	8.6	135.0	NE	1,880.0	0.9	2,025.6	
Residential Coal	12.0						12.0	1.1						1.1	
Commercial Coal		91.0					91.0		8.6					8.6	
Industrial Coking Coal															
Industrial Other Coal			1,366.8				1,366.8			127.2				127.2	
Coke Imports			77.0				77.0			7.8				7.8	
Transportation Coal				NE										NE	
Utility Coal					20,108.1		20,108.1					1,880.0		1,880.0	
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9	
Natural Gas	5,121.0	3,265.0	8,800.0	672.0	5,317.7	12.67	23,188.4	270.3	172.4	464.6	35.5	280.7	0.7	1,224.1	
Total Petroleum	1,563.1	756.4	4,250.6	24,040.4	1,151.4	473.2	32,235.1	107.7	54.2	305.5	1,702.2	91.0	34.3	2,295.0	
Asphalt & Road Oil															
Aviation Gasoline				36.3			36.3				2.5			2.5	
Distillate Fuel Oil	904.8	491.0	1,177.0	5,078.7	174.7	71.3	7,897.4	65.5	35.6	85.2	367.8	12.6	5.2	571.9	
Jet Fuel				2,717.5		74.1	2,791.6				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	773.5	11.2		8.0	1,455.8	35.4	6.2	48.5	0.7		0.5	91.4	
Lubricants															
Motor Gasoline		44.6	150.2	15,753.2		186.6	16,134.6		3.1	10.5	1,105.9		13.1	1,132.7	
Residual Fuel		91.6	184.1	443.5	882.2	130.9	1,732.2		7.1	14.4	34.6	68.8	10.2	135.1	
Other Petroleum															
AvGas Blend Components			3.8				3.8			0.3				0.3	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)			57.4				57.4			3.8				3.8	
Other Oil (>401 deg. F)			61.5				61.5			4.5				4.5	
Pentanes Plus			128.7				128.7			8.5				8.5	
Petroleum Coke		0.2	655.4		94.6		750.1		0.0	66.3		9.6		75.8	
Still Gas			1,436.5				1,436.5			91.3				91.3	
Special Naphtha			8.3				8.3			0.6				0.6	
Unfinished Oils			(401.4)				(401.4)			(29.5)				(29.5)	
Waxes															
Geothermal					48.1		48.1					0.4		0.4	
TOTAL (All Fuels)	6,696.1	4,112.4	14,494.4	24,712.4	26,625.3	496.1	77,136.7	379.1	235.2	905.0	1,737.7	2,252.1	35.9	5,545.1	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-5: 1999 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

Fuel Type	Adjusted Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	14.0	103.0	1,432.2	NE	19,171.0	10.2	20,730.4	1.3	9.7	133.8	NE	1,792.4	0.9	1,938.2
Residential Coal	14.0						14.0	1.3						1.3
Commercial Coal		103.0					103.0		9.7					9.7
Industrial Coking Coal														
Industrial Other Coal			1,362.2				1,362.2			126.7				126.7
Coke Imports			70.0				70.0			7.1				7.1
Transportation Coal				NE										NE
Utility Coal					19,171.0		19,171.0					1,792.4		1,792.4
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,858.0	3,130.0	8,645.5	674.0	4,923.5	-	22,231.1	256.5	165.2	456.4	35.6	259.9		1,173.6
Total Petroleum	1,472.7	661.4	4,119.4	23,414.6	1,217.4	484.8	31,370.3	101.5	47.3	297.8	1,655.2	96.7	35.2	2,233.7
Asphalt & Road Oil														
Aviation Gasoline				39.2			39.2				2.7			2.7
Distillate Fuel Oil	827.8	438.4	1,163.9	4,887.4	140.0	80.8	7,538.3	59.9	31.8	84.3	353.9	10.1	5.9	545.9
Jet Fuel				2,622.9		76.1	2,699.0				184.1		5.3	189.4
Kerosene	111.2	26.9	12.8			3.7	154.7	8.0	1.9	0.9			0.3	11.1
LPG	533.8	94.2	604.4	13.5		8.4	1,254.2	33.6	5.9	38.0	0.8		0.5	78.9
Lubricants														
Motor Gasoline		28.4	151.7	15,675.9		178.5	16,034.5		2.0	10.6	1,099.9		12.5	1,125.1
Residual Fuel		73.3	150.9	175.7	970.4	137.3	1,507.7		5.7	11.8	13.7	75.7	10.7	117.6
Other Petroleum														
AvGas Blend Components			6.4				6.4			0.4				0.4
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)			43.4				43.4			2.9				2.9
Other Oil (>401 deg. F)			63.7				63.7			4.6				4.6
Pentanes Plus			125.9				125.9			8.3				8.3
Petroleum Coke		0.1	651.9		106.9		758.9		0.0	65.9		10.8		76.7
Still Gas			1,420.8				1,420.8			90.3				90.3
Special Naphtha			11.5				11.5			0.8				0.8
Unfinished Oils			(287.9)				(287.9)			(21.1)				(21.1)
Waxes														
Geothermal					50.9		50.9					0.4		0.4
TOTAL (All Fuels)	6,344.7	3,894.4	14,197.1	24,088.6	25,362.8	495.0	74,382.6	359.3	222.3	888.1	1,690.8	2,149.3	36.2	5,345.9

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-6: 1998 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	13.0	92.0	1,489.4	NE	19,106.8	10.5	20,711.7	1.2	8.7	139.2	NE	1,786.4	1.0	1,936.5	
Residential Coal	13.0						13.0	1.2						1.2	
Commercial Coal		92.0					92.0		8.7					8.7	
Industrial Coking Coal															
Industrial Other Coal			1,409.4				1,409.4			131.1				131.1	
Coke Imports			80.0				80.0			8.1				8.1	
Transportation Coal				NE										NE	
Utility Coal					19,106.8		19,106.8					1,786.4		1,786.4	
U.S. Territory Coal (bit)						10.5	10.5						1.0	1.0	
Natural Gas	4,669.0	3,098.0	9,030.8	665.0	4,697.5	-	22,160.3	246.5	163.5	476.7	35.1	248.0		1,169.9	
Total Petroleum	1,313.8	660.8	4,077.9	22,623.1	1,312.0	486.1	30,473.7	90.9	47.5	295.6	1,598.3	104.3	35.4	2,172.0	
Asphalt & Road Oil															
Aviation Gasoline				35.5			35.5				2.4			2.4	
Distillate Fuel Oil	771.9	428.8	1,188.2	4,652.7	135.8	90.0	7,267.4	55.9	31.1	86.0	336.9	9.8	6.5	526.3	
Jet Fuel				2,549.4		76.0	2,625.4				178.9		5.3	184.2	
Kerosene	108.3	31.2	22.1			6.0	167.5	7.8	2.2	1.6			0.4	12.0	
LPG	433.6	76.5	480.1	16.6		5.9	1,012.8	27.3	4.8	30.2	1.0		0.4	63.7	
Lubricants															
Motor Gasoline		39.0	199.4	15,289.9		167.1	15,695.5		2.7	14.0	1,072.9		11.7	1,101.3	
Residual Fuel		85.2	173.3	78.9	1,059.8	141.0	1,538.2		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)			54.9				54.9				3.6			3.6	
Other Oil (>401 deg. F)			70.0				70.0				5.1			5.1	
Pentanes Plus			108.8				108.8				7.2			7.2	
Petroleum Coke		0.1	644.6		116.4		761.2		0.0	65.2		11.8		76.9	
Still Gas			1,437.3				1,437.3				91.4			91.4	
Special Naphtha			9.2				9.2				0.7			0.7	
Unfinished Oils			(313.9)				(313.9)				(23.1)			(23.1)	
Waxes															
Geothermal					50.4		50.4					0.4		0.4	
TOTAL (All Fuels)	5,995.8	3,850.8	14,598.1	23,288.1	25,166.7	496.6	73,396.1	338.6	219.7	911.6	1,633.4	2,139.0	36.3	5,278.7	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-7: 1997 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

Fuel Type	Adjusted Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use						
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	16.0	129.0	1,573.7	NE	18,806.9	10.4	20,536.0	1.5	12.2	147.2	NE	1,758.4	1.0	1,920.2
Residential Coal	16.0						16.0	1.5						1.5
Commercial Coal		129.0					129.0		12.2					12.2
Industrial Coking Coal			18.7				18.7			2.1				2.1
Industrial Other Coal			1,498.0				1,498.0			139.4				139.4
Coke Imports			57.0				57.0			5.8				5.8
Transportation Coal				NE										NE
Utility Coal					18,806.9		18,806.9					1,758.4		1,758.4
U.S. Territory Coal (bit)						10.4	10.4						1.0	1.0
Natural Gas	5,118.0	3,302.0	9,265.3	779.0	4,146.6	-	22,610.8	270.2	174.3	489.1	41.1	218.9		1,193.7
Total Petroleum	1,428.1	703.9	4,552.2	22,089.5	931.1	486.6	30,191.4	98.9	50.7	327.4	1,562.2	74.3	35.5	2,148.9
Asphalt & Road Oil														
Aviation Gasoline				39.7			39.7				2.7			2.7
Distillate Fuel Oil	874.4	443.8	1,182.2	4,546.8	110.5	92.9	7,250.6	63.3	32.1	85.6	329.3	8.0	6.7	525.1
Jet Fuel				2,511.6		76.5	2,588.1				176.2		5.4	181.6
Kerosene	92.9	24.6	18.8			3.9	140.3	6.6	1.8	1.3			0.3	10.0
LPG	460.8	81.3	693.2	13.4		5.4	1,254.2	28.9	5.1	43.5	0.8		0.3	78.6
Lubricants														
Motor Gasoline		42.7	211.8	14,841.6		163.8	15,259.9		3.0	14.9	1,042.5		11.5	1,071.9
Residual Fuel		111.2	235.6	136.5	723.4	143.9	1,350.6		8.7	18.4	10.6	56.4	11.2	105.4
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)			68.6				68.6			4.5				4.5
Other Oil (>401 deg. F)			100.1				100.1			7.2				7.2
Pentanes Plus			68.0				68.0			4.5				4.5
Petroleum Coke		0.1	609.6		97.3		707.0		0.0	61.6		9.8		71.5
Still Gas			1,445.1				1,445.1			91.8				91.8
Special Naphtha			8.4				8.4			0.6				0.6
Unfinished Oils			(102.9)				(102.9)			(7.6)				(7.6)
Waxes														
Geothermal					50.5		50.5					0.4		0.4
TOTAL (All Fuels)	6,562.1	4,134.9	15,391.1	22,868.5	23,935.1	497.0	73,388.7	370.6	237.2	963.8	1,603.3	2,051.9	36.4	5,263.2

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-8: 1996 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	17.0	122.0	1,564.8	NE	18,322.9	10.3	20,037.0	1.6	11.5	146.3	NE	1,712.3	0.9	1,872.6	
Residential Coal	17.0						17.0	1.6						1.6	
Commercial Coal		122.0					122.0		11.5					11.5	
Industrial Coking Coal			30.9				30.9			3.5				3.5	
Industrial Other Coal			1,498.9				1,498.9			139.3				139.3	
Coke Imports			35.0				35.0			3.5				3.5	
Transportation Coal				NE										NE	
Utility Coal					18,322.9		18,322.9					1,712.3		1,712.3	
U.S. Territory Coal (bit)						10.3	10.3						0.9	0.9	
Natural Gas	5,383.0	3,244.0	9,247.9	736.0	3,881.8	-	22,492.7	284.2	171.3	488.2	38.9	204.9		1,187.4	
Total Petroleum	1,488.0	751.3	4,460.1	21,966.1	820.7	480.6	29,966.8	103.1	54.3	321.8	1,555.0	65.2	35.1	2,134.5	
Asphalt & Road Oil															
Aviation Gasoline				37.4			37.4				2.6			2.6	
Distillate Fuel Oil	926.0	482.9	1,168.4	4,355.2	109.3	95.1	7,136.9	67.1	35.0	84.6	315.4	7.9	6.9	516.8	
Jet Fuel				2,530.6		73.0	2,603.5				177.6		5.1	182.7	
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	633.0	14.7		5.7	1,210.2	29.7	5.2	39.7	0.9		0.4	75.9	
Lubricants															
Motor Gasoline		26.5	199.9	14,713.3		155.2	15,094.9		1.9	14.0	1,034.0		10.9	1,060.8	
Residual Fuel		137.2	281.7	314.9	635.3	148.6	1,517.6		10.7	22.0	24.6	49.6	11.6	118.4	
Other Petroleum															
AvGas Blend Components			6.9				6.9			0.5				0.5	
Crude Oil			13.7				13.7			1.0				1.0	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)			52.8				52.8			3.5				3.5	
Other Oil (>401 deg. F)			73.1				73.1			5.3				5.3	
Pentanes Plus			73.0				73.0			4.8				4.8	
Petroleum Coke		0.1	608.6		76.1		684.8		0.0	61.5		7.7		69.2	
Still Gas			1,435.9				1,435.9			91.3				91.3	
Special Naphtha			7.5				7.5			0.5				0.5	
Unfinished Oils			(112.7)				(112.7)			(8.3)				(8.3)	
Waxes															
Geothermal					50.2		50.2					0.4		0.4	
TOTAL (All Fuels)	6,888.0	4,117.3	15,272.8	22,702.1	23,075.6	490.9	72,546.7	388.9	237.0	956.4	1,593.9	1,982.8	36.0	5,194.9	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-9: 1995 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	17.0	117.0	1,603.6	NE	17,367.3	10.2	19,115.1	1.6	11.0	150.1	NE	1,623.0	0.9	1,786.7	
Residential Coal	17.0						17.0	1.6						1.6	
Commercial Coal		117.0					117.0		11.0					11.0	
Industrial Coking Coal			20.9				20.9			2.4				2.4	
Industrial Other Coal			1,521.7				1,521.7			141.6				141.6	
Coke Imports			61.0				61.0			6.2				6.2	
Transportation Coal				NE										NE	
Utility Coal					17,367.3		17,367.3					1,623.0		1,623.0	
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9	
Natural Gas	4,981.0	3,113.0	8,952.3	723.0	4,326.6	-	22,095.9	263.0	164.3	472.6	38.2	228.4		1,166.5	
Total Petroleum	1,383.3	732.0	4,113.4	21,357.1	756.9	496.4	28,839.1	96.2	53.1	296.6	1,513.3	60.2	36.3	2,055.7	
Asphalt & Road Oil															
Aviation Gasoline				39.6			39.6				2.7			2.7	
Distillate Fuel Oil	904.8	478.9	1,114.9	4,069.2	108.2	112.6	6,788.5	65.5	34.7	80.7	294.7	7.8	8.2	491.6	
Jet Fuel				2,409.2		71.7	2,480.9				169.1		5.0	174.1	
Kerosene	74.3	22.1	15.4			3.5	115.3	5.3	1.6	1.1			0.2	8.3	
LPG	404.2	71.3	630.2	16.7		5.2	1,127.8	25.4	4.5	39.6	1.1		0.3	70.8	
Lubricants															
Motor Gasoline		18.1	200.1	14,435.1		148.4	14,801.7		1.3	14.1	1,015.5		10.4	1,041.3	
Residual Fuel		141.5	284.7	387.3	571.8	155.0	1,540.3		11.0	22.2	30.2	44.6	12.1	120.2	
Other Petroleum															
AvGas Blend Components			5.3				5.3			0.4				0.4	
Crude Oil			14.5				14.5			1.1				1.1	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)			43.2				43.2			2.8				2.8	
Other Oil (>401 deg. F)			84.3				84.3			6.1				6.1	
Pentanes Plus			69.2				69.2			4.6				4.6	
Petroleum Coke		0.1	588.6		76.9		665.6		0.0	59.5		7.8		67.3	
Still Gas			1,376.1				1,376.1			87.5				87.5	
Special Naphtha			7.5				7.5			0.5				0.5	
Unfinished Oils			(320.6)				(320.6)			(23.5)				(23.5)	
Waxes															
Geothermal					48.8		48.8					0.4		0.4	
TOTAL (All Fuels)	6,381.3	3,962.0	14,669.3	22,080.1	22,499.6	506.6	70,098.9	360.8	228.4	919.3	1,551.4	1,912.0	37.2	5,009.2	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-10: 1994 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	21.0	118.0	1,641.7	NE	17,170.5	10.0	18,961.1	2.0	11.1	153.4	NE	1,603.0	0.9	1,770.4	
Residential Coal	21.0						21.0	2.0						2.0	
Commercial Coal		118.0					118.0		11.1					11.1	
Industrial Coking Coal			8.6				8.6			1.0				1.0	
Industrial Other Coal			1,575.0				1,575.0			146.6				146.6	
Coke Imports			58.0				58.0			5.9				5.9	
Transportation Coal				NE										NE	
Utility Coal					17,170.5		17,170.5					1,603.0		1,603.0	
U.S. Territory Coal (bit)						10.0	10.0						0.9	0.9	
Natural Gas	4,988.0	2,979.0	8,475.6	708.0	3,999.6	-	21,150.3	263.3	157.3	447.4	37.4	211.1		1,116.6	
Total Petroleum	1,420.2	787.5	4,322.6	20,941.9	1,063.0	506.9	29,042.1	99.0	57.3	311.5	1,487.1	83.8	37.1	2,075.8	
Asphalt & Road Oil															
Aviation Gasoline				38.1			38.1				2.6			2.6	
Distillate Fuel Oil	959.8	500.9	1,096.8	3,910.8	119.8	118.8	6,707.0	69.5	36.3	79.4	283.2	8.7	8.6	485.7	
Jet Fuel				2,470.6		65.8	2,536.3				173.5		4.6	178.1	
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	643.9	32.2		7.3	1,148.6	24.8	4.4	40.4	2.0		0.5	72.1	
Lubricants															
Motor Gasoline		25.2	192.4	14,132.1		148.0	14,497.7		1.8	13.6	997.8		10.5	1,023.6	
Residual Fuel		171.9	368.4	358.1	876.5	164.1	1,939.0		13.4	28.7	27.9	68.4	12.8	151.3	
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)			46.3				46.3			3.1				3.1	
Other Oil (>401 deg. F)			88.7				88.7			6.4				6.4	
Pentanes Plus			110.7				110.7			7.3				7.3	
Petroleum Coke		0.1	586.6		66.7		653.4		0.0	59.3		6.7		66.1	
Still Gas			1,417.6				1,417.6			90.1				90.1	
Special Naphtha			8.6				8.6			0.6				0.6	
Unfinished Oils			(279.2)				(279.2)			(20.5)				(20.5)	
Waxes															
Geothermal					45.7		45.7					0.3		0.3	
TOTAL (All Fuels)	6,429.2	3,884.5	14,439.9	21,650.0	22,278.9	516.9	69,199.3	364.3	225.6	912.4	1,524.5	1,898.3	38.1	4,963.1	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-11: 1993 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	24.0	119.0	1,611.9	NE	17,111.0	9.6	18,875.5	2.3	11.2	150.2	NE	1,596.7	0.9	1,761.3	
Residential Coal	24.0						24.0	2.3						2.3	
Commercial Coal		119.0					119.0		11.2					11.2	
Industrial Coking Coal			9.3				9.3			1.0				1.0	
Industrial Other Coal			1,575.6				1,575.6			146.5				146.5	
Coke Imports			27.0				27.0			2.7				2.7	
Transportation Coal				NE										NE	
Utility Coal					17,111.0		17,111.0					1,596.7		1,596.7	
U.S. Territory Coal (bit)						9.6	9.6						0.9	0.9	
Natural Gas	5,095.0	2,942.0	8,498.6	644.0	3,559.4	-	20,739.0	269.0	155.3	448.7	34.0	187.9		1,094.8	
Total Petroleum	1,448.0	779.9	4,241.6	20,408.4	1,130.2	459.9	28,468.0	101.0	56.7	306.3	1,448.4	89.4	33.8	2,035.4	
Asphalt & Road Oil															
Aviation Gasoline				38.4			38.4				2.6			2.6	
Distillate Fuel Oil	973.8	493.0	1,103.0	3,649.2	86.5	104.9	6,410.4	70.5	35.7	79.9	264.3	6.3	7.6	464.2	
Jet Fuel				2,352.9			2,415.0				165.5		4.4	169.8	
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	654.5	19.0		4.9	1,147.3	25.0	4.4	41.1	1.2		0.3	72.1	
Lubricants															
Motor Gasoline		29.6	179.5	13,981.4		128.3	14,318.8		2.1	12.7	986.1		9.0	1,009.9	
Residual Fuel		172.7	391.5	367.5	969.6	155.9	2,057.2		13.5	30.5	28.7	75.6	12.2	160.5	
Other Petroleum															
AvGas Blend Components			0.1				0.1			0.0				0.0	
Crude Oil			21.1				21.1			1.6				1.6	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)			50.7				50.7			3.3				3.3	
Other Oil (>401 deg. F)			111.1				111.1			8.0				8.0	
Pentanes Plus			96.0				96.0			6.4				6.4	
Petroleum Coke		0.2	601.6		74.2		676.0		0.0	60.8		7.5		68.3	
Still Gas			1,401.4				1,401.4			89.1				89.1	
Special Naphtha			13.8				13.8			1.0				1.0	
Unfinished Oils			(395.9)				(395.9)			(29.1)				(29.1)	
Waxes															
Geothermal					52.9		52.9					0.4		0.4	
TOTAL (All Fuels)	6,567.0	3,840.9	14,352.2	21,052.4	21,853.5	469.4	68,135.4	372.2	223.2	905.2	1,482.4	1,874.4	34.6	4,892.0	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-12: 1992 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	24.0	118.0	1,599.5	NE	16,401.5	8.8	18,151.9	2.3	11.2	149.0	NE	1,529.8	0.8	1,693.1	
Residential Coal	24.0						24.0	2.3						2.3	
Commercial Coal		118.0					118.0		11.2					11.2	
Industrial Coking Coal															
Industrial Other Coal			1,564.5				1,564.5			145.5				145.5	
Coke Imports			35.0				35.0			3.5				3.5	
Transportation Coal				NE										NE	
Utility Coal					16,401.5		16,401.5					1,529.8		1,529.8	
U.S. Territory Coal (bit)						8.8	8.8						0.8	0.8	
Natural Gas	4,835.0	2,890.0	8,360.8	608.0	3,534.8	-	20,228.6	255.2	152.6	441.4	32.1	186.6		1,067.9	
Total Petroleum	1,427.2	854.0	4,508.0	20,013.9	997.3	444.9	28,245.3	99.6	62.1	322.3	1,420.2	78.4	32.6	2,015.2	
Asphalt & Road Oil															
Aviation Gasoline				41.1			41.1				2.8			2.8	
Distillate Fuel Oil	979.7	506.7	1,093.1	3,538.0	73.5	91.8	6,282.7	70.9	36.7	79.2	256.2	5.3	6.6	455.0	
Jet Fuel				2,334.9		61.3	2,396.2				164.3		4.3	168.6	
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	685.7	18.3		11.9	1,165.9	24.0	4.2	43.1	1.2		0.7	73.2	
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	881.3	154.6	1,953.4		14.8	25.6	31.2	68.7	12.1	152.4	
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)			54.5				54.5				3.6			3.6	
Other Oil (>401 deg. F)			107.1				107.1				7.8			7.8	
Pentanes Plus			270.1				270.1				17.9			17.9	
Petroleum Coke		0.1	566.5		42.6		609.2		0.0	57.3		4.3		61.6	
Still Gas			1,436.5				1,436.5			91.3				91.3	
Special Naphtha			13.8				13.8			1.0				1.0	
Unfinished Oils			(355.0)				(355.0)			(26.1)				(26.1)	
Waxes															
Geothermal					57.3		57.3					0.4		0.4	
TOTAL (All Fuels)	6,286.2	3,862.0	14,468.3	20,621.9	20,990.9	453.7	66,683.0	357.1	225.9	912.8	1,452.3	1,795.2	33.4	4,776.6	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-13: 1991 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

Fuel Type	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	23.0	118.0	1,631.6	NE	16,208.3	7.7	17,988.7	2.2	11.1	151.9	NE	1,511.8	0.7	1,677.6
Residential Coal	23.0						23.0	2.2						2.2
Commercial Coal		118.0					118.0		11.1					11.1
Industrial Coking Coal			10.1				10.1			1.1				1.1
Industrial Other Coal			1,611.5				1,611.5			149.7				149.7
Coke Imports			10.0				10.0			1.0				1.0
Transportation Coal				NE										NE
Utility Coal					16,208.3		16,208.3					1,511.8		1,511.8
U.S. Territory Coal (bit)						7.7	7.7						0.7	0.7
Natural Gas	4,697.0	2,813.0	8,002.3	620.0	3,399.1	-	19,531.4	248.0	148.5	422.5	32.7	179.4		1,031.1
Total Petroleum	1,392.2	905.2	4,135.1	19,589.9	1,206.1	425.4	27,653.9	97.0	66.0	295.3	1,388.4	94.3	31.0	1,971.9
Asphalt & Road Oil														
Aviation Gasoline				41.7			41.7				2.9			2.9
Distillate Fuel Oil	930.4	517.4	1,063.8	3,451.3	83.6	71.4	6,117.7	67.4	37.5	77.0	249.9	6.1	5.2	443.0
Jet Fuel				2,364.4			2,442.6				166.5		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	632.8	19.9		13.8	1,124.7	24.5	4.3	39.7	1.3		0.9	70.6
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	1,094.9	134.6	1,946.8		17.3	21.1	17.5	85.4	10.5	151.9
Other Petroleum														
AvGas Blend Components			(0.1)				(0.1)			(0.0)				(0.0)
Crude Oil			38.9				38.9			2.9				2.9
MoGas Blend Components			(25.9)				(25.9)			(1.8)				(1.8)
Misc. Products														
Naphtha (<401 deg. F)			52.6				52.6			3.5				3.5
Other Oil (>401 deg. F)			132.4				132.4			9.6				9.6
Pentanes Plus			257.0				257.0			17.0				17.0
Petroleum Coke			539.6		27.6		567.2			54.6		2.8		57.3
Still Gas			1,404.3				1,404.3			89.3				89.3
Special Naphtha			14.1				14.1			1.0				1.0
Unfinished Oils			(450.1)				(450.1)			(33.0)				(33.0)
Waxes														
Geothermal					54.9		54.9					0.4		0.4
TOTAL (All Fuels)	6,112.2	3,836.2	13,769.1	20,209.9	20,868.4	433.2	65,229.0	347.1	225.6	869.6	1,421.1	1,785.9	31.7	4,681.1

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-14: 1990 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	26.0	129.0	1,643.1	NE	16,229.7	7.0	18,034.8	2.4	12.1	152.6	NE	1,513.0	0.6	1,680.9	
Residential Coal	26.0						26.0	2.4						2.4	
Commercial Coal		129.0					129.0		12.1					12.1	
Industrial Coking Coal			0.5				0.5			0.1				0.1	
Industrial Other Coal			1,637.6				1,637.6			152.1				152.1	
Coke Imports			5.0				5.0			0.5				0.5	
Transportation Coal				NE										NE	
Utility Coal					16,229.7		16,229.7					1,513.0		1,513.0	
U.S. Territory Coal (bit)						7.0	7.0						0.6	0.6	
Natural Gas	4,523.0	2,701.0	7,885.9	680.0	3,333.0	-	19,122.9	238.8	142.6	416.3	35.9	176.0		1,009.5	
Total Petroleum	1,407.0	953.1	4,382.4	19,900.3	1,292.6	374.8	28,310.3	98.3	69.5	313.9	1,410.9	101.0	27.4	2,020.9	
Asphalt & Road Oil															
Aviation Gasoline				45.0			45.0				3.1			3.1	
Distillate Fuel Oil	978.1	535.8	1,136.4	3,503.1	96.5	74.0	6,324.0	70.8	38.8	82.3	253.7	7.0	5.4	458.0	
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	606.0	21.6		14.4	1,071.4	22.9	4.0	38.1	1.4		0.9	67.3	
Lubricants															
Motor Gasoline		111.2	185.2	13,557.2		101.0	13,954.7		7.8	13.0	955.2		7.1	983.2	
Residual Fuel		229.8	364.1	300.3	1,167.3	121.8	2,183.5		17.9	28.4	23.4	91.1	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)			53.6				53.6			3.5				3.5	
Other Oil (>401 deg. F)			105.6				105.6			7.7				7.7	
Pentanes Plus			180.5				180.5			12.0				12.0	
Petroleum Coke			535.5		28.8		564.3			54.1		2.9		57.0	
Still Gas			1,452.4				1,452.4			92.3				92.3	
Special Naphtha			15.1				15.1			1.1				1.1	
Unfinished Oils			(369.1)				(369.1)			(27.0)				(27.0)	
Waxes															
Geothermal					52.9		52.9					0.4		0.4	
TOTAL (All Fuels)	5,956.0	3,783.1	13,911.4	20,580.3	20,908.2	381.9	65,521.0	339.6	224.2	882.8	1,446.8	1,790.3	28.0	4,711.7	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table 2-15), and international bunker fuel consumption (see Table 2-16).

^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 2-15: Non-Energy Fuel Consumption (TBtu)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Industry	3,993.2	3,937.3	4,080.2	4,195.6	4,546.2	4,561.0	4,644.3	4,794.6	5,127.6	5,398.1	4,985.1	4,933.3	5,016.4	5,023.4
Industrial Coking Coal	20.5	18.4	24.9	29.0	28.3	29.7	28.8	27.6	15.4	6.3	14.8	23.7	7.0	3.0
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
Natural Gas to Chemical Plants, Other Uses	244.1	234.6	212.4	239.0	302.4	305.3	310.1	323.7	376.3	390.3	388.9	394.0	402.0	401.0
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	1,217.4
LPG	1,001.9	1,116.5	1,174.1	1,139.9	1,352.6	1,389.2	1,455.9	1,440.9	1,568.1	1,651.2	1,497.2	1,483.9	1,550.4	1,478.4
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	160.8
Pentanes Plus	69.9	36.9	52.7	236.2	228.1	268.4	281.7	260.9	185.2	239.0	214.7	193.2	164.6	162.4
Naphtha (<401 deg. F)	294.3	246.3	322.8	299.8	352.0	329.5	426.1	467.8	529.1	458.6	556.5	473.2	559.5	588.4
Other Oil (>401 deg. F)	615.4	676.3	622.1	618.5	614.1	571.4	504.6	608.8	593.8	619.5	515.5	506.1	460.9	530.0
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	133.0
Petroleum Coke	90.7	65.9	143.0	40.4	56.3	51.3	63.4	29.9	124.7	193.9	53.9	132.8	113.6	90.9
Special Naphtha	92.1	73.8	90.8	90.7	72.4	63.3	67.0	63.8	98.1	133.9	89.1	75.5	98.7	77.5
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
Waxes	33.3	35.1	37.3	40.0	40.6	40.6	48.6	43.7	42.4	37.4	33.1	36.3	32.2	31.0
Miscellaneous Products	137.9	152.6	100.1	94.7	105.9	97.0	89.0	97.8	119.0	111.9	119.3	124.9	134.2	126.0
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	151.8
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	151.8
U.S. Territories	86.7	114.4	62.6	74.3	54.9	58.8	79.3	92.5	94.8	114.5	165.5	80.3	80.6	88.7
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	0.0	0.0
Other Petroleum (Misc. Prod.)	86.0	113.8	61.2	71.0	53.0	56.8	78.5	90.0	93.5	113.1	149.1	80.3	80.5	88.7
Total	4,255.9	4,209.1	4,303.3	4,433.3	4,771.9	4,787.7	4,886.6	5,059.3	5,402.5	5,694.6	5,330.0	5,177.9	5,259.4	5,263.9

Note: These values have been adjusted to account for petroleum feedstock exports and processes accounted for in the Industrial Processes Chapter.

Table 2-16: International Bunker Fuel Consumption (TBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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
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
Aviation Jet Fuel	656.5	660.6	666.4	675.1	683.9	723.0	743.7	796.6	807.4	838.9	862.8	846.3	880.5	848.7
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	1,442.2	1,392.7	1,344.8	1,240.7	1,170.5

Table 2-17: 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
Coke Imports	27.85	0.99
Utility 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 2-18).

Table 2-18: 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
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
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
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
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
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
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
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	19.34	19.34
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
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	19.34	19.34
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	20.23	20.23
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	20.23	20.23
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	20.23	20.23

Source: EIA (2004b)

Table 2-19: 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
Residential	924	955	936	995	1,008	1,043	1,083	1,076	1,130	1,145	1,192	1,203	1,267	1,280
Commercial	838	855	850	885	913	953	980	1,027	1,078	1,104	1,159	1,197	1,218	1,223
Industrial	1,060	1,065	1,095	1,105	1,142	1,157	1,179	1,187	1,212	1,241	1,248	1,139	1,150	1,167
Transportation	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total	2,827	2,880	2,886	2,989	3,069	3,157	3,247	3,294	3,425	3,495	3,605	3,544	3,641	3,675

Note: Does not include the U.S. territories.

Source: EIA (2004a)

2.2. Methodology for Estimating the Carbon Content of Fossil Fuels

This annex 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 2-20.

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

Table 2-20: 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
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
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
Industrial Coking Coal ^a	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00
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
Utility Coal ^{ab}	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
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
Petroleum														
Asphalt and Road Oil														
Oil	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62
Aviation Gasoline	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Distillate Fuel Oil	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Jet Fuel ^a	19.40	19.40	19.39	19.37	19.35	19.34	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33
Kerosene	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72
LPG (energy use) ^a	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.23	17.25	17.20	17.21	17.20	17.21
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
Lubricants	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24
Motor Gasoline ^a	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.34	19.34
Residual Fuel	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49
Other Petroleum														
Av Gas Blend														
Comp.	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Mo Gas Blend														
Comp ^a	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.34	19.34
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	20.23	20.23
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	20.23	20.23
Misc. Products (Terr.)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00

Naphtha (<401 deg. F)	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14
Other oil (>401 deg. F)	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Pentanes Plus	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24
Petrochemical Feed.	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37
Petroleum Coke	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85
Still Gas	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51
Special Naphtha	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86
Unfinished Oils ^a	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.23	20.23
Waxes	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81
Other Wax and Misc.	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81
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

^aCarbon contents vary annually based on changes in fuel composition.

^bCarbon content for utility coal used in the electric power calculations.

All coefficients based on higher heating value.¹

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 2-21.²

Table 2-21: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (Tg/QBtu) (1990-2003)

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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
Industrial Coking	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00
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
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
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 ^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 ^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 ^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 ^p

^p Preliminary

Sources: Carbon content coefficients by consuming sector from EIA (2004a). Carbon content coefficients by coal rank from USGS (1998) and SAIC (2004).

Methodology

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

¹ 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.

² 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.

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.

$$C_{\text{sector}} = \sum S_{\text{rank1}} * C_{\text{rank1}} + S_{\text{rank2}} * C_{\text{rank2}} + \dots + S_{\text{rank50}} * C_{\text{rank50}}$$

Where:

C_{sector} is the carbon content by consuming sector;

S_{rank} is the portion of consuming sector coal consumption attributed to a given rank in each state; and

C_{rank} is the estimated carbon content of a given rank in each state.

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.

$$N_{\text{rank}} = \sum P_{\text{rank1}} * C_{\text{rank1}} + P_{\text{rank2}} * C_{\text{rank2}} + \dots + P_{\text{rankn}} * C_{\text{rankn}}$$

Where:

N_{rank} is the national carbon content by rank;

P_{rank} is the portion of U.S. coal production attributed to a given rank in each state; and

C_{rank} is 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 the U.S. Geological Survey, CoalQual Database Version 2.0 (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's *Coal Industry Annual* (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 2-22).

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 2-22: 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

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 (C₂H₆), propane (C₃H₈), butane (C₄H₁₀), and, to a lesser extent, pentane (C₅H₁₂) and hexane (C₆H₁₄). 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 gasoline³ 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.

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.

³ 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.

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 2-23.

Table 2-23: 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 2-24.

Table 2-24: 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 (formerly Gas Research Institute) database (1992) as documented in W.E. Liss, W.H. Thrasher, G.F. Steinmetz, P. Chowdiah, and A. Atari, *Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States*.

Average heat content of natural gas consumed in the United States was taken from Table A4 of EIA's *Monthly Energy Review* (2004a).

Data on the average heat content consumed, on a state-by-state basis, was obtained from the U.S. Department of Energy, U.S. Energy Information Administration, *State Energy Data 2001: Consumption*, (2004b). Available online at <www.eia.doe.gov/emeu/states/_use_multistate.html>.

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 2-1 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 2-1: 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 2-1).

For the full sample (N=6,743), the average carbon content of a cubic foot of gas was 14.51 Tg/QBtu (see Table 2-24). 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.⁴

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.

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

Where:

C_{fuel} is the carbon content coefficient of the fuel;

D_{fuel} is the density of the fuel;

S_{fuel} is the share of the fuel that is carbon; and

E_{fuel} is 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).⁵ This is a range in density of 60 to 150 kilograms per barrel, or ± 50 percent. The variation in

⁴ 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.

⁵ 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

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.

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 2-2 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 2-2: 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.

lighter the compound. Light crude oils generally exceed 38 degrees API and heavy crude oils are all crude oils with an API gravity of 22 degrees or below. Intermediate crude oils fall in the range of 22 degrees to 38 degrees API gravity. API gravity can be calculated with the following formula: $\text{API Gravity} = (141.5/\text{Specific Gravity}) - 131.5$. Specific gravity is the density of a material relative to that of water. At standard temperature and pressure, there are 62.36 pounds of water per cubic foot, or 8.337 pounds water per gallon.

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 2-3).

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 2-3)

Polynuclear Aromatics. Polynuclear aromatics are large molecules with a multiple ring structure and few hydrogen atoms, such as naphthalene ($C_{10}H_8$ and 94.4 percent carbon by mass) and anthracene ($C_{14}H_{10}$ and 97.7 percent carbon). They are relatively rare but do appear in heavier petroleum products.

Figure 2-3 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 2-3: 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 2-25. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

Table 2-25: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2003 Carbon Content (Tg/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.34	5.253	59.6	86.60
LPG(total)	16.99	a	a	a
LPG (energy use)	17.21	a	a	a
LPG (non-energy use)	16.84	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	20.23	5.800	30.5	85.49
Unfinished Oils	20.23	5.825	30.5	85.49
Miscellaneous Products	20.23	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 2-28.

^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 (2004a), and SAIC (2004).

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.⁶ "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

⁶ 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.

possible carbon and energy contents per barrel. Table 2-26 reflects changes in the density of gasoline over time and across grades of gasoline through 2003.

Table 2-26: Motor Gasoline Density, 1990 – 2003 (Degrees API)

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

Source: National Institute of Petroleum and Energy Research (1990 through 2004).

The density of motor gasoline increased across all grades through 1994, partly as a result of the leaded gasoline phase-out. In order to maintain the “anti-knock” quality and octane ratings of gasoline in the absence of lead, the portion of aromatic hydrocarbons used in gasoline increased. As discussed above, aromatic hydrocarbons have a lower ratio of hydrogen to 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 2-27.

Table 2-27: Characteristics of Major Reformulated Fuel Additives

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

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 2-27 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 was obtained from the National Institute for Petroleum and Energy Research, *Motor Gasolines, Summer* and *Motor Gasolines, Winter* (1990 through 2004).

Data on the characteristics of reformulated gasoline was taken from the American Petroleum Institute, *Alcohols and Ethers: A Technical Assessment of Their Applications as Fuels and Fuel Components*, API 4261 (1988).

Data on the carbon content of motor gasoline was obtained from the following:

- Mark DeLuchi, Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity, Volume 2, ANL/ESD/TM-22, Vol. 2 (November 1993), Appendix C, pp. C-1 to C-8.
- Ultimate analysis of one sample of shale-oil derived gasoline from Applied Systems Corp., Compilation of Oil Shale Test Results (April 1976), p. 3-2.
- Ultimate analysis of samples of three varieties of gasoline from C.C. Ward, "Petroleum and Other liquid Fuels," in Marks' Standard Handbook for Mechanical Engineers (1978), pp. 7-14.
- Ultimate analysis of one sample of gasoline from J.W. Rose and J.R. Cooper, Technical Data on Fuel, The British National Committee, World Energy Conference, London, England (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's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004).

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 2-3, 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, "Hydrogen Content as a Measure of the Combustion Performance of Hydrocarbon Fuels," in *Current Research in Petroleum Fuels*, Volume I (1977), p. 116.

Data on the density of naphtha-based jet fuel was taken from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985), p. 60.

Standard heat contents for kerosene- and naphtha- based jet fuels were adopted from EIA's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

Data on the carbon content and density of kerosene-based jet fuel was taken from O.J. Hadaller and A.M. Momentny, *The Characteristics of Future Fuels*, Part 1, "Conventional Heat Fuels" (September 1990), pp. 46-50.

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 the carbon contents and density was derived from four samples from C. T. Hare and R.L. Bradow, "Characterization of Heavy-Duty Diesel Gaseous and Particulate Emissions, and the Effects of Fuel Composition," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

Three samples from E.F. Funkenbush, D.G. Leddy, and J.H. Johnson, "The Organization of the Soluble Organic Fraction of Diesel Particulate Matter," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

One sample from R.L. Mason, "Developing Prediction Equations for Fuels and Lubricants," SAE Paper 811218, p.34 (1981).

One sample from C.T. Hare, K.J. Springer, and R.L. Bradow, "Fuel and Additive Effects on Diesel Particulate- Development and Demonstration of Methodology," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 179.

One Sample from F. Black and L. High, "Methodology for Determining Particulate and Gaseous Diesel Emissions," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

A standard heat content was adopted from EIA's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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 was derived from three samples of residual fuel from the Middle East and one sample from Texas. These data were found in F. Mosby, G.B. Hoekstra, T.A. Kleinhenz, and J.M. Sokra, "Pilot Plant Proves Resid Process," in *Chemistry of Petroleum Processing and Extraction* (1976), p.227.

Three samples of heavy fuel oils from J.P. Longwell, "Interface Between Fuels and Combustion," in *Fossil Fuel Combustion: A Sourcebook* (1991).

Three samples of heavy fuel oils from C.C. Ward, "Petroleum and Other Liquid Fuels," in *Marks' Standard Handbook for Mechanical Engineers* (1978), pp. 7-14.

Two samples of heavy fuel oils from, D.A. Vorum, "Fuel and Synthesis Gases from Gaseous and Liquid Hydrocarbons," in American Gas Association, *Gas Engineer's Handbook* (1974), p. 3/71.

One sample of heavy fuel oil from W. Rose and J.R. Cooper, *Technical Data on Fuel*, The British National Committee, World Energy Conference, London, England (1977).

Density of residual fuel consumed for electric power generation was obtained from EIA's *Cost and Quality of Fuels*, (2001). Available online at <www.eia.doe.gov/cneaf/electricity/cq/cq_sum.html>.

Density of residual fuel consumed in marine vessels from EIA's Petroleum Supply Division, *Btu Tax on Finished Petroleum Products* (1993) and National Institute for Petroleum and Energy Research's *Fuel Oil Surveys* (1992).

A standard heat content was adopted from EIA's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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, C₃H₈, 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 2-28 summarizes the physical characteristic of LPG.

Table 2-28: 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 ₂ H ₆	16.88	80.0	2.916	16.25
Propane	C ₃ H ₈	12.44	81.8	3.824	17.20
Isobutane	C ₄ H ₁₀	11.20	82.8	4.162	17.75
n-butane	C ₄ H 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 2-29.

Table 2-29: Consumption and Carbon Content Coefficients of Liquefied Petroleum Gases, 1990-2003

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

Sources: Fuel use of LPG based on data from EIA (1995 through 2004) and API (1990 through 2004). Non-fuel use of LPG from API (1990 through 2004). Carbon contents from EIA (2004a).

Data Sources

Data on carbon share, density, and heat content of LPG was obtained from V.B. Guthrie (ed.), *Characteristics of Compounds*, Petroleum Products Handbook, (1960), p.3-3.

Data on LPG consumption was based on data obtained from the American Petroleum Institute, Natural Gas Liquids and Liquefied Refinery Gas Survey (1990 through 2004) and from the U.S. Department of Energy, Energy Information Administration, *Petroleum Supply Annual* (1990 through 2004), which is available online at www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html.

Non-fuel use of LPG was obtained from the American Petroleum Institute, Natural Gas Liquids and Liquefied Refinery Gas Survey (1990 through 2004).

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.

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 D 910 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 American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

A standard heat content for aviation gas was adopted from EIA’s *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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 2-30 below shows the composition of those samples.

Table 2-30: 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

One still gas sample from American Gas Association, *Gas Engineer's Handbook* (1974), pp. 3/71, 3.87.

Three still gas samples from C.R. Guerra, K. Kelton, and D.C. Nielsen, *Natural Gas Supplementation with Refinery Gases and Hydrogen,* in Institute of Gas Technology, *New Fuels and Advances in Combustion Technologies* (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's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

The density of asphalt was determined by the American Society for Testing and Materials, in *ASTM and Other Specifications for Petroleum Products and Lubricants* (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's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

The density of asphalt was determined by the American Society for Testing and Materials in *ASTM and Other Specifications for Petroleum Products and Lubricants* (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 G.H. Unzelman, "A Sticky Point for Refiners: FCC Gasoline and the Complex Model," *Fuel Reformulation* (July/August 1992), p. 29.

A standard heat content for petrochemical feedstock was adopted from EIA's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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 S. W. Martin, "Petroleum Coke," in Virgil Guthrie (ed.), *Petroleum Processing Handbook* (1960), pp. 14-15.

The density of petroleum coke was taken from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

A standard heat content for petroleum coke was adopted from EIA's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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 2-31 below.

Table 2-31: 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's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail (2004a)*.

Density and aromatic contents were adopted from K. Boldt and B.R. Hall, *Significance of Tests for Petroleum Products*, American Society for Testing and Materials (1977), p. 30.

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 American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

Density of microcrystalline waxes was derived from 10 samples found in V. Guthrie (ed.), *Petroleum Products Handbook* (1960).

A standard heat content for petroleum waxes was adopted from EIA's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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:

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

Absent the term representing sulfur content, the equation had an R-squared of only 0.35.⁷ 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, *International Critical Tables of Numerical Data, Physics, Chemistry, and Technology* (1927).

A standard heat content for crude oil was adopted from the EIA's *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (2004a).

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

⁷ R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

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 2003. 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 2-32. The EIA Coal Analysis File was originally developed by the U.S. Bureau of Mines and contained over 60,000 coal samples obtained through numerous coal seams throughout the United States. Many of the samples were collected starting in the 1940s and 1950s through the 1980s and analyzed in U.S. government laboratories. The updated sample set included 6,588 coal samples collected by the U.S. Geological Survey between 1973 and 1989.

Table 2-32: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank , 1990-2003 [Tg/QBtu]

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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
Industrial Coking	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00
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
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
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 ^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 ^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 ^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 ^P

^P (Preliminary)

Sources: Carbon content coefficients by consuming sector from EIA (2004a). Carbon content coefficients by coal rank from USGS (1998) and SAIC (2004).

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 Momeny 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.

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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 2-33. This Annex explains the methods and data sources employed in developing the storage factors for petrochemical feedstocks (industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha), asphalt and road oil, lubricants, waxes, and miscellaneous products. The storage 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 2-33: Fuel Types and Percent of Carbon Stored for Non-Energy Uses

Sector/Fuel Type	Storage Factor (%)
Industry	-
Industrial Coking Coal	0.75
Industrial Other Coal	0.65
Natural Gas to Chemical Plants	0.65
Asphalt & Road Oil	1.00
LPG	0.65
Lubricants	0.09
Pentanes Plus	0.65
Naphtha (<401 deg. F)	0.65
Other Oil (>401 deg. F)	0.65
Still Gas	0.65
Petroleum Coke	0.50
Special Naphtha	0.65
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 2003. 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 selected 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 – other industrial 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 methane, CH₄) to heavier, more complex naphthas and other oils.¹

After adjustments for (1) use in industrial processes and (2) net exports, the eight fuel categories constituted approximately 216.6 Tg CO₂ Eq., or 60 percent, of the 360.5 Tg CO₂ Eq. of non-energy fuel consumption in 2003. For 2003 the storage factor for the seven fuel categories was 65 percent. In other words, of the net consumption, 65 percent was destined for long-term storage in products—including products subsequently combusted for waste disposal—while the remaining 35 percent was emitted to the atmosphere directly as CO₂ (e.g., through combustion of industrial byproducts) or indirectly as CO₂ precursors (e.g., through evaporative product use). The indirect emissions include a variety of organic gases such as volatile organic compounds (VOCs) and carbon monoxide (CO), which eventually oxidize into CO₂ in the atmosphere. The derivation of the storage factor is described in the following sections.

Methodology and Data Sources

The petrochemical feedstocks storage factor is equal to the ratio of 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 2001c) 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, polypropylene resins), 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 2003.

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 trade statistics published by the U.S. Bureau of the Census (BoC). 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

¹ 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* included in the totals, however, as these commodities are petrochemicals produced from fossil fuels for export, and deplete domestic petrochemical feedstocks. Imports and exports of commodities for which production and consumption data are provided by EIA (e.g., butane, ethylene, liquefied petroleum gases) are also not included in the totals, to avoid double counting.

The BoC trade statistics are publicly available² and cover a complete time series from 1990 to 2001. 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 2-34. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2003 period.

Table 2-34: Net Exports of Petrochemical Feedstocks, 1990 – 2003 (Tg CO₂ Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002*	2003*
Net Exports	28.7	34.5	29.1	31.1	27.0	26.9	26.3	32.6	24.3	22.9	23.5	9.5	9.5	9.5

* Data for 2002 and 2003 were not yet available, so they were held constant at the 2001 value

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 2-34) 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 (NMVOC) emissions, hazardous waste incineration, industrial toxic chemical (i.e., TRI) releases, pesticides, and refinery wastewater discharges.³

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

² See the U.S International Trade Commission (USITC) Trade Dataweb at <<http://dataweb.usitc.gov/>>.

³ 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.

consumption (the inputs to the system) for some years in the time series.⁴ 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 CO₂ 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 2-35. Summing the carbon stored and dividing it by total carbon outputs yields the overall storage factor, as shown in the following equation for 2003:

$$\text{Overall Storage Factor} = \text{Carbon Stored} / (\text{Carbon Stored} + \text{Carbon Emitted}) = \\ 145.0 \text{ Tg CO}_2 \text{ Eq.} / (145.0 + 77.8) \text{ Tg CO}_2 \text{ Eq.} = 65 \%$$

Table 2-35: Carbon Stored and Emitted by Products from Feedstocks in 2003 (Tg CO₂ Eq.)

Product/Waste Type	Carbon Stored (Tg CO ₂ Eq.)	Carbon Emitted (Tg CO ₂ Eq.)
Industrial Releases	0.1	5.4
<i>TRI Releases</i>	<i>0.1</i>	<i>1.0</i>
<i>Industrial VOCs</i>	-	<i>2.0</i>
<i>Non-combustion CO</i>	-	<i>0.9</i>
<i>Refinery wastewater</i>	-	<i>0.1</i>
<i>Hazardous Waste Incin.</i>	-	<i>1.4</i>
Energy Recovery	-	58.1
Products	144.9	13.6
<i>Plastics</i>	<i>123.1</i>	-
<i>Synthetic Rubber</i>	<i>10.9</i>	-
<i>Abraded tire rubber</i>	-	<i>0.7</i>
<i>Synthetic Fiber</i>	<i>10.6</i>	-
<i>Pesticides</i>	<i>0.3</i>	<i>0.2</i>
<i>Soaps, shampoos, detergents</i>	-	<i>4.9</i>
<i>Solvent VOCs</i>	-	<i>8.5</i>
Total	145.0	77.8

- 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.

Industrial Releases

Industrial releases include toxics reported through the Toxics Release Inventory, industrial emissions of volatile organic compounds (VOCs), carbon monoxide emissions (other than those related to fuel combustion), treatment of refinery wastewater, and 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

⁴ Overall, there was fairly close agreement between inputs and outputs; for the entire 1990 – 2003 time series, outputs exceeded inputs by 0.2 percent. During the period 1993 – 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.

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.”⁵ The carbon released in each disposal location is provided in Table 2-36.

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 CO₂ (i.e., a storage factor of zero was applied to these categories.) The release allocation is not reported for off-site releases; therefore, the approach was to develop a 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 2003 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 2-36: 1998 TRI Releases by Disposal Location (Gg CO₂ 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 2004). The 1990-2003 Trends Report data include information on NMVOC emissions by end-use category; some of these fall into the heading of “industrial releases” in Table 2-35 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, 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

⁵ 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).

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 2-37 for 1990 through 2003. Solvent evaporation emissions in 2003 were 8.5 Tg CO₂ Eq., and industrial NMVOC emissions in 2003 were 2.0 Tg CO₂ Eq. In 2004, NMVOC and solvent activity data were revised across the entire time series to reflect updated information from the 2003 National Air Quality and Emissions Trends Report.

Table 2-37: Industrial and Solvent NMVOC Emissions

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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	702
Carbon Content (%)	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
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	4,562
Carbon Content (%)	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	8.5

^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 2003 National Air Quality and Emissions Trends Report (EPA 2004). There are four 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 CO₂) emissions from oil and gas production 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 2-38 lists the CO emissions that remain after taking into account the exclusions listed above.

Table 2-38: Non-Combustion Carbon Monoxide Emissions^a

	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	656	0.9

^a Includes emissions from chemical and allied products, petroleum and related industries, metals processing, and other industrial processes categories.

Refinery Wastewater

Carbon flows associated with the treatment and discharge of refinery wastewater are included in the mass balance. To develop an estimate of annual emissions associated with the wastewater, it was assumed that the average concentration of Total Organic Carbon in refinery effluents was 10.5 mg/L, based on 1992 data reported in EPA's Permit Compliance System. It was also assumed that (a) the overall treatment efficiency (excluding recycling of oil back to the refinery) was 90 percent, (b) average flow is about 1 million gallons per day (3,800 m³/day), there are 192 operating refineries in the United States, (c) the majority of organic compounds in refinery wastewater are not covered by the TRI requirements (and thus there is no significant double-counting of releases with the TRI estimate), and (d) all of the carbon in the raw wastewater is destined for emission as CO₂. Based on these assumptions, annual emissions are roughly 0.1 Tg CO₂ Eq. Note that fugitive air emissions of methane from treatment of refinery wastewater are already accounted for in the Inventory in the category of "Petroleum Systems," but other fugitive air emissions and discharges of wastewater to surface water or publicly owned treatment works are not included elsewhere in the Inventory. More recent data on refinery effluents has not been found, and thus the entire time series has been assumed to have the same value as 1992.

Hazardous Waste Incineration

Hazardous wastes are defined by the EPA under the Resource Conservation and Recovery Act (RCRA).⁶ 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 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.

⁶ [42 U.S.C. §6924, SDWA §3004]

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 2-39). Regulations require incinerators to achieve at least 99.99 percent destruction of organics; this formed the basis for assuming the fraction of carbon oxidized.

Table 2-39: 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

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, and 1998 (EIA 1994, 1997, 2001b). 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 2-41). The conversion factors listed in Annex 2.1 were used to convert the Btu values for each fuel feedstock to Tg CO₂. Petrochemical feedstocks combusted for energy recovery corresponded to 42.2 Tg CO₂ Eq. in 1991, 35.4 Tg CO₂ Eq. in 1994, and 58.1 Tg CO₂ Eq. in 1998. Values for petrochemical feedstocks burned for energy recovery for years between 1991 and 1994 and between 1994 and 1998 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 1998 are assumed to be the same as the value for 1998 (Table 2-40).

Table 2-40: Carbon Emitted from Fuels Burned for Energy Recovery (Tg CO₂ Eq)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Emissions	42.2	42.2	40.0	37.7	35.4	41.1	46.8	52.4	58.1	58.1	58.1	58.1	58.1	58.1

Table 2-41: Summary of 1998 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	1	0	0	1
Petroleum and Coal Products	324	0	1	1399	93	231
Chemicals	325	416	16	0	194	118
Plastics and Rubber Products	326	0	0	0	5	0
Nonmetallic Mineral Products	327	2	9	0	0	14
Primary Metals	331	2	2	0	17	5
Fabricated Metal Products	332	1	0	0	2	4
Machinery	333	0	1	0	1	2
Computer and Electronic Products	334	0	0	0	1	0
Electrical Equip., Appliances, Components	335	1	1	0	2	0
Transportation Equipment	336	1	2	0	7	19
Miscellaneous	337	0	0	0	0	2
Total (Trillion Btu)		423	33	1399	323	395
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)		7.60	0.67	24.25		7.58
Total Carbon (Tg) (exc still gas from refining)		7.60	0.67	0.00		7.58

^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

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; 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; SPI 2000; Eldredge-Roebuck 2000). These data were organized by year and resin type (see Table 2-42). 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 2-43 and Table 2-44. 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 65 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 2-42: 2003 Plastic Resin Production (Tg dry weight) and Carbon Stored (Tg CO₂ Eq)

Resin Type	2003 Production ^a (Tg dry weight)	Carbon Stored (Tg CO ₂ Eq.)
Epoxy	0.27	0.7
Urea	0.68	0.9
Melamine	0.68	0.7
Phenolic	1.90	5.3
Low-Density Polyethylene (LDPE)	3.35	10.5
Linear Low-Density Polyethylene (LLDPE)	4.77	15.0
High Density Polyethylene (HDPE)	6.70	21.1
Polypropylene (PP)	7.50	23.6
Acrylonitrile-butadiene-styrene (ABS)	0.50	1.6
Styrene-acrylonitrile (SAN)	0.06	0.2
Other Styrenics	0.66	2.2
Polystyrene (PS)	2.75	9.3
Nylon	0.53	1.3
Polyvinyl chloride (PVC) ^b	6.28	8.8
Thermoplastic Polyester	3.13	7.2
Engineering Resins	1.12	2.7
All Other (including Polyester (unsaturated))	4.95	12.0
Total	45.83	123.1

^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 2-43: 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 2-44)
Polyvinyl Chloride (PVC)	38%	Polyvinyl chloride
Thermoplastic Polyester	63%	Polyethylene terephthalate
Engineering Resins	66%	Weighted average of other resin production
All Other	66%	Weighted average of other resin production

*Does not include alcoholic hydrogens.

Table 2-44: 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 2001* (RMA 2002), 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 2002 and 2003, so tire consumption for these years was assumed to equal 2001 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, 1998a, 1999a, 2000c,d, 2001a, 2002b, and 2003). 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% for tire synthetic rubber and 85% 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 (see Table 2-45). 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 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 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 2-45: 1998 Rubber Consumption (Gg) and Carbon Content (%)

Elastomer Type	1998 Consumption (Gg)*	Carbon Content
SBR Solid	908	91%
Polybutadiene	561	89%
Ethylene Propylene	320	86%
Polychloroprene	69	59%
NBR Solid	87	77%
Polyisoprene	78	88%
Others	369	88%
Weighted Average	-	90%
Total	2,392	-

* 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). These data are organized by year and fiber type. For each fiber, a carbon content was assigned based on molecular formula (see Table 2-46). 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 2-46: 2003* Fiber Production (Tg), Carbon Content (%), and Carbon Stored (Tg CO₂ Eq.)

Fiber Type	Production (Tg)	Carbon Content	Carbon Stored (Tg CO ₂ Eq.)
Polyester	1.5	63%	3.4

Nylon	1.1	64%	2.6
Olefin	1.4	86%	4.2
Acrylic	0.2	68%	0.4
Total	4.1	-	10.6

* 2003 production data were not available yet, so these values are set equal to 2002 production

- 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 2000—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 2-47: Active Ingredient Consumption in Pesticides (Million lbs.) and Carbon Emitted and Stored (Tg CO₂ 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 CO₂ Eq.

^a1999 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 1997 Economic Census. Due to resource constraints, and the small mass of carbon in this category, the year 1997 was taken to be representative of the entire time series.

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 liquid⁷ 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 CO₂ Eq. in cleansers.

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 2003. 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 moderate relative error of ± 35 percent, in part, due to assumptions relating to the feedstock exporting. The greatest uncertainty range, ± 45 and an associated standard deviation of 121.7 TBtu, was applied to the production of other oils (>401 deg. F). A narrow uniform distribution was applied to each carbon coefficient.

The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve around a mean of 64.9 percent, with a standard deviation of 1 percent and 95 percent confidence limits of 63 percent and 67 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 75.45 Tg CO₂ Eq., standard deviation of 2.0 Tg CO₂ Eq., and 95 percent confidence limits of 61.0 and 90.5 Tg CO₂ Eq. This compares with a calculated estimate of 75.26 Tg CO₂ Eq. The uncertainty emission distribution does not currently capture additional emissions from industrial other coal, which constitutes less than 0.5 Tg CO₂ 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 five fates that result in long-term storage (e.g., plastics production), and ten that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all 15 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 CO₂ 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.

⁷ A density of 1.05 g/mL—slightly denser than water—was assumed for liquid cleansers.

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 2003). The list of commodities for which imports and exports were analyzed is not comprehensive in tracking fossil fuel-derived feedstocks and may underestimate 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 CO₂ 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, and 1998 (EIA 1994, 1997, 2001b). Data from the MECS conducted for calendar year 2002 and 2003 was not yet available. 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, delivery 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.

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, and TRI releases to underground injection and Subtitle C landfills is accounted for in the uncertainty estimate above. In the next two years 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 CO₂ 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.⁸ 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).

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 2003. 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% 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 99.5 percent, with a standard deviation of

⁸ The emission factors are expressed as a function of asphalt paving tonnage (i.e., including the rock aggregate as well as the asphalt cement).

0.2 percent and boundaries between 99.1 and 99.8 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 CO₂ is uncertain. Long-term studies may reveal higher lifetime emissions rates associated with degradation.

Many of the values used in the analysis are also uncertain and are based on estimates and professional judgment. For example, the asphalt cement input for hot mix asphalt was based on expert advice indicating that the range is variable—from about 3 to 5 percent—with actual content based on climate and geographical factors (Connolly 2000). Over this range, the effect on the calculated 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 (2004), the carbon content from U.S. production of lubricants in 2003 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 2003 were about 5.8 Tg C, or 21.1 Tg CO₂ Eq.

Methodology and Data Sources

For each lubricant category, a storage factor was derived by identifying disposal fates and applying assumptions as to the disposition of the 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 15 years.⁹ 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 2-48 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 CO₂ (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 CO₂ given that the releases are generally small and most of the oil is biodegraded (based on the observation that land farming—application to soil—is one of the most frequently used methods for degrading

⁹ 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.

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 CO₂, only about 3 percent of the carbon in oil lubricants goes into long-term storage.

Table 2-48: 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 2-49 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 2-49: Commercial and Environmental Fate of Grease Lubricants (Percent)

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 2003. 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 3.9 and 17.5 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 20.9 Tg CO₂, standard deviation of 0.5, and 95 percent confidence limits of 17.4 and 24.4 Tg CO₂. This compares with a calculated estimate of 21.2 Tg CO₂.

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 2-50 categorizes wax end uses identified by the NPRA, and lists each end use’s estimated carbon storage factor.

Table 2-50: 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 CO₂. In firelogs, petroleum wax is used as a binder and as a fuel, and is combusted during product use, likely resulting in the emission of nearly all carbon contained in product. Similarly, carbon contained in hotmelts is assumed to be emitted as CO₂ as heat is applied to these products during use. It is estimated that 50 percent of the 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 CO₂ from wax during the production of the product.) Wax is used in many different packaging materials including: wrappers, cartons, papers, paperboard, and corrugated products (NPRA 2002). Davie (1993) and Davie et al. (1995) suggest that wax coatings in packaging products degrade rapidly in an aerobic environment, producing CO₂; however, because packaging products ultimately enter landfills typically having an anaerobic environment, most of the 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 2003. 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 57.7 percent, with a standard deviation of 6.5 percent and 95 percent confidence limits of 44 percent and 69 percent. This compares to the calculated estimate, used in the *Inventory*, of 58 percent. The analysis produced an emission distribution approximating a normal curve with a mean of 1.1 Tg CO₂, standard deviation of 0.05 Tg CO₂, and 95 percent confidence limits of 0.72 and 1.46 Tg CO₂. This compares with a calculated estimate of 0.95 Tg CO₂. 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 2003 was 88.7 TBtu. One hundred percent of the carbon content is assumed to be emitted to the atmosphere, where it is oxidized to CO₂.

Uncertainty

A separate uncertainty analysis was not conducted for miscellaneous products, though this category was included in the uncertainty analysis of other non-energy uses discussed in the following section.

Other Non-Energy Uses

The remaining fuel types use storage factors that are not based on U.S.-specific analysis. For industrial coking coal and distillate fuel oil, storage factors were taken from 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.

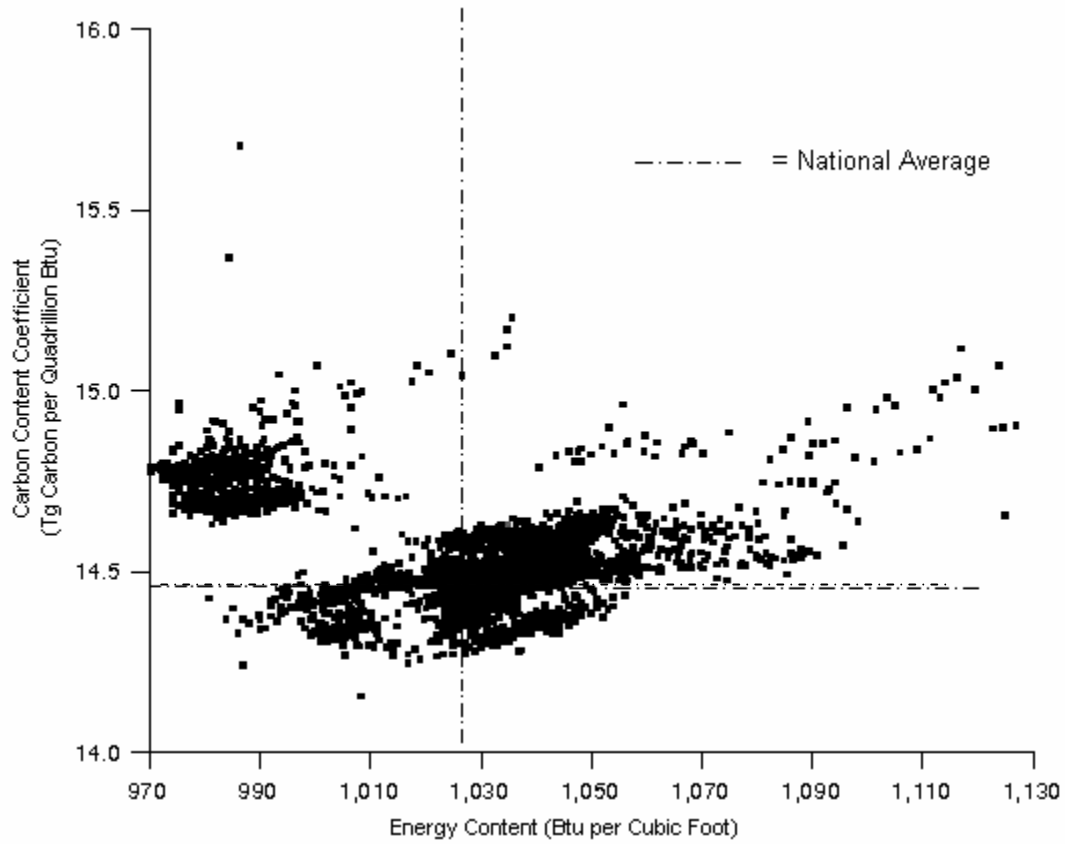
Uncertainty

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 2003. 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 41.1 percent, with a standard deviation of 12.4 percent and 95 percent confidence limits of 18 percent and 67 percent. This compares to the calculated, weighted average (across the various fuels) storage factor of 23.8 percent. The analysis produced an emission distribution approximating a normal curve with a mean of 16.2 Tg CO₂ and a

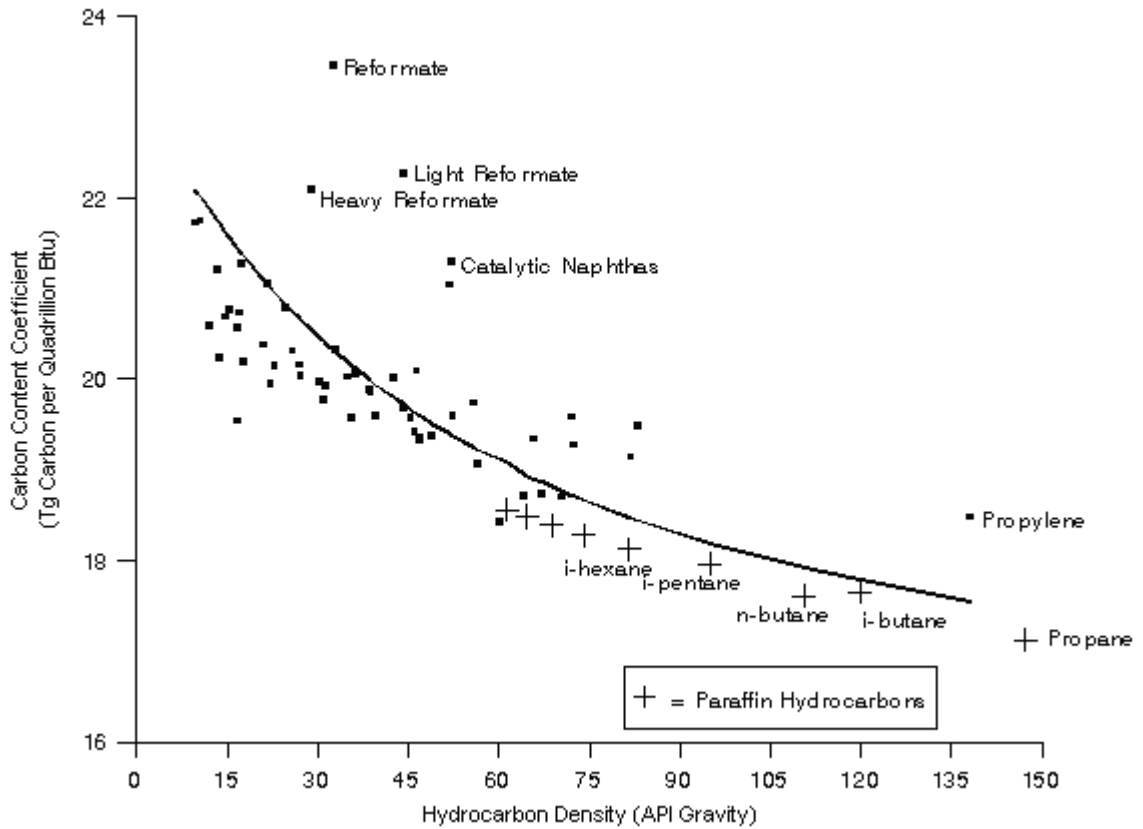
standard deviation of 1.0 Tg CO₂, and 95 percent confidence limits of 9.0 Tg CO₂ and 23.2 Tg CO₂. This compares with the Inventory estimate of 20.9 Tg CO₂, which falls closer to the upper boundary of the confidence limit. The uncertainty analysis results are driven primarily by the very broad uncertainty inputs for the storage factors.

Figure 2-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute Database



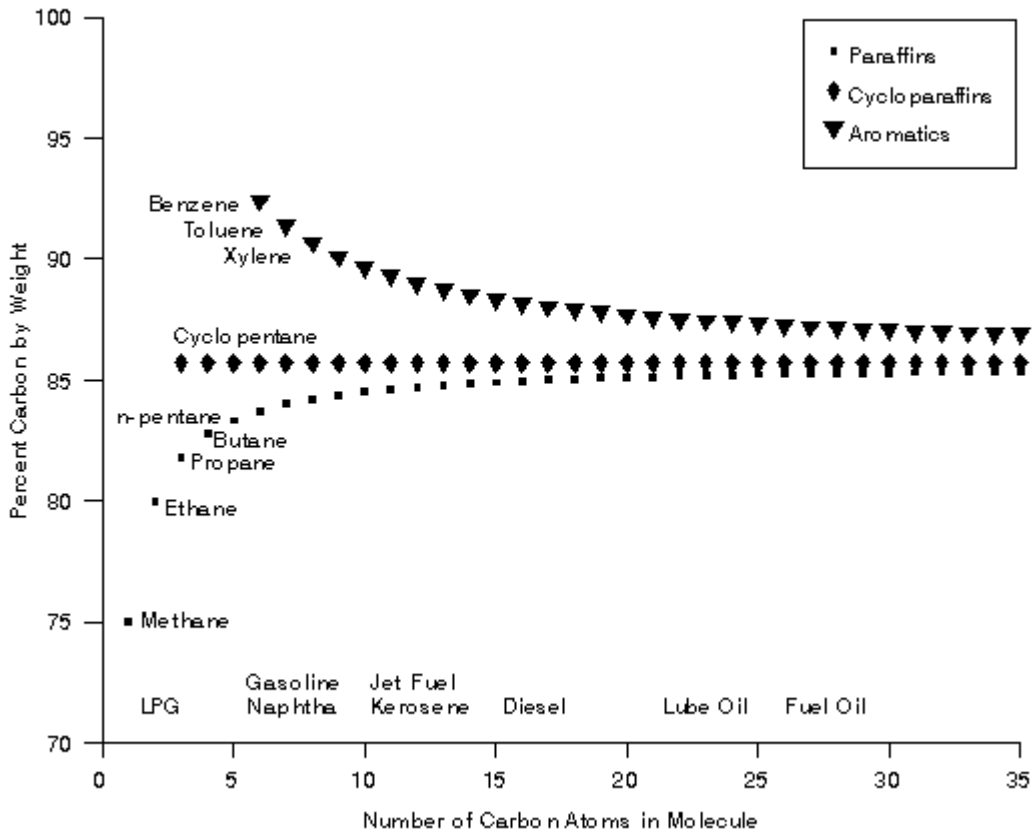
Source: EIA (1994) Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-1992, U.S. Department of Energy, Washington, DC, November, 1994, DOE/EIA 0573, Appendix A.

Figure 2-2: 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 2-3: Carbon Content of Pure Hydrocarbons as a Function of Carbon Number



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

ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories

3.1. Methodology for Estimating Emissions of CH₄, N₂O, and Ambient Air Pollutants from Stationary Combustion

Estimates of CH₄ and N₂O Emissions

Methane (CH₄) and nitrous oxide (N₂O) emissions from stationary combustion were estimated using IPCC emission factors and methods. Estimates were obtained by multiplying emission factors—by sector and fuel type—by fossil fuel and wood consumption data. This “top-down” methodology is characterized by two basic steps, described below. Data are presented in Table 3-1 through Table 3-5.

Step 1: Determine Energy Consumption by Sector and Fuel Type

Energy consumption from stationary combustion activities was grouped by sector: industrial, commercial, residential, electric power, and U.S. territories. For CH₄ and N₂O, estimates were based upon consumption of coal, gas, oil, and wood. Energy consumption data for the United States were obtained from EIA’s *Monthly Energy Review, July 2004 and Unpublished Supplemental Tables on Petroleum Product detail* (EIA 2004). 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 (2004).¹ Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.² Construction and agricultural fuel use was obtained from EPA (2004b). 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 3-1 provides annual energy consumption data for the years 1990 through 2003.

Step 2: Determine the Amount of CH₄ and N₂O Emitted

Activity data for each sector and fuel type were then multiplied by emission factors to obtain emission estimates. Emission factors for the residential, commercial, industrial, and electric power sectors were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). These N₂O emission factors by fuel type (consistent across sectors) were also assumed for U.S. territories. The CH₄ emission factors by fuel type for U.S. territories were estimated based on the emission factor for the primary sector in which each fuel was combusted. Table 3-2 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 2004a) 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 ambient air pollutants, the major source categories included coal, fuel oil, natural gas, wood, other fuels (i.e., bagasse, liquefied petroleum gases, coke, coke oven gas, and others), and stationary internal combustion, which

¹ U.S. territories data also include combustion from mobile activities because data to allocate territories’ energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

² 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.

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 3-3 through Table 3-5 present ambient air pollutant emission estimates for 1990 through 2003.

The basic calculation procedure for most source categories presented in EPA (2003) and EPA (2004a) 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 3-1: Fuel Consumption by Stationary Combustion for Calculating CH₄ and N₂O Emissions (Tbtu)

Fuel/End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Coal	18,043	17,997	18,161	18,885	18,972	19,126	20,048	20,547	20,722	20,741	21,677	20,969	21,116	21,552
Residential	26	23	24	24	21	17	17	16	13	14	12	12	11	12
Commercial	129	118	118	119	118	117	122	129	92	103	91	97	91	99
Industrial	1,651	1,640	1,609	1,622	1,653	1,615	1,576	1,585	1,500	1,443	1,456	1,411	1,325	1,333
Electric Power	16,230	16,208	16,402	17,111	17,170	17,367	18,323	18,807	19,107	19,171	20,108	19,439	19,677	20,068
U.S. Territories	7	8	9	10	10	10	10	10	11	10	10	10	13	40
Petroleum	6,949	6,541	6,704	6,478	6,551	5,920	6,433	6,442	6,312	6,487	6,711	7,346	6,923	7,403
Residential	1,407	1,392	1,427	1,448	1,420	1,383	1,488	1,428	1,314	1,473	1,563	1,539	1,519	1,546
Commercial	953	905	854	780	787	732	751	704	661	661	756	742	737	753
Industrial	2,921	2,612	2,980	2,660	2,774	2,552	2,893	2,892	2,539	2,651	2,767	3,157	3,091	3,209
Electric Power	1,293	1,206	997	1,130	1,063	757	821	931	1,312	1,217	1,151	1,275	953	1,198
U.S. Territories	375	425	445	460	507	496	481	487	486	485	473	634	624	698
Natural Gas	18,385	18,845	19,574	20,042	20,391	21,321	21,707	21,770	21,445	21,510	22,465	21,583	22,272	21,477
Residential	4,523	4,697	4,835	5,095	4,988	4,981	5,383	5,118	4,669	4,858	5,121	4,919	5,036	5,253
Commercial	2,701	2,813	2,890	2,942	2,979	3,113	3,244	3,302	3,098	3,130	3,265	3,116	3,196	3,233
Industrial	7,827	7,936	8,314	8,446	8,424	8,900	9,198	9,203	8,980	8,598	8,748	8,048	8,228	7,705
Electric Power	3,333	3,399	3,535	3,559	4,000	4,327	3,882	4,147	4,698	4,924	5,318	5,477	5,789	5,259
U.S. Territories	0	0	0	0	0	0	0	0	0	0	13	23	23	27
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	2,036	2,086
Residential	581	613	645	548	537	596	595	433	387	414	433	370	313	359
Commercial	39	41	44	46	46	46	50	49	48	52	53	40	42	42
Industrial	1,442	1,410	1,461	1,483	1,580	1,652	1,683	1,731	1,603	1,620	1,636	1,443	1,531	1,524
Electric Power	129	126	140	150	152	125	138	137	137	138	134	126	150	161
U.S. Territories	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 3-2: CH₄ and N₂O Emission Factors by Fuel Type and Sector (g/GJ)¹

Fuel/End-Use Sector	CH ₄	N ₂ O
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)

¹ GJ (Gigajoule) = 10⁹ joules. One joule = 9.486×10⁻⁴ Btu

Table 3-3: NO_x Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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	4,045
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	3,634	3,447
Fuel Oil	200	192	154	163	148	87	107	132	202	179	147	149	142	135
Natural gas	513	526	526	500	536	510	259	289	346	400	383	332	317	301
Other Fuels ^a	NA	NA	NA	NA	NA	NA	5	6	24	33	36	37	36	34
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Internal Combustion	213	152	159	160	159	134	142	150	149	141	140	140	134	127
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	2,516
Coal	530	517	521	534	546	541	490	487	475	475	484	518	539	522
Fuel Oil	240	215	222	222	219	224	203	196	190	190	166	153	160	154
Natural gas	1,072	1,134	1,180	1,207	1,210	1,202	1,092	1,079	1,066	880	902	914	952	920
Wood	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	116
Internal Combustion	792	720	748	783	767	774	965	948	933	813	809	798	830	803
Commercial	336	333	348	360	365	365	360	369	347	255	256	261	243	244
Coal	36	33	35	37	36	35	30	32	34	23	21	21	19	19
Fuel Oil	88	80	84	84	86	94	86	88	73	54	52	52	49	49
Natural gas	181	191	204	211	215	210	224	229	220	156	161	165	154	155
Wood	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
Residential	749	829	879	827	817	813	726	699	651	441	439	446	415	417
Coal ^b	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
Natural Gas ^b	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
Other Fuels ^a	708	784	831	787	777	769	699	671	624	416	417	424	395	397
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	7,523	7,222

NA (Not Applicable)

^a "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003), (EPA 2004a).^b Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003), (EPA 2004a).

Note: Totals may not sum due to independent rounding.

Table 3-4: CO Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Electric Power	329	317	318	329	335	338	369	385	409	450	439	439	451	480
Coal	213	212	214	224	224	227	228	233	220	187	221	220	226	240
Fuel Oil	18	17	14	15	13	9	11	13	17	36	27	28	28	30
Natural gas	46	46	47	45	48	49	72	76	88	151	96	92	95	101
Other Fuels ^a	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	NA	NA	NA	NA	NA	NA	7	8	30	24	31	32	33	35
Internal Combustion	52	41	43	46	50	52	52	54	54	52	63	67	69	73
Industrial	798	835	867	946	944	958	1,079	1,055	1,044	1,100	1,106	1,137	1,303	1,249
Coal	95	92	92	92	91	88	100	99	96	114	118	125	143	138
Fuel Oil	67	54	58	60	60	64	49	47	46	54	48	45	52	50
Natural gas	205	257	272	292	306	313	308	308	305	350	355	366	419	402
Wood	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	353
Internal Combustion	177	189	205	243	228	222	306	299	294	296	285	279	320	307
Commercial	205	196	204	207	212	211	122	126	122	151	151	154	124	149
Coal	13	13	13	14	13	14	13	13	14	16	14	13	11	13
Fuel Oil	16	16	16	16	16	17	17	18	15	17	17	17	14	17
Natural gas	40	40	46	48	49	49	58	59	57	81	83	84	68	82
Wood	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	37
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	2,575
Coal ^b	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
Natural Gas ^b	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	2,358
Other Fuels ^a	238	255	265	249	243	248	231	229	220	229	228	224	181	217
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	4,454

NA (Not Applicable)

^a "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003) , (EPA 2004a).

^b Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003) , (EPA 2004a).

Note: Totals may not sum due to independent rounding.

Table 3-5: NMVOC Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Electric Power	43	40	40	41	41	40	44	47	51	49	56	55	47	50
Coal	25	25	25	26	26	26	25	26	26	25	27	26	22	24
Fuel Oil	5	5	4	4	4	2	3	4	5	4	4	4	4	4
Natural gas	2	2	2	2	2	2	7	7	9	9	12	12	10	11
Other Fuels ^a	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	NA	NA	NA	NA	NA	NA	+	+	1	2	2	2	1	2
Internal Combustion	11	9	9	9	9	9	9	10	10	10	11	10	9	10
Industrial	165	177	169	169	178	187	163	160	159	156	157	159	155	154
Coal	7	5	7	5	7	5	6	6	6	9	9	10	10	10
Fuel Oil	11	10	11	11	11	11	8	7	7	10	9	9	8	8
Natural gas	52	54	47	46	57	66	54	54	54	52	53	54	52	52
Wood	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	28
Internal Combustion	49	61	60	60	58	59	63	62	61	60	58	57	55	55
Commercial	18	18	20	22	21	21	22	22	21	25	28	29	28	29
Coal	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
Natural gas	7	8	9	10	10	10	13	13	12	11	14	14	12	13
Wood	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	13	11
Residential	686	739	782	670	657	726	788	787	786	815	837	836	696	773
Coal ^b	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
Natural Gas ^b	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	748
Other Fuels ^a	35	35	36	36	36	37	33	32	30	21	27	27	23	25
Total	912	975	1,011	901	898	973	1,018	1,016	1,016	1,045	1,077	1,080	926	1,007

NA (Not Applicable)

^a "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003) , (EPA 2004a).

^b Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003), (EPA 2004a).

Note: Totals may not sum due to independent rounding.

3.2. Methodology for Estimating Emissions of CH₄, N₂O, and Ambient Air Pollutants from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related Greenhouse Gas Emissions

Estimates of CH₄ and N₂O Emissions

Greenhouse gas emissions from mobile combustion other than CO₂ are reported by transport mode (e.g., road, rail, aviation, and waterborne), vehicle type, and fuel type. Emission estimates for CH₄ and N₂O were derived using a methodology similar to that outlined in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Activity data were obtained from a number of U.S. government agencies and other publications. Depending on the category, these basic activity data included such information as fuel consumption and vehicle miles traveled (VMT).

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,¹ buses, and motorcycles) were obtained from the Federal Highway Administration's (FHWA) *Highway Statistics* (FHWA 1996 through 2004). As these vehicle categories are not fuel-specific, VMT for each vehicle type was disaggregated by fuel type so that the appropriate emission factors could be applied. First, fuel consumption (in gallons) by vehicle type from *Highway Statistics* Table VM-1 (FHWA, 1996 through 2004) was allocated to fuel types (gasoline, diesel, other) using historical data on 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 resulting fuel consumption figures by fuel type were then scaled so that the total gasoline and diesel fuel consumption would match the totals reported in *Highway Statistics*, Table MF-21. VMT for each vehicle category was then allocated to each fuel type based on the share of fuel consumption for that vehicle category.

VMT for alternative fuel vehicles (AFVs) were calculated separately, and the methodology is explained in the following section on AFVs. Since the VMT estimates from FHWA include total VMT in the United States, VMT from AFVs from this total was subtracted.² National VMT estimates for gasoline and diesel highway vehicles are presented in Table 3-6 and Table 3-7, 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 3-17 through Table 3-22. This distribution was derived by weighting the appropriate age distribution of the U.S. vehicle fleet according to vehicle registrations (Table 3-10 through Table 3-14) by the average annual age-specific vehicle mileage accumulation of U.S. vehicles (Table 3-16). 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 2004b).³ Age-specific vehicle mileage accumulation was obtained from EPA's MOBILE6 model (EPA 2000).

¹ 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 3-9, which provides VMT data for medium-duty alternative fuel vehicles.

² In previous years' Inventories, gasoline- and diesel-electric hybrid vehicles were considered part of the "alternative fuel and advanced technology" category. Since these vehicles are powered only by gas and diesel fuels, they have been excluded from the AFV classification.

³ Age distributions were held constant for the period 1990-1998, and reflect a 25-year vehicle age span. EPA (2004b) 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 3-24 through Table 3-27. 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).⁴

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 2004b). Vehicle classes and emission standard tiers to which each engine family was certified were taken from annual certification test results and data (EPA 2004a). 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 CH₄ and N₂O 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 CH₄ and N₂O Emitted by Vehicle, Fuel, and Control Technology Type

VMT for each highway category for each year were first converted to vehicle kilometers traveled (VKT) so that emission factors could be applied. Emissions of CH₄ and N₂O were then calculated by multiplying total VKT 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.⁵ The data obtained include vehicle fuel use and total number of vehicles

⁴ For further description, see “Definitions of Emission Control Technologies and Standards” section of this annex.

⁵ 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.

in use from 1992 through 2003. Because AFVs run on different fuel types, their fuel use characteristics are not directly comparable. Accordingly, fuel economy for each vehicle type is expressed in *gasoline equivalent* terms, i.e., how much gasoline contains the equivalent amount of energy as the alternative fuel. Energy economy ratios (the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles) were taken from full fuel cycle studies done for the California Air Resources Board (Unnasch and Browning, 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). Overall VMT estimates for AFVs are shown in Table 3-8, while more detailed estimates of VMT by control technology are shown in Table 3-9.

Step 2: Determine CH₄ and N₂O Emission Factors by Vehicle and Alternative Fuel Type

Limited data exist on N₂O and CH₄ 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 CH₄ emissions from actual test data and determine N₂O 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 N₂O 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 N₂O 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 N₂O ratio of EPA Tier 1 cars was used to determine the N₂O emissions from alternative fueled vehicles. Based upon gasoline data for EPA Tier 1 cars, the tailpipe NO_x to N₂O ratio is 5.75.⁶

Methane emission factors for light-duty vehicles were taken from the Auto/Oil Air Quality Improvement Research Program dataset (CRC 1997). This dataset provided CH₄ 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 CH₄ 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 N₂O ratio of 50, which is more typical for heavy-duty engines with oxidation catalysts. These emission factors are shown in Table 3-29.

Step 3: Determine the Amount of CH₄ and N₂O Emitted by Vehicle and Fuel Type

Emissions of CH₄ and N₂O were calculated by multiplying total VMT for each vehicle and fuel type (Step 1) by the appropriate emission factors (Step 2).

Methodology for Non-Highway Mobile Sources

Activity data for non-highway vehicles were based on annual fuel consumption statistics by transportation mode and fuel type and are shown in Table 3-23. Consumption data for ships and boats (i.e., vessel bunkering) were obtained from EIA (1991-2004, 2004, 2004) (for distillate fuel) and EIA (2004) (for residual fuel); marine transport fuel consumption data for U.S. territories (EIA 2002b, 2003-2004, and 1991-2004) were added to domestic consumption, and this total was reduced by the amount of fuel used for international bunkers.⁷ Annual diesel

⁶ Lipman and Delucchi (2002) found NO_x to N₂O ratios for light-duty alternative fuel vehicles with three-way catalyst systems to vary from 3 to 5.5 for older technology.

⁷ See International Bunker Fuels section of the Energy Chapter.

consumption for Class I railroad locomotives was obtained from AAR (2004), 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 (1993-2004). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from EIA (2004), as described in Annex 2.1: Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion, and were reduced by the amount allocated to international bunker fuels. Data on fuel consumption by all other off-road modes⁸ were obtained from EPA's NONROAD model (EPA 2004c). Finally, gasoline consumption for trucks used off-road was taken from FHWA (1996-2004).

Emissions of CH₄ and N₂O 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 3-30).

Table 3-31 and Table 3-32 provide complete emissions of CH₄ and N₂O emissions, respectively, for 1990 through 2003.

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 2004e), 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 3-33 through Table 3-35 provide complete emissions estimates for 1990 through 2003.

Table 3-6: Vehicle Miles Traveled for Gasoline Highway Vehicles (10⁹ Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles	Motorcycles
1990	1,392.9	555.9	33.3	9.6
1991	1,344.2	630.2	40.4	9.2
1992	1,356.9	685.4	36.5	9.6
1993	1,358.1	722.1	33.3	9.9
1994	1,389.0	740.3	33.4	10.2
1995	1,422.2	764.3	34.3	9.8
1996	1,456.0	789.8	34.7	9.9
1997	1,489.3	822.0	32.7	10.1
1998	1,537.5	839.1	35.3	10.3
1999	1,559.6	870.1	35.3	10.6
2000	1,592.0	890.9	34.5	10.5
2001	1,619.8	910.1	34.5	9.6
2002	1,649.7	932.0	35.4	9.6
2003	1,652.1	963.0	35.4	9.5

Source: Derived from FHWA (1996 through 2004).

Table 3-7: Vehicle Miles Traveled for Diesel Highway Vehicles (10⁹ Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	15.3	17.8	117.7
1991	13.9	18.5	114.0
1992	14.6	20.8	121.8
1993	16.5	22.8	131.6
1994	16.9	23.5	142.2
1995	15.9	24.8	149.2

⁸ "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.

1996	13.6	25.8	153.7
1997	12.9	27.8	164.4
1998	11.8	28.1	166.8
1999	9.1	29.7	173.7
2000	7.9	30.9	177.2
2001	8.0	31.7	179.9
2002	8.2	32.5	184.3
2003	8.2	33.5	185.2

Source: Derived from FHWA (1996 through 2004).

Table 3-8: Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10⁹ 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

Source: Derived from Browning (2003).

Table 3-9: Detailed Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10⁶ Miles)

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

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 3-10: 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 aggregated together.

Table 3-11: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,^a 1999

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	8.1%	9.3%	8.7%	8.1%	9.3%	8.7%	9.5%
1	6.1%	8.4%	7.0%	6.1%	8.4%	7.0%	9.3%
2	6.2%	7.9%	6.2%	6.2%	7.9%	6.2%	7.5%
3	5.9%	9.2%	6.0%	5.9%	9.2%	6.0%	6.8%
4	6.9%	9.7%	7.2%	6.9%	9.7%	7.2%	6.1%
5	6.1%	9.2%	6.6%	6.1%	9.2%	6.6%	5.7%
6	6.1%	7.9%	5.3%	6.1%	7.9%	5.3%	5.2%
7	5.6%	5.9%	4.0%	5.6%	5.9%	4.0%	4.3%
8	5.8%	5.6%	4.0%	5.8%	5.6%	4.0%	3.7%
9	5.8%	4.9%	5.0%	5.8%	4.9%	5.0%	3.5%
10	6.1%	4.9%	5.7%	6.1%	4.9%	5.7%	3.4%
11	5.9%	4.4%	5.3%	5.9%	4.4%	5.3%	3.9%
12	5.3%	4.0%	4.6%	5.3%	4.0%	4.6%	4.6%
13	4.8%	3.5%	4.9%	4.8%	3.5%	4.9%	4.2%
14	3.9%	1.9%	3.9%	3.9%	1.9%	3.9%	3.8%
15	3.1%	1.3%	2.7%	3.1%	1.3%	2.7%	3.4%
16	1.9%	0.7%	2.7%	1.9%	0.7%	2.7%	3.1%
17	1.2%	0.3%	1.5%	1.2%	0.3%	1.5%	2.7%
18	1.0%	0.2%	1.4%	1.0%	0.2%	1.4%	2.3%
19	0.9%	0.2%	1.3%	0.9%	0.2%	1.3%	2.0%
20	1.0%	0.1%	1.1%	1.0%	0.1%	1.1%	1.6%
21	0.8%	0.2%	1.2%	0.8%	0.2%	1.2%	1.3%
22	0.6%	0.1%	0.8%	0.6%	0.1%	0.8%	0.9%
23	0.4%	0.0%	0.6%	0.4%	0.0%	0.6%	0.6%

24	0.2%	0.0%	0.5%	0.2%	0.0%	0.5%	0.3%
25	0.3%	0.0%	0.4%	0.3%	0.0%	0.4%	0.0%
26	0.0%	0.0%	0.4%	0.0%	0.0%	0.4%	0.0%
27	0.0%	0.0%	0.7%	0.0%	0.0%	0.7%	0.0%
28	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.0%
29	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.0%
30	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2004b).

^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 3-12: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,^a 2000

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	8.8%	9.8%	8.7%	8.8%	9.8%	8.7%	11.8%
1	8.6%	9.4%	9.5%	8.6%	9.4%	9.5%	8.9%
2	6.4%	8.5%	7.6%	6.4%	8.5%	7.6%	8.7%
3	6.6%	7.9%	6.8%	6.6%	7.9%	6.8%	7.0%
4	6.2%	9.3%	6.5%	6.2%	9.3%	6.5%	6.2%
5	7.3%	9.7%	7.7%	7.3%	9.7%	7.7%	5.6%
6	6.4%	8.9%	6.9%	6.4%	8.9%	6.9%	5.2%
7	6.4%	7.5%	5.4%	6.4%	7.5%	5.4%	4.7%
8	5.7%	5.4%	4.0%	5.7%	5.4%	4.0%	3.8%
9	5.7%	4.9%	3.9%	5.7%	4.9%	3.9%	3.3%
10	5.4%	4.0%	4.7%	5.4%	4.0%	4.7%	3.1%
11	5.5%	3.9%	5.2%	5.5%	3.9%	5.2%	2.9%
12	4.9%	3.2%	4.6%	4.9%	3.2%	4.6%	3.3%
13	4.2%	2.8%	3.8%	4.2%	2.8%	3.8%	3.9%
14	3.5%	2.2%	3.8%	3.5%	2.2%	3.8%	3.5%
15	2.7%	1.1%	2.9%	2.7%	1.1%	2.9%	3.2%
16	1.9%	0.7%	1.9%	1.9%	0.7%	1.9%	2.9%
17	1.1%	0.3%	1.7%	1.1%	0.3%	1.7%	2.5%
18	0.7%	0.1%	0.9%	0.7%	0.1%	0.9%	2.2%
19	0.5%	0.1%	0.8%	0.5%	0.1%	0.8%	1.9%
20	0.4%	0.1%	0.7%	0.4%	0.1%	0.7%	1.6%
21	0.4%	0.0%	0.5%	0.4%	0.0%	0.5%	1.3%
22	0.3%	0.0%	0.5%	0.3%	0.0%	0.5%	1.0%
23	0.2%	0.0%	0.3%	0.2%	0.0%	0.3%	0.7%
24	0.1%	0.0%	0.2%	0.1%	0.0%	0.2%	0.5%
25	0.0%	0.0%	0.2%	0.0%	0.0%	0.2%	0.2%
26	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%
27	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.0%
28	0.0%	0.0%	0.2%	0.0%	0.0%	0.2%	0.0%
29	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
30	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2004b).

^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 3-13: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,^a 2001

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC ^b
0	8.6%	10.1%	7.3%	8.6%	10.1%	7.3%	13.1%
1	9.0%	9.7%	9.2%	9.0%	9.7%	9.2%	10.8%
2	8.9%	9.3%	10.1%	8.9%	9.3%	10.1%	8.2%
3	6.6%	8.4%	8.1%	6.6%	8.4%	8.1%	8.0%
4	6.8%	7.9%	7.2%	6.8%	7.9%	7.2%	6.3%
5	6.4%	9.1%	6.8%	6.4%	9.1%	6.8%	5.6%
6	7.5%	9.3%	7.9%	7.5%	9.3%	7.9%	5.0%
7	6.6%	8.4%	6.9%	6.6%	8.4%	6.9%	4.6%
8	6.4%	6.7%	5.3%	6.4%	6.7%	5.3%	4.1%

9	5.5%	4.7%	3.7%	5.5%	4.7%	3.7%	3.3%
10	5.2%	4.0%	3.6%	5.2%	4.0%	3.6%	2.8%
11	4.7%	3.1%	4.1%	4.7%	3.1%	4.1%	2.6%
12	4.5%	2.8%	4.3%	4.5%	2.8%	4.3%	2.5%
13	3.8%	2.2%	3.7%	3.8%	2.2%	3.7%	2.8%
14	3.0%	1.7%	2.9%	3.0%	1.7%	2.9%	3.2%
15	2.4%	1.3%	2.7%	2.4%	1.3%	2.7%	2.9%
16	1.6%	0.6%	2.0%	1.6%	0.6%	2.0%	2.6%
17	1.1%	0.3%	1.2%	1.1%	0.3%	1.2%	2.3%
18	0.5%	0.1%	1.0%	0.5%	0.1%	1.0%	2.0%
19	0.3%	0.1%	0.5%	0.3%	0.1%	0.5%	1.7%
20	0.2%	0.0%	0.4%	0.2%	0.0%	0.4%	1.5%
21	0.1%	0.0%	0.3%	0.1%	0.0%	0.3%	1.2%
22	0.1%	0.0%	0.2%	0.1%	0.0%	0.2%	1.0%
23	0.1%	0.0%	0.2%	0.1%	0.0%	0.2%	0.8%
24	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.6%
25	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.4%
26	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
27	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
28	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
29	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
30	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2004b).

^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 aggregated.

Table 3-14: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,^a 2002

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	8.4%	9.9%	6.7%	8.4%	9.9%	6.7%	11.8%
1	8.7%	9.9%	7.7%	8.7%	9.9%	7.7%	12.2%
2	9.1%	9.6%	9.7%	9.1%	9.6%	9.7%	10.1%
3	9.0%	9.2%	10.5%	9.0%	9.2%	10.5%	7.5%
4	6.7%	8.3%	8.5%	6.7%	8.3%	8.5%	7.3%
5	6.9%	7.7%	7.4%	6.9%	7.7%	7.4%	5.7%
6	6.5%	8.7%	6.9%	6.5%	8.7%	6.9%	5.0%
7	7.6%	8.7%	7.8%	7.6%	8.7%	7.8%	4.4%
8	6.4%	7.5%	6.7%	6.4%	7.5%	6.7%	4.0%
9	6.0%	5.8%	4.9%	6.0%	5.8%	4.9%	3.6%
10	4.9%	3.8%	3.4%	4.9%	3.8%	3.4%	2.9%
11	4.4%	3.1%	3.1%	4.4%	3.1%	3.1%	2.4%
12	3.8%	2.3%	3.4%	3.8%	2.3%	3.4%	2.3%
13	3.4%	1.9%	3.4%	3.4%	1.9%	3.4%	2.1%
14	2.7%	1.4%	2.7%	2.7%	1.4%	2.7%	2.3%
15	2.0%	1.0%	2.0%	2.0%	1.0%	2.0%	2.7%
16	1.4%	0.7%	1.8%	1.4%	0.7%	1.8%	2.4%
17	0.9%	0.3%	1.2%	0.9%	0.3%	1.2%	2.2%
18	0.5%	0.1%	0.7%	0.5%	0.1%	0.7%	1.9%
19	0.2%	0.1%	0.6%	0.2%	0.1%	0.6%	1.6%
20	0.1%	0.0%	0.3%	0.1%	0.0%	0.3%	1.4%
21	0.1%	0.0%	0.2%	0.1%	0.0%	0.2%	1.2%
22	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	1.0%
23	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.8%
24	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.6%
25	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
26	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
27	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
28	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
29	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
30	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Total	100%	100%	100%	100%	100%	100%	100%
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Source: EPA (2004b).

^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 3-15: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,^a 2003

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	8.2%	9.5%	6.7%	8.2%	9.5%	6.7%	11.0%
1	8.4%	9.8%	6.9%	8.4%	9.8%	6.9%	11.1%
2	8.7%	9.8%	7.9%	8.7%	9.8%	7.9%	11.4%
3	9.2%	9.5%	10.0%	9.2%	9.5%	10.0%	9.3%
4	9.0%	9.1%	10.9%	9.0%	9.1%	10.9%	6.9%
5	6.7%	8.2%	8.7%	6.7%	8.2%	8.7%	6.6%
6	6.9%	7.4%	7.4%	6.9%	7.4%	7.4%	5.2%
7	6.5%	8.1%	6.8%	6.5%	8.1%	6.8%	4.5%
8	7.3%	7.8%	7.5%	7.3%	7.8%	7.5%	3.9%
9	6.0%	6.4%	6.1%	6.0%	6.4%	6.1%	3.5%
10	5.3%	4.7%	4.4%	5.3%	4.7%	4.4%	3.1%
11	4.2%	2.9%	2.9%	4.2%	2.9%	2.9%	2.5%
12	3.5%	2.2%	2.5%	3.5%	2.2%	2.5%	2.1%
13	2.9%	1.5%	2.7%	2.9%	1.5%	2.7%	1.9%
14	2.4%	1.2%	2.5%	2.4%	1.2%	2.5%	1.8%
15	1.8%	0.8%	1.9%	1.8%	0.8%	1.9%	2.0%
16	1.2%	0.5%	1.3%	1.2%	0.5%	1.3%	2.3%
17	0.8%	0.3%	1.1%	0.8%	0.3%	1.1%	2.0%
18	0.5%	0.1%	0.7%	0.5%	0.1%	0.7%	1.8%
19	0.2%	0.1%	0.4%	0.2%	0.1%	0.4%	1.5%
20	0.1%	0.0%	0.3%	0.1%	0.0%	0.3%	1.3%
21	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	1.1%
22	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.9%
23	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.8%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%
25	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
26	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
27	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
28	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
29	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
30	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2004b).

^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 3-16: 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 aggregated.

Table 3-17: 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 3-10 by data in Table 3-16.

Table 3-18: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 1999

Vehicle Age	LDGV	LDGT	HdGV	LDDV	LDDT	HDDV	MC
0	11.64%	13.29%	13.85%	11.64%	14.64%	15.86%	16.17%
1	8.27%	11.29%	10.44%	8.27%	12.11%	11.67%	14.92%
2	8.07%	9.87%	8.35%	8.07%	10.33%	9.44%	11.21%
3	7.21%	10.82%	7.83%	7.21%	11.06%	8.34%	9.36%

4	8.06%	10.69%	8.80%	8.06%	10.68%	9.13%	7.74%
5	6.76%	9.45%	7.50%	6.76%	9.25%	7.59%	6.57%
6	6.47%	7.59%	5.64%	6.47%	7.29%	5.57%	5.41%
7	5.66%	5.31%	3.97%	5.66%	5.01%	3.83%	4.03%
8	5.49%	4.66%	3.79%	5.49%	4.33%	3.56%	3.04%
9	5.25%	3.77%	4.41%	5.25%	3.45%	4.05%	2.52%
10	5.26%	3.55%	4.74%	5.26%	3.21%	4.25%	2.01%
11	4.80%	2.93%	4.11%	4.80%	2.62%	3.59%	1.89%
12	4.14%	2.48%	3.33%	4.14%	2.21%	2.84%	2.25%
13	3.53%	1.98%	3.31%	3.53%	1.75%	2.76%	2.06%
14	2.75%	1.01%	2.47%	2.75%	0.89%	2.03%	1.87%
15	2.05%	0.63%	1.62%	2.05%	0.56%	1.29%	1.68%
16	1.19%	0.32%	1.51%	1.19%	0.28%	1.17%	1.50%
17	0.75%	0.13%	0.81%	0.75%	0.11%	0.61%	1.32%
18	0.60%	0.09%	0.68%	0.60%	0.08%	0.50%	1.14%
19	0.47%	0.05%	0.61%	0.47%	0.05%	0.44%	0.97%
20	0.53%	0.04%	0.48%	0.53%	0.04%	0.34%	0.80%
21	0.39%	0.04%	0.50%	0.39%	0.04%	0.34%	0.63%
22	0.28%	0.01%	0.29%	0.28%	0.01%	0.19%	0.46%
23	0.17%	0.01%	0.23%	0.17%	0.01%	0.15%	0.30%
24	0.10%	0.00%	0.17%	0.10%	0.00%	0.11%	0.14%
25	0.12%	0.00%	0.13%	0.12%	0.00%	0.08%	0.00%
26	0.00%	0.00%	0.12%	0.00%	0.00%	0.08%	0.00%
27	0.00%	0.00%	0.22%	0.00%	0.00%	0.14%	0.00%
28	0.00%	0.00%	0.05%	0.00%	0.00%	0.03%	0.00%
29	0.00%	0.00%	0.02%	0.00%	0.00%	0.01%	0.00%
30	0.00%	0.00%	0.02%	0.00%	0.00%	0.01%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table 3-11 by data in Table 3-16.

Table 3-19: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2000

Vehicle Age	LDGV	LDGT	HDBGV	LDDV	LDDT	HDDV	MC
0	12.11%	13.68%	13.07%	12.11%	15.04%	14.76%	19.41%
1	11.32%	12.37%	13.37%	11.32%	13.25%	14.73%	13.64%
2	8.03%	10.50%	9.72%	8.03%	10.96%	10.83%	12.53%
3	7.84%	9.17%	8.36%	7.84%	9.35%	8.76%	9.26%
4	7.00%	10.04%	7.56%	7.00%	10.01%	7.74%	7.61%
5	7.83%	9.84%	8.37%	7.83%	9.61%	8.35%	6.18%
6	6.57%	8.47%	7.00%	6.57%	8.12%	6.82%	5.19%
7	6.25%	6.60%	5.14%	6.25%	6.21%	4.89%	4.19%
8	5.30%	4.44%	3.53%	5.30%	4.12%	3.27%	3.04%
9	4.95%	3.73%	3.26%	4.95%	3.41%	2.95%	2.23%
10	4.52%	2.86%	3.67%	4.52%	2.58%	3.24%	1.78%
11	4.32%	2.55%	3.79%	4.32%	2.27%	3.26%	1.37%
12	3.72%	1.97%	3.14%	3.72%	1.74%	2.64%	1.57%
13	3.02%	1.55%	2.43%	3.02%	1.37%	1.99%	1.85%
14	2.40%	1.14%	2.27%	2.40%	1.01%	1.83%	1.67%
15	1.74%	0.53%	1.64%	1.74%	0.47%	1.28%	1.52%
16	1.19%	0.30%	1.00%	1.19%	0.27%	0.76%	1.35%
17	0.63%	0.14%	0.87%	0.63%	0.12%	0.65%	1.19%
18	0.36%	0.05%	0.43%	0.36%	0.04%	0.32%	1.03%
19	0.26%	0.03%	0.34%	0.26%	0.03%	0.24%	0.89%
20	0.18%	0.02%	0.28%	0.18%	0.01%	0.20%	0.75%
21	0.18%	0.01%	0.21%	0.18%	0.01%	0.14%	0.61%
22	0.12%	0.01%	0.20%	0.12%	0.01%	0.13%	0.48%
23	0.07%	0.00%	0.10%	0.07%	0.00%	0.07%	0.35%
24	0.04%	0.00%	0.07%	0.04%	0.00%	0.05%	0.22%
25	0.02%	0.00%	0.05%	0.02%	0.00%	0.03%	0.10%
26	0.02%	0.00%	0.04%	0.02%	0.00%	0.02%	0.00%
27	0.00%	0.00%	0.03%	0.00%	0.00%	0.02%	0.00%
28	0.00%	0.00%	0.05%	0.00%	0.00%	0.03%	0.00%

29	0.00%	0.00%	0.01%	0.00%	0.00%	0.01%	0.00%
30	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table 3-12 by data in Table 3-16.

Table 3-20: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2001

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	11.63%	13.94%	10.78%	11.63%	15.30%	12.10%	20.77%
1	11.61%	12.63%	12.70%	11.61%	13.50%	13.91%	16.07%
2	10.85%	11.41%	12.53%	10.85%	11.90%	13.88%	11.24%
3	7.70%	9.67%	9.80%	7.70%	9.85%	10.21%	10.16%
4	7.52%	8.43%	8.12%	7.52%	8.40%	8.26%	7.39%
5	6.72%	9.16%	7.24%	6.72%	8.93%	7.19%	5.96%
6	7.51%	8.74%	7.86%	7.51%	8.36%	7.61%	4.79%
7	6.26%	7.30%	6.43%	6.26%	6.86%	6.07%	3.94%
8	5.77%	5.47%	4.60%	5.77%	5.06%	4.24%	3.10%
9	4.71%	3.52%	3.05%	4.71%	3.21%	2.75%	2.19%
10	4.21%	2.81%	2.72%	4.21%	2.53%	2.39%	1.54%
11	3.66%	2.04%	2.95%	3.66%	1.82%	2.52%	1.19%
12	3.30%	1.70%	2.91%	3.30%	1.50%	2.43%	1.12%
13	2.68%	1.22%	2.30%	2.68%	1.07%	1.88%	1.26%
14	2.02%	0.89%	1.67%	2.02%	0.78%	1.35%	1.47%
15	1.50%	0.60%	1.51%	1.50%	0.52%	1.17%	1.33%
16	0.99%	0.25%	1.01%	0.99%	0.22%	0.77%	1.19%
17	0.62%	0.13%	0.58%	0.62%	0.11%	0.43%	1.05%
18	0.30%	0.05%	0.47%	0.30%	0.05%	0.34%	0.91%
19	0.16%	0.02%	0.22%	0.16%	0.01%	0.15%	0.79%
20	0.10%	0.01%	0.16%	0.10%	0.01%	0.11%	0.67%
21	0.06%	0.00%	0.12%	0.06%	0.00%	0.08%	0.56%
22	0.05%	0.00%	0.08%	0.05%	0.00%	0.05%	0.45%
23	0.03%	0.00%	0.07%	0.03%	0.00%	0.05%	0.35%
24	0.02%	0.00%	0.03%	0.02%	0.00%	0.02%	0.25%
25	0.01%	0.00%	0.02%	0.01%	0.00%	0.01%	0.16%
26	0.00%	0.00%	0.02%	0.00%	0.00%	0.01%	0.07%
27	0.00%	0.00%	0.01%	0.00%	0.00%	0.01%	0.00%
28	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
29	0.00%	0.00%	0.01%	0.00%	0.00%	0.01%	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 3-13 by data in Table 3-16.

Table 3-21: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2002

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	11.21%	13.70%	9.77%	11.21%	15.02%	10.96%	18.38%
1	11.07%	12.86%	10.47%	11.07%	13.73%	11.45%	17.68%
2	11.06%	11.64%	11.89%	11.06%	12.12%	13.17%	13.61%
3	10.34%	10.50%	12.62%	10.34%	10.68%	13.14%	9.37%
4	7.34%	8.89%	9.51%	7.34%	8.84%	9.67%	8.33%
5	7.16%	7.69%	7.77%	7.16%	7.49%	7.71%	5.95%
6	6.40%	8.13%	6.80%	6.40%	7.77%	6.58%	4.75%
7	7.11%	7.53%	7.22%	7.11%	7.07%	6.82%	3.74%
8	5.74%	6.05%	5.75%	5.74%	5.59%	5.29%	3.00%
9	5.10%	4.34%	3.98%	5.10%	3.95%	3.58%	2.29%
10	3.98%	2.65%	2.55%	3.98%	2.39%	2.24%	1.56%
11	3.39%	2.00%	2.19%	3.39%	1.78%	1.87%	1.07%
12	2.78%	1.36%	2.27%	2.78%	1.20%	1.89%	1.00%
13	2.36%	1.05%	2.13%	2.36%	0.92%	1.74%	0.93%
14	1.78%	0.70%	1.59%	1.78%	0.61%	1.27%	1.03%
15	1.25%	0.46%	1.11%	1.25%	0.41%	0.86%	1.20%
16	0.85%	0.28%	0.93%	0.85%	0.25%	0.71%	1.08%

17	0.52%	0.11%	0.59%	0.52%	0.10%	0.43%	0.95%
18	0.29%	0.05%	0.31%	0.29%	0.04%	0.23%	0.83%
19	0.13%	0.02%	0.24%	0.13%	0.02%	0.17%	0.71%
20	0.06%	0.00%	0.10%	0.06%	0.00%	0.07%	0.61%
21	0.03%	0.00%	0.07%	0.03%	0.00%	0.05%	0.52%
22	0.02%	0.00%	0.05%	0.02%	0.00%	0.03%	0.43%
23	0.01%	0.00%	0.03%	0.01%	0.00%	0.02%	0.34%
24	0.01%	0.00%	0.02%	0.01%	0.00%	0.01%	0.26%
25	0.00%	0.00%	0.01%	0.00%	0.00%	0.01%	0.19%
26	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.12%
27	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%
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 3-14 by data in Table 3-16.

Table 3-22: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2003

Vehicle Age	LDGV	LDGT	HdGV	LDDV	LDDT	HDDV	MC
0	10.96%	13.06%	9.73%	10.96%	14.32%	10.93%	16.86%
1	10.63%	12.70%	9.44%	10.63%	13.57%	10.35%	15.93%
2	10.50%	11.91%	9.75%	10.50%	12.41%	10.81%	15.25%
3	10.49%	10.77%	11.91%	10.49%	10.96%	12.43%	11.56%
4	9.80%	9.70%	12.19%	9.80%	9.66%	12.41%	7.83%
5	6.96%	8.14%	9.05%	6.96%	7.94%	8.99%	6.83%
6	6.79%	6.86%	7.26%	6.79%	6.56%	7.04%	4.83%
7	6.03%	7.04%	6.21%	6.03%	6.61%	5.87%	3.78%
8	6.50%	6.27%	6.42%	6.50%	5.80%	5.92%	2.90%
9	5.05%	4.82%	4.95%	5.05%	4.40%	4.45%	2.26%
10	4.29%	3.28%	3.31%	4.29%	2.96%	2.91%	1.67%
11	3.19%	1.89%	2.04%	3.19%	1.69%	1.75%	1.10%
12	2.56%	1.34%	1.67%	2.56%	1.18%	1.40%	0.91%
13	1.98%	0.84%	1.65%	1.98%	0.74%	1.35%	0.84%
14	1.57%	0.60%	1.46%	1.57%	0.53%	1.18%	0.77%
15	1.10%	0.37%	1.05%	1.10%	0.32%	0.82%	0.86%
16	0.71%	0.22%	0.68%	0.71%	0.19%	0.52%	0.99%
17	0.44%	0.12%	0.54%	0.44%	0.11%	0.40%	0.88%
18	0.24%	0.04%	0.32%	0.24%	0.04%	0.23%	0.77%
19	0.12%	0.02%	0.16%	0.12%	0.02%	0.11%	0.66%
20	0.05%	0.01%	0.11%	0.05%	0.00%	0.08%	0.57%
21	0.02%	0.00%	0.04%	0.02%	0.00%	0.03%	0.48%
22	0.01%	0.00%	0.03%	0.01%	0.00%	0.02%	0.40%
23	0.00%	0.00%	0.02%	0.00%	0.00%	0.01%	0.33%
24	0.00%	0.00%	0.01%	0.00%	0.00%	0.01%	0.26%
25	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.20%
26	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.14%
27	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.09%
28	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%
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 3-15 by data in Table 3-16.

Table 3-23: Fuel Consumption for Non-Highway Vehicles by Fuel Type (thousand gallons)

Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Aircraft														
Gasoline ^a	374,216	347,126	341,582	319,449	317,307	329,319	310,797	330,285	295,345	325,913	301,893	290,677	280,635	272,149
Jet Fuel	18,318,381	17,513,765	17,295,491	17,428,433	18,300,089	17,845,394	18,744,445	18,603,875	18,883,887	19,428,608	20,129,531	19,108,184	18,220,423	17,841,446
Ships and Boats														
Diesel	1,697,600	1,693,361	1,706,144	1,546,311	1,630,093	1,518,608	1,839,335	1,801,798	1,597,011	1,863,606	1,854,297	1,998,357	2,014,725	1,825,176
Gasoline	1,090,912	1,113,589	1,136,267	1,307,216	1,209,134	1,259,324	1,309,513	1,312,734	1,315,898	1,317,307	1,315,638	1,316,380	1,311,943	1,307,216
Residual	2,060,708	1,553,714	2,727,447	2,511,169	2,451,117	2,646,106	2,168,468	976,197	584,334	1,238,111	3,027,560	1,130,728	2,441,344	2,587,613
Construction Equipment														
Diesel	3,508,174	3,644,435	3,780,696	5,284,322	4,053,217	4,189,478	4,325,738	4,461,999	4,598,260	4,732,358	4,866,456	5,005,744	5,145,033	5,284,322
Gasoline	392,463	361,463	347,163	309,512	347,115	354,309	356,023	369,834	303,231	245,919	259,512	572,884	598,103	634,463
Agricultural Equipment														
Diesel	2,291,529	2,380,534	2,469,539	3,427,404	2,647,549	2,736,554	2,825,559	2,914,564	3,003,570	3,092,575	3,181,580	3,263,521	3,345,462	3,427,404
Gasoline	812,800	776,200	805,500	845,320	911,996	926,732	918,085	984,450	906,941	702,700	652,256	801,552	831,828	853,104
Locomotives														
Diesel	3,460,643	3,253,801	3,350,575	3,445,263	3,716,218	3,863,531	3,933,763	3,946,644	3,974,540	4,121,606	4,105,893	4,119,035	4,159,977	4,257,793
Other^b														
Diesel	670,870	692,490	714,110	963,216	757,350	778,969	800,589	822,209	843,829	858,602	886,719	912,218	937,717	963,216
Gasoline	2,723,687	2,756,578	2,784,868	2,950,262	2,710,192	2,772,469	2,849,748	2,775,371	2,829,760	2,748,437	2,825,593	3,576,179	3,677,763	3,812,235

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

^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 3-24: 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%

Sources: EPA (1998), EPA (2004a), and EPA (2004d).

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

- Not applicable.

Table 3-25: 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%

Sources: EPA (1998), EPA (2004a), and EPA (2004d)

^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 3-26: 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%

Sources: EPA (1998), EPA (2004a), and EPA (2004d).

^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 3-27: Control Technology Assignments for Diesel Highway Vehicles and Motorcycles

Vehicle Type/Control Technology	Model Years
Diesel Passenger Cars and Light-Duty Trucks	
Uncontrolled	1966-1982
Moderate control	1983-1995
Advanced control	1996-2002
Heavy-Duty Diesel Vehicles	
Uncontrolled	1966-1982
Moderate control	1983-1995
Advanced control	1996-2002
Motorcycles	
Uncontrolled	1966-1995
Non-catalyst controls	1996-2003

Source: EPA (1998)

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

Table 3-28: Emission Factors for CH₄ and N₂O for Highway Vehicles

Vehicle Type/Control Technology	N ₂ O (g/mi)	N ₂ O (g/km)	CH ₄ (g/mi)	CH ₄ (g/km)
Gasoline Passenger Cars				
Low Emission Vehicles	0.0222	0.0138	0.0169	0.0105
EPA Tier 1 ^a	0.0429	0.0267	0.0271	0.0168
EPA Tier 0 ^a	0.0647	0.0402	0.0704	0.0437
Oxidation Catalyst	0.0504	0.0313	0.1355	0.0842
Non-Catalyst Control	0.0197	0.0122	0.1696	0.1054
Uncontrolled	0.0197	0.0122	0.1780	0.1106
Gasoline Light-Duty Trucks				
Low Emission Vehicles	0.0146	0.0091	0.0216	0.0134
EPA Tier 1 ^a	0.0871	0.0541	0.0452	0.0281
EPA Tier 0 ^a	0.1056	0.0656	0.0776	0.0482
Oxidation Catalyst	0.0639	0.0397	0.1516	0.0942
Non-Catalyst Control	0.0218	0.0135	0.1908	0.1186
Uncontrolled	0.0220	0.0137	0.2024	0.1258
Gasoline Heavy-Duty Vehicles				
Low Emission Vehicles	0.0290	0.0180	0.0434	0.0270
EPA Tier 1 ^a	0.1750	0.1087	0.0655	0.0407
EPA Tier 0 ^a	0.2135	0.1326	0.2630	0.1634

Oxidation Catalyst	0.1317	0.0818	0.2356	0.1464
Non-Catalyst Control	0.0473	0.0294	0.4181	0.2598
Uncontrolled	0.0497	0.0309	0.4604	0.2861
Diesel Passenger Cars				
Advanced	0.0010	0.0006	0.0005	0.0003
Moderate	0.0010	0.0006	0.0005	0.0003
Uncontrolled	0.0012	0.0008	0.0006	0.0004
Diesel Light-Duty Trucks				
Advanced	0.0015	0.0009	0.0005	0.0003
Moderate	0.0014	0.0009	0.0005	0.0003
Uncontrolled	0.0017	0.0010	0.0006	0.0004
Diesel Heavy-Duty Vehicles				
Advanced	0.0048	0.0030	0.0051	0.0032
Moderate	0.0048	0.0030	0.0051	0.0032
Uncontrolled	0.0048	0.0030	0.0051	0.0032
Motorcycles				
Non-Catalyst Control	0.0069	0.0043	0.0672	0.0418
Uncontrolled	0.0087	0.0054	0.0899	0.0559

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 3-29: Emission Factors for CH₄ and N₂O for Alternative Fuel Vehicles

Vehicle Type/Control Technology	N ₂ O (g/mi)	N ₂ O (g/km)	CH ₄ (g/mi)	CH ₄ (g/km)
Light-duty Vehicles				
Methanol	0.063	0.039	0.014	0.009
CNG	0.113	0.070	0.914	0.568
LPG	0.008	0.005	0.038	0.024
Ethanol	0.076	0.047	0.043	0.027
Heavy-duty Vehicles				
Methanol	0.217	0.135	0.646	0.401
CNG	0.297	0.185	9.629	5.983
LNG	0.440	0.274	6.857	4.261
LPG	0.150	0.093	0.108	0.067
Ethanol	0.307	0.191	1.975	1.227
Buses				
Methanol	0.217	0.135	0.646	0.401
CNG	0.162	0.101	12.416	7.715
Ethanol	0.364	0.226	2.079	1.292

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

Table 3-30: Emission Factors for CH₄ and N₂O Emissions from Non-Highway Mobile Combustion (g gas/kg fuel)

Vehicle Type/Fuel Type	N ₂ O	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 3-31: CH₄ Emissions from Mobile Combustion (Tg CO₂ Eq.)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Gasoline Highway	4.3	4.2	4.2	4.1	4.0	3.9	3.7	3.5	3.3	3.0	2.7	2.4	2.2	2.0
Passenger Cars	2.6	2.4	2.3	2.3	2.2	2.1	2.0	1.9	1.8	1.7	1.5	1.4	1.2	1.1
Light-Duty Trucks	1.4	1.5	1.5	1.5	1.5	1.4	1.4	1.3	1.3	1.1	1.0	0.9	0.8	0.8
Heavy-Duty Vehicles	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	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
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
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
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
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
Aircraft	+	+	+	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
Total	4.8	4.7	4.7	4.6	4.5	4.4	4.2	4.0	3.9	3.6	3.4	3.1	2.9	2.7

+ Less than 0.05 Tg CO₂ 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 3-32: N₂O Emissions from Mobile Combustion (Tg CO₂ Eq.)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Gasoline Highway	40.3	42.8	45.5	47.5	49.0	50.1	50.8	51.5	51.7	50.8	49.1	45.0	41.6	38.0
Passenger Cars	25.5	25.1	25.8	26.1	26.7	26.9	26.9	26.7	26.7	25.9	24.7	23.1	21.6	19.8
Light-Duty Trucks	14.1	16.7	18.8	20.4	21.3	22.2	22.9	23.7	23.7	23.6	23.0	20.6	18.6	16.7
Heavy-Duty Vehicles	0.7	1.0	0.9	0.9	0.9	1.0	1.1	1.1	1.3	1.3	1.3	1.4	1.4	1.4
Motorcycles	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Diesel Highway	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
Passenger Cars	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.2	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
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
Non-Highway	3.2	3.1	3.2	3.4	3.3	3.3	3.4	3.3	3.3	3.4	3.7	3.5	3.6	3.6
Ships and Boats	0.4	0.3	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.5	0.3	0.5	0.5
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
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
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
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
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
Total	43.7	46.0	48.9	51.1	52.6	53.7	54.6	55.2	55.3	54.6	53.2	49.0	45.6	42.1

+ Less than 0.05 Tg CO₂ 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 3-33: NO_x Emissions from Mobile Combustion, 1990-2003 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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	3,527
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	1,924
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	1,220

Heavy-Duty Vehicles	515	505	496	487	478	469	459	475	467	485	411	390	369	370
Motorcycles	20	19	17	16	15	14	13	13	13	13	13	14	13	13
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	3,169
Passenger Cars	39	35	31	27	23	19	15	13	11	10	7	6	6	6
Light-Duty Trucks	20	19	17	16	14	12	11	10	9	8	6	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	3,158
Alternative Fuel Highway^a	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	3,722
Ships and Boats	953	962	971	980	990	999	1,008	963	919	818	966	971	954	958
Locomotives	857	873	888	904	920	935	951	962	973	910	908	907	891	895
Agricultural Equipment	63	64	65	65	66	67	67	75	83	84	80	73	72	72
Construction Equipment	437	445	453	461	470	478	486	487	487	497	484	480	472	474
Aircraft ^b	641	652	663	675	686	697	708	708	706	765	697	690	678	681
Other ^c	480	496	511	526	541	556	572	597	604	632	645	650	639	642
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	10,418

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 3-34: CO Emissions from Mobile Combustion, 1990-2003 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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	52,544
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	29,275
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	20,914
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	2,234
Motorcycles	240	223	206	189	172	155	138	150	163	164	154	131	129	122
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	805
Passenger Cars	35	31	28	25	21	18	15	13	10	10	7	6	6	5
Light-Duty Trucks	22	21	20	18	17	16	14	13	12	9	6	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	795
Alternative Fuel Highway^a	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	22,177
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
Locomotives	85	86	88	90	91	93	94	89	83	98	90	90	89	89
Agricultural Equipment	217	218	220	221	222	224	225	250	274	285	245	233	231	231
Construction Equipment	582	591	600	610	619	628	638	636	633	630	626	621	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	1,031
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	18,276
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	75,526

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 3-35: NMVOCs Emissions from Mobile Combustion, 1990-2003 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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	3,832
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	2,140
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	1,488
Heavy-Duty Vehicles	575	536	498	459	420	382	343	336	335	351	232	206	189	184
Motorcycles	42	38	35	31	28	24	21	22	25	28	23	22	20	20
Diesel Highway	406	386	365	345	324	304	283	263	249	230	216	207	190	185
Passenger Cars	16	15	13	12	10	8	7	6	5	5	3	3	3	3
Light-Duty Trucks	14	13	12	11	10	9	9	8	7	6	4	4	3	3
Heavy-Duty Vehicles	377	358	340	322	304	286	268	249	237	219	209	201	184	179
Alternative Fuel Highway^a	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	2,333
Ships and Boats	608	634	660	687	713	739	765	766	763	769	744	730	748	716
Locomotives	33	34	35	35	36	36	37	35	33	38	35	35	36	35
Agricultural Equipment	28	28	28	28	28	28	28	32	35	38	24	19	20	19
Construction Equipment	85	85	85	86	86	86	86	83	81	81	76	72	74	71
Aircraft ^b	149	150	150	151	152	152	153	142	137	141	130	125	128	123
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	1,370
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	6,351

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 N₂O and CH₄ emission factors used depend on the emission standards in place and the corresponding level of control technology for each vehicle type. Table 3-24 through Table 3-27 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 not have significant control technologies in place.

Gasoline Emission Controls

Below are the control technologies and emissions standards applicable to gasoline vehicles.

Non-catalyst

These emission controls were common in gasoline passenger cars and light-duty gasoline trucks during model years (1973-1974) but phased out thereafter, in heavy-duty gasoline vehicles beginning in the mid-1980s, and in motorcycles beginning in 1996. This technology reduces hydrocarbon (HC) and carbon monoxide (CO) emissions through adjustments to ignition timing and air-fuel ratio, air injection into the exhaust manifold, and exhaust gas recirculation (EGR) valves, which also helps meet vehicle NO_x standards.

Oxidation Catalyst

This control technology designation represents the introduction of the catalytic converter, and was the most common technology in gasoline passenger cars and light-duty gasoline trucks made from 1975 to 1980 (cars) and

1975 to 1985 (trucks). This technology was also used in some heavy-duty gasoline vehicles between 1982 and 1997. The two-way catalytic converter oxidizes HC and CO, significantly reducing emissions over 80 percent beyond non-catalyst-system capacity. One reason unleaded gasoline was introduced in 1975 was due to the fact that oxidation catalysts cannot function properly with leaded gasoline.

EPA Tier 0

This emission standard from the Clean Air Act was met through the implementation of early "three-way" catalysts, therefore this technology was used in gasoline passenger cars and light-duty gasoline trucks sold beginning in the early 1980s, and remained common until 1994. This more sophisticated emission control system improves the efficiency of the catalyst by converting CO and HC to CO₂ and H₂O, reducing NO_x to nitrogen and oxygen, and using an on-board diagnostic computer and oxygen sensor. In addition, this type of catalyst includes a fuel metering system (carburetor or fuel injection) with electronic "trim" (also known as a "closed-loop system"). New cars with three-way catalysts met the Clean Air Act's amended standards (enacted in 1977) of reducing HC to 0.41 g/mile by 1980, CO to 3.4 g/mile by 1981 and NO_x to 1.0 g/mile by 1981.

EPA Tier 1

This emission standard created through the 1990 amendments to the Clean Air Act limited passenger car NO_x emissions to 0.4 g/mi, and HC emissions to 0.25 g/mi. These bounds respectively amounted to a 60 and 40 percent reduction from the EPA Tier 0 standard set in 1981. For light-duty trucks, this standard set emissions at 0.4 to 1.1 g/mi for NO_x, and 0.25 to 0.39 g/mi for HCs, depending on the weight of the truck. Emission reductions were met through the use of more advanced emission control systems, and applied to light-duty gasoline vehicles beginning in 1994. These advanced emission control systems included advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

Low Emission Vehicles (LEV)

This emission standard requires a much higher emission control level than the Tier 1 standard. Applied to light-duty gasoline passenger cars and trucks beginning in small numbers in the mid-1990s, LEV includes multi-port fuel injection with adaptive learning, an advanced computer diagnostics systems and advanced and close coupled catalysts with secondary air injection. LEVs as defined here include transitional low-emission vehicles (TLEVs), low emission vehicles, ultra-low emission vehicles (ULEVs) and super ultra-low emission vehicles (SULEVs). In this analysis, all categories of LEVs are treated the same due to the fact that there are very limited CH₄ or N₂O emission factor data for LEVs to distinguish among the different types of vehicles. Zero emission vehicles (ZEVs) are incorporated into the alternative fuel and advanced technology vehicle assessments.

Diesel Emission Controls

Below are the two levels of emissions control for diesel vehicles.

Moderate control

Improved injection timing technology and combustion system design for light- and heavy-duty diesel vehicles (generally in place in model years 1983 to 1995) are considered moderate control technologies. These controls were implemented to meet emission standards for diesel trucks and buses adopted by the EPA in 1985 to be met in 1991 and 1994.

Advanced control

EGR and modern electronic control of the fuel injection system are designated as advanced control technologies. These technologies provide diesel vehicles with the level of emission control necessary to comply with standards in place from 1996 through 2003.

Supplemental Information on GHG Emissions from Transportation and Other Mobile Sources

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. In addition to presenting methodologies used to estimate N₂O and CH₄ from mobile sources, this Annex also includes supplemental information on the methodology used to estimate CO₂ from transportation sources, presents estimates of CO₂ from other mobile sources (e.g., agricultural equipment, construction equipment, recreational vehicles), and provides information on the total contribution of transportation and mobile sources to greenhouse gas emissions in the United States. In the main body of the Inventory report, emission estimates are organized by greenhouse gas, with figures for CO₂, N₂O, CH₄, and HFC emissions generally presented separately. This section of the Annex reports total emissions from all of these gases in CO₂ equivalents in order to show the total contribution of individual transportation and other mobile sources to greenhouse gas emissions to national greenhouse gas estimates.

Methodology for Apportioning CO₂ Emissions to Transportation Modes

CO₂ emissions estimates for transportation sources, as presented in Table 3-7 of Chapter 3, were estimated using a “top down” methodology, based on estimates of total transportation sector fuel consumption by fuel type (i.e., motor gasoline, diesel, jet fuel, aviation gasoline, residual fuel oil, natural gas, LPG, and electricity) from the Energy Information Administration (EIA, 2004). Transportation-related CO₂ emissions by fuel type are calculated using the methodology described in Annex 2.1. The resulting CO₂ emissions estimates are then apportioned to travel modes and vehicle categories based on estimates of fuel consumption derived from various sources.

For highway vehicles, annual estimates of motor gasoline and diesel fuel consumption by vehicle category are taken from FHWA’s *Highway Statistics*’ annual editions, Table VM-1 (FHWA 1996 through 2004), and for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are 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 are then scaled for each year so that the sum of gasoline and diesel fuel consumption across all vehicle categories matches with the fuel consumption estimates in *Highway Statistics*’ Table MF-21 (FHWA 1996 through 2003). Gasoline fuel consumption from recreational boats is taken from EPA’s NONROAD Model (EPA 2004c). Diesel fuel consumption from locomotives comes from the Association of American Railroads (AAR 2004), the Upper Great Plains Transportation Institute (Benson, 2002 through 2004), and DOE’s *Transportation Energy Data Book* (DOE 1993 through 2004). Diesel and residual fuel consumption from ships and boats are taken from EIA’s *Fuel Oil and Kerosene Sales* (1991 through 2004). Natural gas and LPG fuel consumption by vehicle type and mode are taken from DOE (1993 through 2004). These figures are used to apportion CO₂ from gasoline, diesel, residual fuel oil, natural gas, and LPG to each mode and vehicle type

Jet fuel consumption estimates are taken directly from DOT (1991 through 2004) for commercial aircraft, from FAA (2004) for general aviation aircraft, and from DESC (2004) for military aircraft. The remainder of jet fuel consumption reported by EIA is assigned as jet fuel consumption from “other aircraft,” and these totals are used to apportion CO₂ from jet fuel. All aviation gasoline is assigned to general aviation aircraft, all residual fuel is assigned to ships and boats, and all electricity is assigned to locomotives and transit cars.

It is important to note that the fuel consumption estimates from EIA (2004) used to calculate CO₂ by fuel type differ from the “bottom up” estimates that are used in the apportionment by mode, some of which also are used in estimating N₂O and CH₄ emissions. In particular, the allocation of transportation diesel fuel and motor gasoline consumption estimates to particular transportation modes may result in lower totals than if an approach using “bottom up” estimates were used. EPA is currently investigating several possible ways to address inconsistencies in data sources in coordination with EIA and FHWA. It should be noted that this is an issue in the apportionment, not in the overall accuracy of the total U.S. estimates of CO₂ from fossil fuel consumption.

Apportionment of CO₂ to Other Mobile Sources

The estimates of N₂O and CH₄ 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 CO₂ from other mobile sources, based on EIA fuel consumption data, are often included in the agricultural, industrial, and

commercial sectors. In order to provide comparable information on transportation and mobile sources, Table 3-36 provides estimates of CO₂ from these other mobile sources. These estimates were developed using the same data sources utilized in developing the N₂O and CH₄ estimates and using the methodology for estimating CO₂ described in Annex 2.1.

Table 3-36: CO₂ Emissions from Non-Transportation Mobile Sources (Tg CO₂ Eq)

	1990	1997	1998	1999	2000	2001	2002	2003
Agricultural Equipment	29.4	37.0	37.1	36.2	36.7	38.8	39.8	40.8
Construction Equipment	37.6	46.7	47.4	48.2	49.6	53.7	55.3	57.0
Other	30.4	32.2	32.9	32.3	33.2	40.0	41.1	42.6
Total	97.5	115.8	117.4	116.7	119.5	132.5	136.3	140.3

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

In order to provide a comprehensive view of greenhouse gas emissions from transportation and other mobile sources, Table 3-37 presents estimates of greenhouse gas emissions for all of the primary greenhouse gas combined, in CO₂ equivalent. The table includes transportation sources, including highway vehicles, aircraft, boats and ships, locomotives and transit rail, which are all mobile sources, as well as pipelines, which are stationary but are used to transport fuel; it also includes other mobile sources, as described above. Sources that are usually classified by EPA as mobile sources but do not have utility associated with their movement, such as handheld garden equipment, are not included in the estimates. These estimates were generated using the emissions reported in Table 3-6, Table 3-21, and Table 3-22 of Chapter 3, Table 3-36 above, as well as some additional estimates calculated specifically for this section. For instance, HFCs from mobile air conditioners and refrigerated transport are captured in Chapter 4.

Although all emissions reported here are based on estimates reported throughout this Inventory, some additional calculations were performed in order to provide a detailed breakdown of emissions by mode and vehicle category. In the case of N₂O and CH₄, additional calculations were performed to develop emissions estimates by type of aircraft and type of heavy-duty vehicle (i.e., heavy-duty trucks or buses) to match the level of detail for CO₂ emissions. N₂O and CH₄ estimates were developed for individual aircraft types by multiplying the emissions estimates for aircraft for each fuel type (jet fuel and aviation gasoline) by the portion of fuel used by each aircraft type (from FAA 1995 through 2004). Similarly, N₂O and CH₄ 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 CO₂), Chapter 4, and Annex 3.8 (for HFCs), and earlier in this Annex (for CH₄ and N₂O).

Table 3-38 presents estimates of GHG emissions from transportation and other mobile sources broken down by greenhouse gas. As this table shows, CO₂ makes up the vast majority of transportation greenhouse gas emissions (approximately 96 percent in 2003), followed by HFCs, N₂O, and CH₄.

GHG Emissions from Freight and Passenger Transportation

Table 3-39, Figure 3-2, Table 3-40, and Figure 3-3, 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 3-39 and Figure 3-2. Freight modes include heavy-duty trucks, freight rail, refrigerated transport, waterborne freight vessels, and pipelines, and are illustrated in Table 3-40 and Figure 3-3. Note that freight trucks (and other freight modes) do carry people, as well as freight (they transport the driver), but these are not typically considered passenger modes. Also, some aircraft do carry some freight, but separating out the emissions associated with freight versus passenger aircraft travel is difficult. To avoid double-counting emissions, this report assigns each of these modes to a single category.

The estimates in these tables and figures are drawn from the estimates in Figure 3-1. In addition, estimates of fuel consumption from DOE (1993 through 2004) were used to allocate rail emissions between passenger and freight categories.

Total emissions from transportation and mobile sources increased by 25 percent between 1990 and 2003. Particularly notable is the rapid increase in emissions from mobile air conditioners and refrigerated transport. In 1990, emissions from these sources were negligible; however, due to the phase-out of ozone-depleting substances (ODSs) under the Montreal Protocol and the Clean Air Act Amendments of 1990,¹ the United States is replacing ODSs, such as chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) with hydrofluorocarbons (HFCs) and other substitutes. While HFCs do not deplete the ozone layer, they are greenhouse gases, so a significant increase in greenhouse gas emissions from mobile air conditioners and refrigerated transport is observed over the 1990 through 2003 timeframe.

In 2003, passenger transportation modes emitted 1,332.8 Tg CO₂ Eq. (66 percent of all transportation and mobile emissions), while freight transportation modes emitted 475.3 Tg CO₂ Eq. (24 percent of all transportation and mobile emissions). 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).

Table 3-37: Total U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (Tg CO₂ Eq.)

Mode / Vehicle Type / Fuel Type	1990	1997	1998	1999	2000	2001	2002	2003	% of Total	% Change 1990-2003
Highway Vehicles	1,196.1	1,363.2	1,402.9	1,442.3	1,460.3	1,468.7	1,490.2	1,504.8	75%	26%
Passenger Cars	640.6	624.1	642.3	650.0	649.7	650.2	662.3	654.6	33%	2%
Gasoline	633.2	618.4	637.1	646.0	646.3	646.7	658.9	651.2	32%	3%
Diesel	7.4	5.6	5.2	4.0	3.4	3.5	3.4	3.4	<1%	-54%
AFVs	+	+	+	+	+	+	+	+	<1%	NE
Light-Duty Trucks	327.7	446.6	457.1	473.9	476.2	477.7	487.6	496.3	25%	51%
Gasoline	316.4	431.1	441.3	457.2	459.3	460.1	470.3	478.4	24%	51%
Diesel	10.8	15.1	15.4	16.3	16.6	17.2	16.9	17.6	1%	64%
AFVs	0.5	0.5	0.4	0.3	0.3	0.3	0.3	0.3	<1%	-39%
Heavy-Duty Trucks	218.2	281.6	292.3	306.1	322.2	329.4	329.4	343.1	17%	57%
Gasoline	38.7	34.7	36.1	37.2	38.7	38.6	40.2	41.1	2%	6%
Diesel	178.6	246.4	255.4	268.3	283.0	290.2	288.6	301.4	15%	69%
AFVs	0.9	0.5	0.7	0.6	0.5	0.6	0.7	0.6	<1%	-26%
Buses	7.9	9.2	9.4	10.4	10.3	9.7	9.2	9.0	<1%	15%
Gasoline	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	<1%	-2%
Diesel	7.5	8.6	8.7	9.7	9.4	8.8	8.2	8.0	<1%	7%
AFVs	+	0.2	0.3	0.4	0.5	0.5	0.7	0.7	<1%	NE
Motorcycles	1.7	1.8	1.8	1.8	1.8	1.7	1.7	1.7	<1%	-4%
Gasoline	1.7	1.8	1.8	1.8	1.8	1.7	1.7	1.7	<1%	-4%
Aircraft	179.1	180.9	183.2	188.7	195.2	185.3	176.8	173.1	9%	-3%
General Aviation										
Aircraft	9.5	8.9	10.3	12.0	11.8	11.6	11.8	11.8	1%	24%
Jet Fuel	6.4	6.1	7.8	9.3	9.3	9.1	9.4	9.5	<1%	49%
Aviation Gasoline	3.1	2.8	2.5	2.7	2.5	2.4	2.4	2.3	<1%	-27%
Commercial Aircraft	118.4	129.8	127.6	137.9	142.1	134.2	123.0	124.0	6%	5%
Jet Fuel	118.4	129.8	127.6	137.9	142.1	134.2	123.0	124.0	6%	5%
Military Aircraft	35.1	21.2	21.7	20.8	21.2	23.1	20.6	20.8	1%	-41%
Jet Fuel	35.1	21.2	21.7	20.8	21.2	23.1	20.6	20.8	1%	-41%
Other Aircraft^a	16.1	20.9	23.6	18.0	20.1	16.6	21.4	16.5	1%	3%
Jet Fuel	16.1	20.9	23.6	18.0	20.1	16.6	21.4	16.5	1%	3%
Boats and Ships	49.6	39.1	32.7	42.7	63.7	43.2	57.8	58.0	3%	17%
Gasoline	9.5	11.3	11.3	11.2	11.3	11.3	11.2	11.2	1%	17%
Distillate Fuel	16.5	17.1	15.2	17.6	17.5	19.3	18.5	17.1	1%	4%
Residual Fuel	23.6	10.8	6.2	13.8	34.9	12.6	28.0	29.7	1%	26%
Locomotives and Other										
Rail	36.6	40.4	40.9	42.0	42.1	43.2	41.4	43.2	2%	18%
Distillate Fuel	33.6	37.4	37.8	38.9	38.8	39.8	38.3	40.0	2%	19%

¹ [42 U.S.C § 7671, CAA § 601]

Electricity	3.0	3.1	3.1	3.2	3.4	3.4	3.2	3.2	<1%	7%
Pipelines^b	35.9	40.9	34.9	35.3	35.0	33.4	36.4	34.8	2%	-3%
Natural Gas	35.9	40.9	34.9	35.3	35.0	33.4	36.4	34.8	2%	-3%
Agricultural Equipment	29.8	37.4	37.6	36.6	37.1	39.2	40.3	41.3	2%	39%
Gasoline	7.2	8.7	8.0	6.2	5.7	7.1	7.3	7.5	<1%	4%
Diesel	22.6	28.7	29.6	30.4	31.3	32.1	32.9	33.7	2%	50%
Construction Equipment	38.0	47.1	47.9	48.7	50.1	54.2	55.8	57.5	3%	52%
Gasoline	3.5	3.3	2.7	2.2	2.3	5.0	5.3	5.6	<1%	60%
Diesel	34.5	43.9	45.2	46.5	47.8	49.2	50.6	51.9	3%	51%
Other Mobile Sources^c	30.7	32.5	33.2	32.6	33.5	40.4	41.5	42.9	2%	40%
Gasoline	24.1	24.4	24.9	24.2	24.8	31.4	32.3	33.5	2%	39%
Diesel	6.6	8.1	8.3	8.4	8.7	9.0	9.2	9.5	<1%	44%
Mobile Air Conditioning	+	19.4	24.4	29.3	33.8	37.4	40.4	42.7	2%	NA
Refrigerated Transport	+	13.8	17.4	20.8	24.0	26.7	28.8	30.3	2%	NA
Lubricants	+	5.5	7.0	8.5	9.8	10.8	11.5	12.3	1%	NA
Total	11.9	11.6	12.1	12.3	12.1	11.1	10.9	10.2	1%	-14%

^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 CO₂ from natural gas used to power pipelines; does not include emissions from electricity use or non-CO₂ 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 CO₂ Eq.

NE = Not Estimated, because emissions in 1990 were insignificant.

Table 3-38: Transportation and Mobile Source Emissions by Gas (Tg CO₂ Eq.)

	1990	1997	1998	1999	2000	2001	2002	2003	% of Total	% Change 1990-2003
CO ₂	1,559.2	1,733.8	1,766.1	1,822.9	1,872.7	1,866.7	1,902.6	1,921.0	95.6%	23%
N ₂ O	43.7	55.2	55.3	54.6	53.2	49.0	45.6	42.1	2.1%	-4%
CH ₄	4.8	4.0	3.9	3.6	3.4	3.1	2.9	2.7	0.1%	-44%
HFC	+	19.4	24.4	29.3	33.8	37.4	40.4	42.7	2.1%	NE
Total	1,607.7	1,812.4	1,849.7	1,910.4	1,963.0	1,956.2	1,991.5	2,008.4	100.0%	25%

Figure 3-1: Domestic Greenhouse Gas Emissions by Mode and Vehicle Type, 1990 to 2003 (Tg CO₂ Eq.)

* "Other" includes pipelines, refrigerated transport; and agricultural, construction, airport, commercial, recreational, logging, lawn and garden, railroad, and industrial equipment.

Table 3-39: Greenhouse Gas Emissions from Passenger Transportation (Tg CO₂ Eq.)

Vehicle Type	1990	1997	1998	1999	2000	2001	2002	2003	% Change 1990-2003
Highway Vehicles	976.2	1,079.9	1,108.8	1,134.3	1,136.2	1,137.6	1,159.1	1,160.0	19%
Passenger Cars	640.6	624.1	642.3	650.0	649.7	650.2	662.3	654.6	2%
Light-duty Trucks	327.7	446.6	457.1	473.9	476.2	477.7	487.6	496.3	51%
Buses	7.9	9.2	9.4	10.4	10.3	9.7	9.2	9.0	15%
Aircraft	127.9	138.7	137.9	149.9	153.9	145.7	134.8	135.8	6%
General Aviation	9.5	8.9	10.3	12.0	11.8	11.6	11.8	11.8	24%
Commercial Aviation	118.4	129.8	127.6	137.9	142.1	134.2	123.0	124.0	5%
Recreational Boats	9.5	11.3	11.3	11.2	11.3	11.3	11.2	11.2	17%
Passenger Rail	4.2	4.4	4.5	4.6	4.9	5.1	4.9	5.0	18%
Mobile Air Conditioners	+	13.8	17.4	20.8	24.0	26.7	28.8	30.3	NA
Total	1,117.8	1,248.1	1,279.9	1,320.8	1,330.3	1,326.4	1,338.8	1,342.3	20%

+ Less than 0.05 Tg CO₂ Eq.

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

Figure 3-2: Greenhouse Gas Emissions from Passenger Transportation by Mode, 1990 to 2003 (Tg CO₂ Eq.)

Table 3-40: Greenhouse Gas Emissions from Domestic Freight Transportation (Tg CO₂ Eq.)

By Mode	1990	1997	1998	1999	2000	2001	2002	2003	% Change 1990-2003
Trucking	218.2	281.6	292.3	306.1	322.2	329.4	329.4	343.1	57%
Rail	32.4	36.0	36.4	37.5	37.2	38.2	36.6	38.2	18%
Waterborne	40.1	27.8	21.4	31.4	52.4	31.9	46.5	46.9	17%
Refrigerated Transport	0.0	5.5	7.0	8.5	9.8	10.8	11.5	12.3	NA
Pipelines	35.9	40.9	34.9	35.3	35.0	33.4	36.4	34.8	-3%
Total	326.6	391.84	391.99	418.76	456.72	443.63	460.50	475.29	46%

+ Less than 0.05 Tg CO₂ 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) was used to allocate the passenger/freight split of rail emissions.

Figure 3-3: Greenhouse Gas Emissions from Domestic Freight Transportation by Mode, 1990 to 2003 (Tg CO₂ Eq.)

3.3. Methodology for Estimating CH₄ 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 emissions¹ 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 2003, 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 3-41. 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 3-41). The proportion was then applied to the years 1990 through 2003 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 - 2003, 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.

¹ MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

Table 3-41: Mine-Specific Data Used to Estimate Ventilation Emissions

Year	Individual Mine Data Used
1990	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1991	1990 Emissions Factors Used Instead of Mine-Specific Data
1992	1990 Emissions Factors Used Instead of Mine-Specific Data
1993	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1994	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1995	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1996	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1997	All Mines with Detectable Emissions (Assumed to Account for 100% of Total)
1998	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1999	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2000	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2001	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2002	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2003	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*

* 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 2003, eleven active coal mines had methane recovery and use projects, ten sold the recovered methane to a pipeline and one used the methane on site. 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 3-42, 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 3-42. 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 3-43 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 3-44 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 3-45 and Table 3-46 present estimates of methane liberated, used, and emitted for 1990 through 2003. Table 3-47 provides emissions by state.

Table 3-42: 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 3-43: Annual Coal Production (Thousand Short Tons)*Underground Coal Production*

Basin	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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
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
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
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
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
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
West Interior	105	26	59	100	147	25	137	212	247	200	241	416	464	394
Northwest	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	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

Surface Coal Production

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

Total Coal Production

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

Source for 1990-2003 data: EIA (1990-03), Coal Industry Annual. U.S. Department of Energy, Washington, DC, Table 3.

Note: Totals may not sum due to independent rounding.

Table 3-44: Coal Surface and Post-Mining Methane Emission Factors (ft³ per Short Ton)

Basin	Surface Average <i>in situ</i> Content	Underground Average <i>In situ</i> Content	Surface Mine Factors	Post-Mining Surface Factors	Post Mining Underground
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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 3-45: Underground Coal Mining Methane Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Ventilation Output	112	NA	NA	95	96	97	90	96	94	92	87	84	79	76
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%
Adjusted Ventilation Output	114	NA	NA	97	98	106	99	96	96	94	89	86	80	77
Degasification System Liberated	54	NA	NA	45	46	44	50	42	49	41	45	48	52	56
Total Underground Liberated	167	164	162	142	144	150	149	138	146	135	134	135	132	133
Recovered & Used	(14)	(15)	(16)	(23)	(28)	(30)	(36)	(28)	(35)	(32)	(36)	(40)	(43)	(40)
Total	154	150	146	119	117	120	113	110	110	103	98	95	89	93

^{*} Refer to Table 3-41.

Note: Totals may not sum due to independent rounding.

Table 3-46: Total Coal Mining Methane Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Underground Mining	154	149	144	119	117	120	113	110	110	103	98	95	89	93
Surface Mining	26	24	24	23	23	22	23	23	23	22	22	23	22	21
Post-Mining (Underground)	19	18	18	16	17	17	18	18	18	17	17	17	16	16
Post-Mining (Surface)	4	4	4	4	4	4	4	4	4	4	4	4	4	3
Total	203	196	191	162	16	163	157	156	156	146	140	138	130	134

Note: Totals may not sum due to independent rounding.

Table 3-47: Total Coal Mining Methane Emissions by State (Million Cubic Feet)

State	1990	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Alabama	32,313	25,927	29,595	31,921	29,229	25,731	26,401	25,653	23,554	22,147	19,252	20,530
Alaska	22	21	20	22	19	19	17	20	21	20	15	14
Arizona	192	207	222	203	177	199	192	200	223	228	217	205
Arkansas	7	8	8	5	4	3	4	4	2	2	2	1
California	1	0	0	0	0	0	0	0	0	0	0	0
Colorado	10,325	7,225	9,192	8,663	5,960	9,189	9,181	9,390	10,784	11,117	12,082	13,216
Illinois	10,502	8,684	10,585	11,084	10,850	8,534	7,847	7,810	8,521	7,270	5,972	4,744
Indiana	2,795	2,334	2,495	1,866	2,192	2,742	2,878	2,650	2,231	3,373	3,496	3,821
Iowa	30	14	4	0	0	0	0	0	0	0	0	0
Kansas	57	27	23	23	19	29	27	33	16	14	16	12
Kentucky	10,956	10,111	11,259	9,748	8,978	10,451	10,005	9,561	9,056	9,363	8,464	8,028
Louisiana	245	241	267	286	248	273	247	227	284	286	293	310
Maryland	519	228	237	237	259	267	251	225	331	340	401	391
Mississippi	-	0	0	0	0	0	0	1	57	43	165	264
Missouri	211	52	67	44	57	32	30	31	35	29	20	43
Montana	490	468	542	514	492	534	558	535	449	510	487	481
New Mexico	451	641	679	466	408	459	489	497	464	630	1,280	1,832
North Dakota	380	416	420	392	389	385	389	405	407	397	401	410
Ohio	5,065	4,393	4,583	4,029	4,064	4,349	4,350	3,914	3,515	3,619	2,831	2,649
Oklahoma	285	298	359	323	286	385	395	469	453	620	660	620
Pennsylvania	22,735	26,436	24,024	26,995	26,382	30,026	29,491	23,626	22,253	22,253	19,667	23,949
Tennessee	296	104	101	112	143	148	116	119	99	142	142	124
Texas	4,291	4,199	4,028	4,054	4,245	4,104	4,047	4,084	3,732	3,466	3,482	3,657
Utah	3,587	3,505	2,616	2,410	2,805	3,566	3,859	3,633	2,811	2,081	2,709	3,408
Virginia	46,137	30,387	26,742	19,820	19,675	16,851	13,978	13,321	11,981	11,506	11,227	10,067
Washington	65	62	64	63	59	59	60	53	56	60	76	81
West Virginia	49,039	33,110	30,588	36,657	36,307	33,572	36,962	35,416	31,311	33,745	31,981	29,813
Wyoming	2,385	2,719	3,065	3,419	3,604	3,652	4,080	4,376	4,408	4,801	4,859	4,899
Total	203,381	161,817	161,784	163,356	156,851	155,559	155,856	146,255	139,625	138,062	130,197	133,560

+ 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 CH₄ Emissions from Natural Gas Systems

The following steps were used to estimate CH₄ 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 GRI/EPA (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 3-48 displays the 1992 GRI/EPA activity levels and emission factors for venting and flaring from the field production 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 2003, activity levels were estimated using aggregate statistics on key drivers, including: number of producing wells (API 2002-3, EIA 2001a, 2002a, 2003e), number of gas plants (AGA 1991-1998; OGJ 1999-2004), miles of transmission pipeline (OPS 2004a), miles of distribution pipeline (OPS 2004b), miles of distribution services (OPS 2004b), energy consumption (EIA 1993, 1996a, 1997a, 1998a, 2001b, 200e, 2003c, 2004c). 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 3-49 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 reduction 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 emissions estimate for that source. Total Inventory 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). We also adjust the reductions to remove the sunseting time period, which removes reductions from the accounting system after a set time period. In future inventories, the sunseting may be replaced with a technological lifetime.

Table 3-51 illustrates emission estimates from the field production stage. Table 3-52 presents total natural gas production and associated methane emissions. Methane reductions derived from the Natural Gas STAR program for the years 1992 through 2003 are presented in Table 3-50.

Table 3-48: 1992 Data and Emissions (Gg) for Venting and Flaring from Natural Gas Field Production Stage

Activity	GRI/EPA Values			EPA Adjusted Values		
	Activity Data	Emission Factor	Emissions	Activity Data	Emission Factor	Emissions
Drilling and Well Completion						
Completion Flaring	844 compl/yr	733 Scf/comp	0.01	400 compl/yr	733 scf/comp	0.01
Well Drilling	-	-	-	11,169 wells drilled/yr	2,543 scf/well	0.55
Coal Bed Methane						
Powder River	-	-	-	145,975,197 gallon water drainage/yr	2.05E-09 Gg/gallon water drainage	0.30
Black Warrior	-	-	-	2,230 wells	0.00207 Gg/well	4.61
Normal Operations						
Pneumatic Device Vents	249,111 controllers	345 scfd/device	604.17	249,111 controllers	345 scfd/device	604.17
Chemical Injection Pumps	16,971 active pumps	248 scfd/pump	29.59	22,389 active pumps	248 scfd/pump	39.04
Kimray Pumps	11,050,000 MMscf/yr	992 scf/MMscf	211.12	7,365,914 MMscf/yr	992 scf/MMscf	140.73
Dehydrator Vents	12,400,000 MMscf/yr	276 scf/MMscf	65.81	8,184,349 MMscf/yr	276 scf/MMscf	43.44
GoM Offshore Flaring	-	-	-	2 % CH4	4,029 MMscf/yr	1.49
GoM Offshore Well Venting	-	-	-	96 % CH4	7,164 MMscf/yr	132.45
Condensate Tank Vents						
Condensate Tanks without Control Devices	-	-	-	74 MMbbl/yr	21.87 scf/bbl	30.96
Condensate Tanks with Control Devices	-	-	-	74 MMbbl/yr	4.37 scf/bbl	6.19
Compressor Exhaust Vented Gas Engines	27,460 MMHPHr	0.24 scf/HPHr	126.93	27,460 MMHPHr	0.24 scf/HPHr	126.93
Routine Maintenance						
Well Workovers						
Gas Wells	9,392 w.o./yr	2,454 scfy/w.o.	0.44	11,780 w.o./yr	2,454 scfy/w.o.	0.56
Well Clean Ups (LP Gas Wells)	114,139 LP gas wells	49,570 scfy/LP well	108.97	111,031 LP gas wells	49,570 scfy/LP well	106.00
Blowdowns						
Vessel BD	255,996 vessels	78 scfy/vessel	0.39	180,504 vessels	78 scfy/vessel	0.27
Pipeline BD	340,000 miles (gath)	309 scfy/mile	2.02	298,035 miles (gath)	309 scfy/mile	1.77
Compressor BD	17,112 compressors	3,774 scfy/comp	1.24	22,453 compressors	3,774 scfy/comp	1.63
Compressor Starts	17,112 compressors	8,443 scfy/comp	2.78	22,453 compressors	8,443 scfy/comp	3.65
Upsets						
Pressure Relief Valves	529,440 PRV	34.0 scfy/PRV	0.35	529,440 PRV	34.0 scfy/PRV	0.35
ESD	1,115 platforms	256,888 scfy/plat	5.52	2,228 platforms	256,888 scfy/plat	11.02
Mishaps	340,000 miles	669 scfy/mile	4.38	74,509 miles	669 scfy/mile	0.96

Table 3-49: Activity Factors for Key Drivers

Variable	Units	1990	1997	1998	1999	2000	2001	2002	2003
Transmission Pipelines Length	miles	291,990	294,370	302,709	296,114	298,944	290,502	304,107	285,165

Wells									
GSAM Appalachia Wells*	# wells	120,443	120,037	117,878	118,723	135,065	140,171	145,115	145,115
GSAM N Central Associated Wells*	# wells	3,780	3,409	3,361	3,275	2,439	2,278	2,229	2,196
GSAM N Central Non-Associated Wells*	# wells	3,277	8,910	8,917	8,800	9,113	9,517	9,745	9,745
GSAM Rest of US Wells*	# wells	145,380	182,024	190,134	174,898	197,500	223,346	228,766	228,766
GSAM Rest of US Associated Wells*	# wells	270,958	264,385	254,848	251,686	245,967	244,168	243,774	239,867
Appalachia. + N. Central Non-Assoc. + Rest of US	# wells	269,100	310,971	316,929	302,421	341,678	373,034	383,626	383,626
N. Central Non-Assoc. + Rest of US Wells	# wells	148,657	190,934	199,051	183,698	206,613	232,863	238,511	238,511
Platforms									
Gulf of Mexico Off-shore Platforms	# platforms	3,915	3,961	4,036	3,999	4,003	4,057	4,049	4,004
Rest of U.S. (offshore platforms)	# platforms	24	23	23	23	23	23	23	23
Gas Plants	# gas plants	761	615	558	581	585	570	590	574
Distribution Services	# of services	43,065,846	53,895,713	54,035,004	54,317,439	56,555,782	57,511,048	60,753,920	48,241,687
Steel – Unprotected	# of services	5,500,993	5,518,795	5,463,253	5,751,250	5,675,373	5,469,468	5,328,485	4,154,292
Steel - Protected	# of services	19,916,202	19,078,467	18,478,344	18,310,719	17,786,955	17,899,877	18,120,504	13,424,376
Plastic	# of services	16,269,414	27,800,401	28,629,388	28,796,952	31,659,363	32,741,971	35,777,119	29,489,409
Copper	# of services	1,379,237	1,498,050	1,464,019	1,458,518	1,434,091	1,399,732	1,527,812	1,173,610
Distribution Mains	miles	837,300	997,486	1,019,816	1,004,907	1,044,473	1,098,545	1,141,759	1,016,782
Cast Iron	miles	52,644	47,669	47,587	45,865	44,726	44,404	45,523	35,937
Steel – Unprotected	miles	91,267	85,166	86,639	84,534	82,855	81,273	82,610	61,830
Steel – Protected	miles	491,120	479,278	484,963	459,298	469,306	475,016	487,667	505,501
Plastic	miles	202,269	385,373	400,627	415,210	447,586	497,852	525,959	413,514

* GSAM (Gas Systems Analysis Model) is a natural gas supply, demand, and transportation model used by the Federal Energy Technology Center of the U.S. Department of Energy (GSAM 1997).

Table 3-50: Methane reductions derived from the Natural Gas STAR program (Gg)

Process	1997	1998	1999	2000	2001	2002	2003
Production	175	216	255	305	370	414	456
Processing	7	8	11	12	15	20	22
Transmission and Storage	140	210	252	300	379	384	355
Distribution	33	26	24	21	27	186	132

Note: These reductions will not match the Natural Gas STAR program reductions. These numbers are adjusted for reductions prior to 1992, and do not include a sunseting period.

Table 3-51: CH₄ Emission Estimates from the Field Production Stage (Gg)

Activity	1990	1997	1998	1999	2000	2001	2002	2003
Drilling and Well Completion								
Completion Flaring	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Well Drilling	0.73	0.70	0.69	0.65	0.94	1.23	0.92	1.11
Coal Bed Methane								
Powder River	0.08	5.86	9.36	20.33	48.69	66.44	74.99	73.38
Black Warrior	2.69	5.74	5.87	5.94	6.06	6.50	6.95	7.59
Normal Operations								
Pneumatic Device Vents	591.52	759.74	792.04	730.95	822.13	926.58	949.05	949.05
Chemical Injection Pumps	37.82	49.31	51.12	46.94	51.95	57.38	57.75	56.97
Kimray Pumps	137.65	157.69	160.24	152.24	170.74	184.22	187.41	185.82
Dehydrator Vents	42.49	48.67	49.46	46.99	52.70	56.86	57.85	57.35
GoM Offshore Flaring	1.81	1.88	1.93	1.61	1.49	1.42	1.43	1.43
GoM Offshore Well Venting	161.05	191.27	204.69	179.34	165.66	165.96	167.12	166.73
Condensate Tank Vents								
Condensate Tanks without Control Devices	33.28	36.65	37.49	41.91	43.81	45.28	43.60	43.60
Condensate Tanks with Control Devices	6.66	7.33	7.50	8.38	8.76	9.06	8.72	8.72
Compressor Exhaust Vented								
Gas Engines	124.27	159.61	166.40	153.56	172.72	194.66	199.39	199.39
Routine Maintenance								
Well Workovers								
Gas Wells	0.54	0.62	0.63	0.60	0.68	0.73	0.74	0.74
Well Clean Ups (LP Gas Wells)	103.68	118.78	120.70	114.67	128.61	138.76	141.16	139.96
Blowdowns								
Vessel BD	0.27	0.33	0.34	0.31	0.35	0.38	0.38	0.38
Pipeline BD	1.75	2.00	2.04	1.93	2.10	2.25	2.27	2.25
Compressor BD	1.60	1.93	1.99	1.87	2.10	2.33	2.40	2.40
Compressor Starts	3.59	4.32	4.46	4.18	4.70	5.22	5.36	5.36
Upsets								
Pressure Relief Valves	0.34	0.44	0.45	0.42	0.47	0.53	0.54	0.54
ESD	10.74	11.61	11.94	11.94	12.06	12.33	12.42	12.39
Mishaps	0.95	1.08	1.10	1.05	1.14	1.22	1.23	1.22

Table 3-52: U.S. Total Natural Gas Production (Trillion Ft³/yr) and Associated CH₄ Emissions (Gg)

Activity	1990	1997	1998	1999	2000	2001	2002	2003
Production	17.8	18.9	19.0	18.8	19.2	19.6	19.0	19.1
CH ₄ Emissions from Production	1,731	1,921	1,962	1,785	1,953	2,117	2,121	2,068

3.5. Methodology for Estimating CH₄ Emissions from Petroleum Systems

The methodology for estimating methane 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). Seventy activities that emit methane from petroleum systems were examined from these reports. Most of the activities analyzed involve crude oil production field operations, which accounted for about 96 percent of total oil industry emissions. Crude transportation and refining accounted for the remaining emissions of one and three percent, respectively.

The following steps were taken to estimate methane emissions from petroleum systems.

Step 1: Determine Emission Factors for all Activities

The emission factors for sixty-six of the seventy activities for 1995 are taken from the 1999 EPA draft report, which contained the most recent and comprehensive determination of methane emission factors for the seventy methane 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. Gas engine emissions factor is taken from Radian (1996b). Oil Tank venting emissions factor taken from the API E&P Tank Calc average for API gravity less than 44 deg. The emission factors determined for 1995 were assumed to be representative of emissions from each source type over the period 1990 through 2003. 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 fifty-seven activities, activity levels for 1995 are taken from EPA (1999). For the remaining thirteen activities, the activity levels for 1993 are taken from Radian (1996e). These thirteen activity levels were derived from field data collected in 1993, along with 1993 crude oil production and number of wells.

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 relative to the base years (1993 and 1995). 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 2003. 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, 2003 data were not yet available. In these cases, the 2002 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 70 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 methane emissions. Table 3-53, Table 3-54, and Table 3-55 provide 2003 activity factors, emissions factors and emission estimates. Table 3-56 provides a summary of emissions estimates for the years 1990 through 2003.

Table 3-53: 2003 CH₄ Emissions from Petroleum Production Field Operations

Activity/Equipment	Emission		Activity		Emissions (Bcf/yr)
	Factor	Units	Factor	Units	
Vented Emissions					33.661
Oil Tanks	5.28	scf of CH ₄ /bbl crude	1,492	MMbbl/yr (non stripper wells)	7.877

Activity/Equipment	Emission		Activity		Emissions (Bcf/yr)
	Factor	Units	Factor	Units	
Pneumatic Devices, High Bleed	330	scfd CH ₄ /device	139,121	No. of high-bleed devices	16.777
Pneumatic Devices, Low Bleed	52	scfd CH ₄ /device	258,367	No. of low-bleed devices	4.904
Chemical Injection Pumps	248	scfd CH ₄ /pump	27,791	No. of pumps	2.516
Vessel Blowdowns	78	scfy CH ₄ /vessel	181,670	No. of vessels	0.014
Compressor Blowdowns	3,775	scf/yr of CH ₄ /compressor	2,467	No. of compressors	0.009
Compressor Starts	8,443	scf/yr. of CH ₄ /compressor	2,467	No. of compressors	0.021
Stripper wells	2,345	scf/yr of CH ₄ /stripper well	321,658	No. of stripper wells vented	0.754
Well Completion Venting	733	scf/completion	6,199	Oil well completions	0.005
Well Workovers	96	scf CH ₄ /workover	38,925	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, Gulf of Mexico	1,382	scfd CH ₄ /platform	1,522	No. of oil platforms	0.768
Offshore Platforms, Other U.S. Areas	1,382	scfd CH ₄ /platform	23	No. of oil platforms	0.012
Fugitive Emissions					2.506
Offshore Platforms, Gulf of Mexico	60	scfd CH ₄ /platform	1,522	No. of oil platforms	0.033
Offshore Platforms, Other U.S. Areas	60	scfd CH ₄ /platform	23	No. of oil platforms	0.001
Oil Wellheads (heavy crude)	0.13	scfd/well	13,913	No. of hvy. crude wells	0.001
Oil Wellheads (light crude)	16.6	scfd/well	183,430	No. of lt. crude wells	1.113
Separators (heavy crude)	0.15	scfd CH ₄ /separator	10,683	No. of hvy. crude seps.	0.001
Separators (light crude)	14	scfd CH ₄ /separator	97,226	No. of lt. crude seps.	0.492
Heater/Treaters (light crude)	19	scfd CH ₄ /heater	73,761	No. of heater treaters	0.517
Headers (heavy crude)	0.08	scfd CH ₄ /header	13,538	No. of hvy. crude hdrs.	0.000
Headers (light crude)	11	scfd CH ₄ /header	41,970	No. of lt. crude hdrs.	0.166
Floating Roof Tanks	338,306	scf CH ₄ /floating roof tank/yr.		No. of floating roof tanks	
			24		0.008
Compressors	100	scfd CH ₄ /compressor	2,467	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	1,744,725	Loadings/year	0.071
Pipelines	0	scfd of CH ₄ /mile of pipeline	16,214	Miles of gathering line	0.000
Well Drilling	0	scfd of CH ₄ /oil well drilled	7,061	No. of oil wells drilled	0.000
Battery Pumps	0.24	scfd of CH ₄ /pump	155,700	No. of battery pumps	0.014
Combustion Emissions					4.022
Gas Engines	0.24	scf CH ₄ /HP-hr	15,539	MMHP-hr	3.729
Heaters	0.52	scf CH ₄ /bbl	2094.0	MBbl/yr	0.001
Well Drilling	2,453	scf CH ₄ /well drilled	7,061	Oil wells drilled	0.017
Flares	20	scf CH ₄ /Mcf flared	173,304	Mcf flared/yr	0.003
Offshore Platforms, Gulf of Mexico	481	scfd CH ₄ /platform	1,522	No. of oil platforms	0.267
Offshore Platforms, Other U.S. Areas	481	scfd CH ₄ /platform	23	No. of oil platforms	0.004
Process Upset Emissions					0.473
Platform Emergency Shutdowns	256,888	scfy/platform	1,545	No. of platforms	0.397
Pressure Relief Valves	35	scf/yr/PR valve	174,912	No. of PR valves	0.006
Well Blowouts Offshore	5.0	MMscf/blowout	2.25	No. of blowouts/yr	0.011
Well Blowouts Onshore	2.5	MMscf/blowout	23.5	No. of blowouts/yr	0.059
Total					40.66

Note: These estimates do not include emission reductions reported by the Natural Gas STAR Program.

Table 3-54: 2003 CH₄ Emissions from Petroleum Transportation

Activity/Equipment	Emission		Activity		Emissions (Bcf/yr)
	Factor	Units	Factor	Units	
Vented Emissions					0.223
Tanks	0.021	scf CH ₄ /yr/bbl of crude delivered to refineries	5,586	MMbbl crude feed/yr	0.115
Truck Loading	0.520	scf CH ₄ /yr/bbl of crude transported by truck	53.5	MMbbl trans. by truck	0.028
Marine Loading	2.544	scf CH ₄ /1000 gal. crude marine loadings	24,065,786	1,000 gal./yr loaded	0.061
Rail Loading	0.520	scf CH ₄ /yr/bbl of crude transported by rail	7.6	MMbbl. Crude by rail/yr	0.004
Pump Station Maintenance	36.80	scf CH ₄ /station/yr	529	No. of pump stations	0.000
Pipeline Pigging	39	scfd of CH ₄ /pig station	1,057	No. of pig stations	0.015
Fugitive Emissions					0.050
Pump Stations	25	scfCH ₄ /mile/yr.	52,854	No. of miles of crude p/l	0.001
Pipelines	0	scf CH ₄ /bbl crude transported by pipeline	7,019	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

Activity/Equipment	Emission		Activity		Emissions (Bcf/yr)
	Factor	Units	Factor	Units	
Combustion Emissions					0.000
Pump Engine Drivers	0.24	scf CH ₄ /hp-hr	NA	No. of hp-hrs	NA
Heaters	0.521	scf CH ₄ /bbl.burned	NA	No. of bbl. Burned	NA
Total					0.273

Table 3-55: 2003 CH₄ Emissions from Petroleum Refining

Activity/Equipment	Emission		Activity		Emissions (Bcf/yr)
	Factor	Units	Factor	Units	
Vented Emissions					1.242
Tanks	20.6	scfCH ₄ /Mbbbl	1,963	Mbbbl/cd heavy crude feed	0.015
System Blowdowns	137	scfCH ₄ /Mbbbl	15,304	Mbbbl/cd refinery feed	0.764
Asphalt Blowing	2,555	scfCH ₄ /Mbbbl	496	Mbbbl/cd production	0.463
Fugitive Emissions					0.088
Fuel Gas System	439	McfCH ₄ /refinery/yr	146	Refineries	0.064
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 /Mbbbl	15,304	Mbbbl/cd refinery feed	0.011
Cooling Towers	2.36	scfCH ₄ /Mbbbl	15,304	Mbbbl/cd refinery feed	0.013
Combustion Emissions					0.095
Atmospheric Distillation	3.61	scfCH ₄ /Mbbbl	15,508	Mbbbl/cd refinery feed	0.020
Vacuum Distillation	3.61	scfCH ₄ /Mbbbl	6,888	Mbbbl/cd feed	0.009
Thermal Operations	6.02	scfCH ₄ /Mbbbl	2,144	Mbbbl/cd feed	0.005
Catalytic Cracking	5.17	scfCH ₄ /Mbbbl	5,221	Mbbbl/cd feed	0.010
Catalytic Reforming	7.22	scfCH ₄ /Mbbbl	3,246	Mbbbl/cd feed	0.009
Catalytic Hydrocracking	7.22	scfCH ₄ /Mbbbl	1,311	Mbbbl/cd feed	0.003
Hydrotreating	2.17	scfCH ₄ /Mbbbl	2,013	Mbbbl/cd feed	0.002
Hydrotreating	6.50	scfCH ₄ /Mbbbl	9,232	Mbbbl/cd feed	0.022
Alkylation/Polymerization	12.6	scfCH ₄ /Mbbbl	1,099	Mbbbl/cd feed	0.005
Aromatics/Isomeration	1.80	scfCH ₄ /Mbbbl	997	Mbbbl/cd feed	0.001
Lube Oil Processing	0.00	scfCH ₄ /Mbbbl	158	Mbbbl/cd feed	0.000
Engines	0.006	scfCH ₄ /hp-hr	1,467	MMhp-hr/yr	0.008
Flares	0.189	scfCH ₄ /Mbbbl	15,304	Mbbbl/cd refinery feed	0.001
Total					1.425

Table 3-56: Summary of CH₄ Emissions from Petroleum Systems (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Production Field Operations	920	933	902	881	870	861	861	862	846	815	803	799	783	782
Pneumatic device venting	545	556	537	527	524	516	516	515	504	488	478	475	465	465
Tank venting	179	179	173	167	161	161	161	164	162	153	154	154	151	151
Combustion & process upsets	103	105	101	98	97	96	96	96	94	90	89	89	87	86
Misc. venting & fugitives	66	67	66	65	64	63	63	62	61	60	59	59	58	57
Wellhead fugitives	26	26	24	24	24	25	25	25	25	24	22	22	21	21
Crude Oil Transportation	7	6	6	6	6	6	6	6	6	6	5	5	5	5
Refining	25	24	24	25	25	25	26	27	27	27	28	27	27	27
Total	951	964	932	912	901	893	893	895	879	848	836	831	815	815

3.6. Methodology for Estimating CO₂ and N₂O Emissions from Municipal Solid Waste Combustion

Emissions of CO₂ from municipal solid waste (MSW) combustion include CO₂ 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 N₂O. The methodology for calculating emissions from each of these waste combustion sources is described in this Annex.

CO₂ from Plastics Combustion

In the *Characterization of Municipal Solid Waste in the United States* reports (EPA 1997, 1998, 1999, 2000c, 2002, 2003), the flows of plastics in the U.S. waste stream are reported for seven resin categories. For 2001, the most recent year for which these data are reported, the quantity generated, recovered, and discarded for each resin is shown in Table 3-57. The data set for 1990 through 2003 is incomplete, and several assumptions were employed to bridge the data gaps. The EPA reports do not provide estimates for individual materials landfilled and combusted, although they do provide such an estimate for the waste stream as a whole. To estimate the quantity of plastics landfilled and combusted, total discards were apportioned based on the proportions of landfilling and combustion for the entire U.S. waste stream for each year in the time series. For those years when distribution by resin category was not reported (1990-1994), total values were apportioned according to 1995 (the closest year) distribution ratios. Generation and recovery figures for 2002 and 2003 are held constant at the year 2001 level.

Table 3-57: 2001 Plastics in the Municipal Solid Waste Stream by Resin (Gg)

Waste Pathway	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Generation	2,341	4,463	1,288	5,334	3,139	2,077	4,382	23,025
Recovery	426	390	0	136	9	0	299	1,261
Discard	1,914	4,073	1,288	5,198	3,130	2,077	4,082	21,764
Landfill	1,514	3,222	1,019	4,111	2,475	1,643	3,229	17,213
Combustion	400	852	269	1,087	654	434	854	4,551
Recovery*	18%	9%	0%	3%	0%	0%	7%	5%
Discard*	82%	91%	100%	97%	100%	100%	93%	95%
Landfill*	65%	72%	79%	77%	79%	79%	74%	75%
Combustion*	17%	19%	21%	20%	21%	21%	19%	20%

*As a percent of waste generation.

Note: Totals may not sum due to independent rounding. Abbreviations: PET (polyethylene terephthalate), HDPE (high density polyethylene), PVC (polyvinyl chloride), LDPE/LLDPE (linear low density polyethylene), PP (polypropylene), PS (polystyrene).

Fossil fuel-based CO₂ emissions were calculated as the product of plastic combusted, carbon content, and fraction oxidized (see Table 3-58, which shows calculations for 2001). 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 3-58: 2001 Plastics Combusted (Gg), Carbon Content (%), Fraction Oxidized (%) and Carbon Combusted (Gg)

Factor	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Quantity Combusted (Gg)	400	852	269	1,087	654	434	854	4,551
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 (Gg)	245	715	101	913	550	393	551	3,468
Emissions (Tg CO ₂ Eq.)	0.9	2.6	0.4	3.3	2.0	1.4	2.0	12.7

^a Weighted average of other plastics produced.

Note: Totals may not sum due to independent rounding.

CO₂ 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 2001* (RMA 2002) reports that 115 million of the 218 million scrap tires generated in 2001 (approximately 53 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.¹ Table 3-59 shows consumption and carbon content of elastomers used for tires and other products in 1998, 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 CO₂ emissions, as shown in Table 3-60. Note that 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 3-59 (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 2002; 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 3-59: Elastomers Consumed (Gg), Carbon Content (%), and Carbon Equivalent (Gg) in 1998

Elastomer	Consumed (Gg)	Carbon Content	Carbon Equivalent (Gg)
Styrene butadiene rubber solid	908	91%	828
For Tires	743	91%	677
For Other Products*	165	91%	151
Polybutadiene	561	89%	499
For Tires	404	89%	359
For Other Products	157	89%	140
Ethylene Propylene	320	86%	274
For Tires	10	86%	8
For Other Products	310	86%	266
Polychloroprene	69	59%	40
For Tires	0	59%	0
For Other Products	69	59%	40
Nitrile butadiene rubber solid	87	77%	67
For Tires	1	77%	1
For Other Products	86	77%	67
Polyisoprene	78	88%	69
For Tires	65	88%	57
For Other Products	13	88%	12
Others	369	88%	324
For Tires	63	88%	56
For Other Products	306	88%	268
Total	2,392	-	2,101
For Tires	1,285	-	1,158

*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 3-60: Scrap Tire Constituents and CO₂ Emissions (Tg CO₂ Eq.) from Scrap Tire Combustion in 2001

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

Material	Weight of Material (Tg)	Fraction Oxidized	Carbon Content	Emissions (Tg CO ₂ Eq.)
Synthetic Rubber	0.3	98%	90%	0.9
Carbon Black	0.3	98%	100%	1.2
Total	0.6	-	-	2.1

- Not applicable

CO₂ from Combustion of Synthetic Rubber in Municipal Solid Waste

Similar to the methodology for scrap tires, CO₂ emissions from synthetic rubber in MSW were estimated by multiplying the amount of rubber 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). 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 3-61.² 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 2002 and 2003, waste generation values were not available, so values were held constant at the 2001 level.

Table 3-61: Rubber and Leather in Municipal Solid Waste in 2001

Product Type	Combustion (Gg)	Synthetic Rubber (%)	Carbon Content (%)	Fraction Oxidized (%)	Emissions (Tg CO ₂ Eq.)
Durables (not Tires)	506	100%	85%	98%	1.5
Non-Durables	165	-	-	-	0.2
Clothing and Footwear	110	25%	85%	98%	0.1
Other Non-Durables	55	75%	85%	98%	0.1
Containers and Packaging	4	100%	85%	98%	+
Total	675	-	-	-	1.8

+ Less than 0.05 Tg CO₂ Eq.

- Not applicable

CO₂ 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) 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 3-62). 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 2000 (see Table 3-63). The equation relating CO₂ emissions to the amount of textiles combusted is shown below. Since 2002 and 2003 values were not provided in the *Characterization* reports, generation and recovery rates for those years were held constant at the 2001 values.

$$\begin{aligned} \text{CO}_2 \text{ Emissions from the Combustion of Synthetic Fibers} &= \text{Annual Textile Combustion (Gg)} \times \\ &(\text{Percent of Total Fiber that is Synthetic}) \times (\text{Average Carbon Content of Synthetic Fiber}) \times \\ &(44\text{g CO}_2/12 \text{ g C}) \end{aligned}$$

² As a sustainably harvested biogenic material, the combustion of leather is assumed to have no net CO₂ emissions.

Table 3-62: Generation, Recovery, Discards, and Combustion of Textiles in MSW (Gg)

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	4,656	630	4,026	825
2001	4,840	705	4,135	865
2002*	4,840	705	4,135	865
2003*	4,840	705	4,135	865

* Set equal to 2001 data.

Table 3-63: Synthetic Fiber Production (Tg) and Carbon Content (%) in 2000

Fiber	Production (Tg)	Carbon Content
Polyester	1.8	63%
Nylon	1.2	64%
Olefin	1.4	86%
Acrylic	0.2	68%
Total	4.5	70%

N₂O from Municipal Solid Waste Combustion

Estimates of N₂O 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 N₂O from MSW combustion are the product of the mass of MSW combusted, an emission factor of N₂O emitted per unit mass of waste combusted, and an N₂O 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 N₂O/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 2003, so the value was assumed to remain constant at the 2002 level.

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

Bunker fuel emission estimates for the Department of Defense (DoD) were developed using data generated by the Defense Energy Support Center for aviation and naval fuels (DESC 2004). The DESC of the Defense Logistics Agency (DLA) prepared a special report based on data in the Defense Fuels Automated Management System (DFAMS). DFAMS contains data for 1995 through 2003, 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 DoD¹ and NATO² 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 3-64 displays DoD's consumption of fuels that remain at the completion of Step 1, summarized by fuel type. Table 3-64 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).

At the completion of step 3, it was apparent that the Navy MGO data provided by DESC were abnormally high compared to those data for each year from 1995 to 2002. The Navy Fuels and Logistics office confirmed, using a separate data set, that this large increase was plausible based on Operation Iraqi Freedom and the exceptionally large number of Naval fleets activated to support the war effort.

¹ DoD Directive 4140.43, Fuel Standardization, 1998; DoD Directive 4140.25, DoD Management Policy for Energy Commodities and Related Services, 1999.

² 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 3-65 and Table 3-66 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 greenhouse gas emissions.

The rows labeled "U.S. Military" and "U.S. Military Naval Fuels" within Table 3-55 and Table 3-56 in the Energy Chapter were based on the international bunker fuel totals provided in Table 3-65 and Table 3-66, below. Carbon dioxide emissions from aviation bunkers and distillate marine bunkers presented in Table 3-66 are the total of military plus civil aviation and civil marine bunker fuels, respectively. The military component of each total is based on fuels tallied in Table 3-65 and Table 3-66.

Table 3-64: 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
Aviation	4,598.45	4,562.84	3,734.49	3,610.85	3,246.23	3,099.93	2,941.91	2,685.60	2,741.40	2,635.25	2,664.45	2,900.58	2,609.75	2,614.99
Total Jet Fuels	4,598.42	4,562.81	3,734.46	3,610.83	3,246.21	3,099.91	2,941.90	2,685.59	2,741.38	2,635.24	2,664.44	2,900.55	2,609.64	2,614.92
<i>JP8</i>	<i>285.75</i>	<i>283.54</i>	<i>234.46</i>	<i>989.38</i>	<i>1,598.07</i>	<i>2,182.80</i>	<i>2,253.15</i>	<i>2,071.96</i>	<i>2,122.53</i>	<i>2,066.48</i>	<i>2,122.70</i>	<i>2,326.19</i>	<i>2,091.36</i>	<i>2,094.33</i>
<i>JP5</i>	<i>1,025.36</i>	<i>1,017.42</i>	<i>832.71</i>	<i>805.14</i>	<i>723.84</i>	<i>691.22</i>	<i>615.83</i>	<i>552.77</i>	<i>515.56</i>	<i>505.50</i>	<i>472.10</i>	<i>503.17</i>	<i>442.21</i>	<i>409.14</i>
<i>Other Jet Fuels</i>	<i>3,287.31</i>	<i>3,261.86</i>	<i>2,667.29</i>	<i>1,816.30</i>	<i>924.30</i>	<i>225.89</i>	<i>72.92</i>	<i>60.86</i>	<i>103.29</i>	<i>63.25</i>	<i>69.65</i>	<i>71.19</i>	<i>76.07</i>	<i>111.44</i>
Aviation Gasoline	0.03	0.03	0.02	0.02	0.02	0.02	0.01	+	0.02	0.01	0.01	0.03	0.11	0.08
Marine	686.80	632.61	646.18	589.37	478.59	438.91	493.34	639.85	674.22	598.86	454.36	418.45	455.85	609.15
Middle Distillate (MGO)	+	+	+	+	+	+	38.52	47.48	51.14	49.22	48.29	33.02	41.21	88.13
Naval Distillate (F76)	686.80	632.61	646.18	589.37	478.59	438.91	448.96	583.41	608.39	542.94	397.97	369.14	395.10	460.86
Intermediate Fuel Oil (IFO) ^b	+	+	+	+	+	+	5.86	8.95	14.69	6.70	8.09	16.28	19.53	60.16
Other^c	717.11	590.41	491.68	415.10	356.06	310.95	276.90	263.34	256.83	255.95	248.16	109.75	211.09	221.21
Diesel	93.04	97.88	102.96	108.31	113.94	119.86	126.09	132.64	139.53	146.78	126.63	26.65	57.66	60.79
Gasoline	624.07	492.53	388.72	306.78	242.12	191.09	150.81	119.02	93.94	74.14	74.81	24.72	27.49	26.54
Jet Fuel ^d	+	+	+	+	+	+	+	11.68	23.36	35.04	46.71	58.39	125.94	133.88
Total (Including Bunkers)	6,002.37	5,785.85	4,872.34	4,615.32	4,080.89	3,849.78	3,712.15	3,588.79	3,672.45	3,490.06	3,366.97	3,428.78	3,276.69	3,445.35

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 0.005 million gallons.

Table 3-65: 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
JP8	56.74	56.30	46.40	145.33	223.99	300.40	308.81	292.01	306.40	301.35	307.57	341.15	309.46	305.06
Navy	56.74	56.30	46.08	44.56	40.06	38.25	39.84	46.92	53.81	55.46	53.38	73.78	86.59	76.34
Air Force	0.00	0.00	0.32	100.77	183.93	262.15	268.97	245.09	252.59	245.89	254.19	267.37	222.87	228.71
JP5	370.54	367.67	300.92	290.95	261.57	249.79	219.40	194.16	184.38	175.36	160.35	169.73	158.31	146.12
Navy	365.29	362.46	296.66	286.83	257.87	246.25	216.09	191.15	181.36	170.59	155.60	163.68	152.97	141.26
Air Force	5.25	5.21	4.26	4.12	3.70	3.54	3.31	3.01	3.02	4.77	4.74	6.05	5.35	4.87
JP4	420.77	417.52	341.41	229.64	113.11	21.50	1.05	0.05	0.03	0.02	0.01	0.02	0.01	0.00
Navy	0.02	0.02	0.02	0.02	0.01	0.01	+	+	+	+	+	+	+	+
Air Force	420.75	417.50	341.39	229.62	113.10	21.49	1.05	0.05	0.03	0.02	0.01	0.02	0.01	0.00
JAA	13.70	13.60	11.13	10.76	9.68	9.24	10.27	9.42	10.84	10.79	12.46	12.61	13.68	21.66
Navy	8.45	8.39	6.86	6.64	5.97	5.70	6.58	5.88	6.63	6.32	7.95	8.02	9.84	15.49
Air Force	5.25	5.21	4.27	4.12	3.71	3.54	3.69	3.54	4.21	4.47	4.51	4.59	3.85	6.17
JA1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.03	0.13	0.62	0.19
Navy	+	+	+	+	+	+	+	+	+	0.00	0.02	0.02	0.00	0.01
Air Force	+	+	+	+	+	+	+	+	0.01	0.00	0.01	0.11	0.62	0.17
JAB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Navy	+	+	+	+	+	+	+	+	+	0.00	0.00	0.00	0.00	0.00
Air Force	+	+	+	+	+	+	+	+	+	0.00	0.00	0.00	0.00	0.00
Navy Subtotal	430.50	427.17	349.62	338.05	303.91	290.21	262.51	243.95	241.80	232.37	216.95	245.50	249.40	233.10
Air Force Subtotal	431.26	427.93	350.25	338.64	304.44	290.72	277.02	251.69	259.86	255.15	263.47	278.15	232.69	239.93
Total	861.76	855.10	699.87	676.69	608.35	580.93	539.53	495.64	501.66	487.52	480.42	523.64	482.09	473.03

+ Does not exceed 0.005 million gallons.

Note: Totals may not sum due to independent rounding.

Table 3-66: 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
Navy - MGO	+	+	+	+	+	+	30.34	35.57	31.88	39.74	23.83	22.50	27.15	63.75
Navy - F76	522.37	481.15	491.47	448.27	364.01	333.82	331.88	441.65	474.23	465.97	298.61	282.59	305.61	347.76
Navy - IFO	+	+	+	+	+	+	4.63	7.07	11.61	5.29	6.39	12.87	15.43	47.53
Total	522.37	481.15	491.47	448.27	364.01	333.82	366.85	484.29	517.72	511.00	328.84	317.95	348.19	459.04

+ Does not exceed 0.005 million gallons.

Note: Totals may not sum due to independent rounding.

Table 3-67: 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

Table 3-68: 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
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

Table 3-69: Total U.S. DoD CO₂ Emissions from Bunker Fuels (Tg CO₂ Eq.)

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

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 3-70, 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 3-70.

Table 3-70. 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				1.5%
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%	
CFC-12	HFC-134a	1992	1994	39%	None				0.5%
	HFC-134a	1992	1994	53%	None				
	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%	

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%	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%					
HCFC-22	HFC-134a	1994	1996	35%	HFC-134a	2005	2005	100%	2.5%				
	HCFC-22	1992	1993	100%	R-404A	1996	2009	75%					
R-502	HCFC-22	1990	1993	40%	R-507	1996	2009	25%	2.5%				
					R-404A	1996	2009	38%					
					R-507	1996	2009	12%					
					999	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								
										R-407C	2006	2009	25%
										R-410A	2000	2006	5%
										R-410A	2006	2009	45%
HCFC-22	HFC-134a	2000	2009	20%	None								
										R-407C	2000	2006	5%
										R-407C	2006	2009	25%
										R-410A	2000	2006	5%
	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								
CFC-12	HCFC-22	1991	1994	15%	HFC-134a	1995	2009	100%	2.5%				
					HFC-134a	1995	2009	15%					
					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								
HCFC-22	HCFC-22	1992	1993	100%	HFC-134a	1997	2000	100%	2.5%				
					HFC-134a	1995	2009	15%					
					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								
										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%					
HCFC-22	HFC-134a	1994	1996	30%	None				1.7%				
	HCFC-22	1992	1993	100%	R-404A	1996	2009	60%					
					R-507	1996	2009	15%					

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
R-502	HCFC-22	1990	1993	40%	HFC-134a	1999	2009	25%	1.7%
	R-404A	1993	1996	40%	R-404A	2000	2009	75%	
	R-507	1994	1996	10%	R-507	2000	2009	25%	
	HFC-134a	1996	1996	10%	R-507	2005	2005	100%	
					None			100%	
Transport Refrigeration									
CFC-12	HFC-134a	1993	1995	98%	None				
	HCFC-22	1993	1995	2%	HFC-134a	1995	1999	100%	
R-502	HFC-134a	1993	1995	55%	None				
	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%	
HCFC-22	HCFC-22	1992	1993	100%	HFC-134a	2000	2009	20%	2.5%
					R-407C	2000	2006	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				0.1%
	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% penetration in new equipment by 2019.

Table 3-71 presents the average equipment lifetimes for each end use assumed by the Vintaging Model.

Table 3-71. 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	15

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 3-72.

Table 3-72. Aerosol Product Transition Assumptions

Initial Market Segment	Primary Substitute	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	2004	75%	None			1.5%
	HFC-227ea	1997	2004	25%	None			
CFC-12	HFC-134a	1997	2004	75%	None			1.5%
	HFC-227ea	1997	2004	25%	None			
CFC-114	HFC-134a	1999	1999	75%	None			1.5%
	HFC-227ea	1999	1999	25%	None			
Consumer Aerosols								
NA*	HFC-152a	1990	1991	50%	None			2.0%
	HFC-134a	1995	1995	50%	HFC-152a	1997	1998	
					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 3-73.

Table 3-73. Solvent Market Transition Assumptions

Initial Market Segment	Primary Substitute	Date of Full Penetration in New Uses	Date of Full Penetration in Market	Maximum Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Uses	Maximum Penetration	Growth Rate
Electronics Cleaning									
CFC-113	Non-ODP/GWP	1992	1996	46.0%	None				2.0%
	Non-ODP/GWP	1994	1995	52.5%	None				
	HCFC-225ca/cb	1994	1995	0.2%	None				
	HFE-7100	1994	1995	0.7%	None				
	HFC-4310mee	1995	1996	0.7%	None				
MCF	Non-ODP/GWP	1996	1997	99.8%	None				2.0%
	PFC/PFPE	1996	1997	0.2%	Non-ODP/GWP	2000	2003	90%	
					Non-ODP/GWP	2005	2009	10%	
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	99.3%	None				2.0%
	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%	
CFC-113	Non-ODP/GWP	1995	1996	95.7%	None				2.0%
	HCFC-225ca/cb	1995	1996	1.0%	None				
	HFE-7100	1995	1996	3.3%	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.

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

Where:

E = Emissions. Total emissions of a specific chemical in year j for streaming fire extinguishing equipment, by weight.

- r = Percent Released. The percentage of the total chemical in operation that is released to the atmosphere.
- Q_c = Quantity of Chemical. Total amount of a specific chemical used in new fire extinguishing equipment in a given year, $j-i+1$, by weight.
- i = Counter, runs from 1 to lifetime (k).
- j = Year of emission.
- k = Lifetime. The average lifetime of the equipment.

Assumptions

Transition assumptions and growth rates for these two fire extinguishing types are presented in Table 3-74.

Table 3-74. Fire Extinguishing Market Transition Assumptions

Initial Market Segment	Primary Substitute	Date of Full Penetration Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Secondary Substitute	Date of Full Penetration Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	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.
- Q_c = 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 $i=1 \rightarrow k$). 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 3-75. The emission profiles of the foam types estimating in the Vintaging Model are shown in Table 3-76.

Table 3-75. Foam Blowing Market Transition Assumptions

Initial Market Segment	Primary Substitute	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%

Initial Market Segment	Primary Substitute	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
				HFC-152a	2009	2010	10%	
				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%
					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%
					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%
					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%
					Non-ODP/GWP	2001	2003	45%
					HCFC-22	2003	2003	10%
Polyurethane Spray Foam								
CFC-11	HCFC-141b	1989	1996	95%	HFC-245fa	2004	2005	30%
					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 3-76. 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	15	27.675	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 CO₂ Eq.). The conversion of metric tons of chemical to Tg CO₂ Eq. is accomplished through a linear scaling of tonnage by the global warming potential (GWP) of each chemical.

Throughout its development, the Vintaging Model has undergone annual modifications. As new or more accurate information becomes available, the model is adjusted in such a way that both past and future emission estimates are often altered.

3.9. Methodology for Estimating CH₄ Emissions from Enteric Fermentation

Methane emissions from enteric fermentation were estimated for five livestock categories: cattle, horses, sheep, swine, and goats. Emissions from cattle represent the majority of U.S. emissions; 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 3-77.

Table 3-77: 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 bulls¹) 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 (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 2002. 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 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, 15, 24, and 36 month-old animals. Live slaughter weights were derived from dressed slaughter weight data for each year (USDA 2004c, 2003c, 2002c, 2001c, 2000c, 1999a, 1995a). Live slaughter weight was estimated as dressed weight divided by 0.63.

¹ Only end-of-year census population statistics and a national emission factors are used to estimate methane emissions from the bull population.

- *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 2003 are shown in Table 3-78. Table 3-79 provides the target weights used to track average weights of cattle by animal type. Table 3-80 provides a summary of the reported feedlot placement statistics for 2003. Data on feedlot placements were available for 1996 through 2003. 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 3-88 of the Manure Management Annex (Annex 3-10). 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 (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 States² 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 US. 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 3-81, 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.³ 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 3-82. 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 3-83 shows the regional DE, the Y_m , and percent of total U.S. cattle population in each region based on 2003 data.

Step 3: Estimate Methane 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)

² 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 the research conducted to characterize the diets of U.S. cattle and to assess the Y_m values associated with different animal performance and feed characteristics in the United States.

³ 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.

- Net Energy for Activity (C_a , MJ/day)⁴
- Standard Reference Weight⁵ (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 emissions 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:

$$\text{DayEmit} = [GE \times Y_m] / [55.65 \text{ MJ/kg CH}_4]$$

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)

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

⁴ 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.

⁵ Standard Reference Weight is used in the model to account for breed potential.

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 CH₄/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 emissions estimate for the entire year. The estimates for each of the 10 subcategories of cattle are listed in Table 3-84. 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 3-88 of the Manure Management Annex (Annex 3-10) 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 2004). 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 3-85 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 3-86 (Tg CO₂ Eq.) and Table 3-87 (Gg).

Table 3-78: Dairy Lactation by Region (lbs· year/cow)*

Year	California	West	Northern Great			Midwest	Southeast
			Plains	Southcentral	Northeast		
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

Source: USDA (2004d, 2003d, 2002d, 2001d, 2000d, 1999a, 1995a).

* Beef lactation data were developed using the methodology described in the text.

Table 3-79: 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 3-80: Feedlot Placements in the United States for 2003 (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	424	260	270	296	408	372	426	602	698	1023	680	503	5,962
600 - 700 lbs	575	371	389	324	367	358	414	529	545	796	578	529	5,775
700 - 800 lbs	692	593	742	613	749	480	593	659	610	508	379	448	7,066
> 800 lbs	398	426	631	637	783	462	564	594	621	454	289	268	6,127
Total	2,089	1,650	2,032	1,870	2,307	1,672	1,997	2,384	2,474	2,781	1,926	1,748	24,930

Source: USDA (2003f, 2002f, 2001f, 2000f, 1999a, 1995a).

Note: Totals may not sum due to independent rounding.

Table 3-81: DE Values and Representative Regional Diets (Percent of Diet for each Region) for the Supplemental Diet of Grazing Beef Cattle

Feed	Source of TDN (NRC 2000)	Unweighted TDN or DE	Northern Great Plains						
			California	West	Southcentral	Northeast	Midwest	Southeast	
Alfalfa Hay	Table 11-1, feed #4	59.6%	65%	30%	30%	29%	12%	30%	
Barley	Table 11-1, feed #12	86.3%	10%	15%					
Bermuda	Table 11-1, feed #17	48.5%							35%
Bermuda Hay	Table 11-1, feed #17	48.5%				40%			
Corn	Table 11-1, feed #38	88.1%	10%	10%	25%	11%	13%	13%	
Corn Silage	Table 11-1, feed #39	71.2%			25%		20%	20%	
Cotton Seed Meal	Table 11-1, feed #42	74.4%				7%			
Grass Hay	Table 1a, feed #129, 147, 148								
Orchard	Table 11-1, feed #61	53.7%		40%				30%	
Soybean Meal		53.5%							40%
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			65.2%	65.1%	62.4%	65.0%	74.3%	58.8%	69.3%

Source of representative regional diets: Donovan (1999).

Table 3-82: Percent of Each Diet that is Supplemental, and the Resulting DE Values for Each Region

Region	Percent		Calculated Weighted
	Supplement	Percent Forage	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 3-83: Regional Digestible Energy (DE), Methane Conversion Rates (Y_m), and Population Percentages for Cattle in 2003

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%	28%	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.	19%	13%	4%	4%	19%	35%	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%	38%	25%	2%	19%	5%
Heifer Stockers	DE	65%	59%	66%	64%	65%	65%	64%
	Y_m	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
	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%	47%	23%	1%	18%	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%	47%	23%	1%	18%	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.	18%	15%	5%	5%	18%	32%	8%
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 3-84: CH₄ Emissions from Cattle (Gg)

Cattle Type	1990	1997	1998	1999	2000	2001	2002	2003
Dairy	1,375	1,255	1,251	1,265	1,283	1,282	1,290	1,300
Cows	1,142	1,028	1,026	1,037	1,058	1,054	1,062	1,071
Replacements 7-11 months	49	48	48	48	48	48	49	48
Replacements 12-23 months	184	179	177	180	177	179	180	182
Beef	3,961	4,124	4,047	4,045	3,973	3,923	3,919	3,930
Cows	2,428	2,574	2,531	2,520	2,507	2,492	2,472	2,461
Replacements 7-11 months	52	56	54	53	53	54	54	53
Replacements 12-23 months	190	216	206	198	198	200	200	201
Steer Stockers	431	430	418	400	362	348	352	358
Heifer Stockers	232	241	236	229	207	202	204	208
Feedlot Cattle	412	374	378	420	426	408	421	430
Bulls	218	233	223	224	220	219	217	217
Total	5,337	5,379	5,297	5,310	5,256	5,205	5,209	5,230

Note: Totals may not sum due to independent rounding.

Table 3-85: Emission Factors for Other Livestock (kg CH₄/head/year)

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

Source: IPCC (2000).

Table 3-86: CH₄ Emissions from Enteric Fermentation (Tg CO₂ Eq)

Livestock Type	1990	1997	1998	1999	2000	2001	2002	2003
Beef Cattle	83.2	86.6	85.0	84.9	83.4	82.4	82.3	82.5
Dairy Cattle	28.9	26.4	26.3	26.6	27.0	26.9	27.1	27.3
Horses	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Sheep	1.9	1.3	1.3	1.2	1.2	1.2	1.1	1.1
Swine	1.7	1.8	2.0	1.9	1.9	1.9	1.9	1.9
Goats	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	117.9	118.3	116.7	116.8	115.6	114.5	114.6	115.0

Table 3-87: CH₄ Emissions from Enteric Fermentation (Gg)

Livestock Type	1990	1997	1998	1999	2000	2001	2002	2003
Beef Cattle	3,961	4,124	4,047	4,045	3,973	3,923	3,919	3,930
Dairy Cattle	1,375	1,255	1,251	1,265	1,283	1,282	1,290	1,300
Horses	91	93	94	93	94	95	95	95
Sheep	91	64	63	58	56	56	53	50
Swine	81	88	93	90	88	88	90	90
Goats	13	10	10	10	10	10	10	10
Total	5,612	5,634	5,557	5,561	5,505	5,454	5,458	5,475

3.10. Methodology for Estimating CH₄ and N₂O Emissions from Manure Management

This annex presents a discussion of the methodology used to calculate methane and nitrous oxide 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 methane and nitrous oxide 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 emissions estimates for Agricultural Soil Management (see Annex 3.11).

Step 1: Livestock Population Characterization Data

Annual animal population data for 1990 through 2003 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-g, 2001a-f, 2002 a-f, 2003 a-f, 2004 a-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 2004). Goat population data for 1992 and 1997 were obtained from the Census of Agriculture (USDA 1999d). Information regarding poultry turnover (i.e., slaughter) rate was obtained from state Natural Resource Conservation Service personnel (Lange 2000).

A summary of the livestock population characterization data used to calculate methane and nitrous oxide emissions is presented in Table 3-88.

Dairy Cattle: The total annual dairy cow and heifer state population data for 1990 through 2003 are provided in various USDA National Agricultural Statistics Service reports (1995a, 1999a, 2000a-b, 2001a-b, 2002a-b, 2003a-b, 2004 a-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.usda.gov/nass/>>), Cattle and Calves. The specific data used to estimate dairy cattle populations are “Cows That Calved – Milk” and “Heifers 500+ Lbs – Milk Repl.”

Beef Cattle: The total annual beef cattle population data for each state for 1990 through 2003 are provided in various USDA National Agricultural Statistics Service reports (1995a, 1999a, 2000a-b, 2001a-b, 2002a-b, 2003a-b, 2004 a-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.usda.gov/nass/>>), Cattle and Calves. The specific data used to estimate beef cattle populations are: “Cows That Calved—Beef,” “Heifers 500+ Lbs—Beef Repl,” “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 2001 are provided in various USDA National Agricultural Statistics Service reports (USDA 1994a, 1998a, 2000c, 2001c, 2002c, 2003c, 2004c). 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.usda.gov/nass/>>), Hogs and Pigs.

Sheep: The total annual sheep population data for each state for 1990 through 2003 were obtained from USDA National Agricultural Statistics Service (USDA 1994b, 1999c, 2000f, 2001f, 2002f, 2003f, 2004f). Population data for lamb and sheep on feed are not available after 1993. The number of lamb and sheep on feed for 1994 through 2003 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 and 1997 (USDA 1999d). The data for 1992 were used for 1990 through 1992 and the data for 1997 were used for 1997 through 2003. Data for 1993 through 1996 were extrapolated using the 1992 and 1997 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, 2000d-e, 2000g, 2001d-e, 2002d-e, 2003d-e, 2004d-e). The annual population data for broilers 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://apps.fao.org/>> (FAO 2004). State horse population data were estimated using state population distributions from the 1992 and 1997 Census of Agriculture and the FAO national population data.

Step 2: Waste Characteristics Data

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

- Volatile solids excretion rate (VS)
- Maximum methane producing capacity (B_0) for U.S. animal waste
- Nitrogen excretion rate (N_{ex})
- Typical animal mass (TAM)

Table 3-89 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. N_{ex} rates were collected from the sources indicated in Table 3-89 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:

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

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, Pederson, and Pape, 2004).

Table 3-90 presents the state-specific volatile solids production rates used for 2003.

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 2001a)
- Contacts with the national USDA office to estimate the percent of beef steers and heifers in feedlots (Milton 2000)
- Survey data collected by USDA (USDA 1998d, 2000h) and re-aggregated by farm size and geographic location, used for small operations
- Survey data collected by the United Egg Producers (UEP 1999) and USDA (2000i) 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 3-91 through Table 3-96 summarize 2003 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 (WMS) data were developed using information from EPA's Office of Water's engineering cost analyses conducted to support the development of effluent limitations guidelines for Concentrated Animal Feeding Operations (EPA 2001a). 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 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

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 WMS data for dairy cows was 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 1999e). Due to a lack of additional data for other years, 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, 1999, 2000, 2001, 2002, and 2003. 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 2001a). Manure management system data for small (fewer than 200 head) dairies were obtained from USDA (2000h). 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 1999e) 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 2003, which were obtained from the National Agricultural Statistics Service (USDA 1995a, 1999a, 2000a-b, 2001a-b, 2002a-b, 2003a-b, 2004a-b).

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 2001a), 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 1999e) 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.

Due to lack of additional data, 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 2003. 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 2003 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: 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 2000i). 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 2003 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* (EPA 1992). It was assumed that 1 percent of poultry waste are deposited in pastures, range, 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. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (IPCC 2000) published default methane conversion factors for dry systems according to climate classification (cool, temperate, or warm). The IPCC default MCFs for the temperate climate classification were used for all animal waste managed in dry systems as follows:

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%

Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000) published default methane 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:

$T_1 = 303.16\text{K}$

$T_2 =$ 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 systems (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), and the county population data were calculated from the state-level NASS data and the distribution of county-to-state population calculated from the 1992 and 1997 Census data (USDA 1999e). County population distribution data for 1990 and 1991 were assumed to be the same as 1992; county population distribution data for 1998 through 2001 were assumed to be the same as 1997; and county population distribution data for 1993 through 1996 were extrapolated based on 1992 and 1997 data.

Annual MCFs for liquid systems are calculated as follows for each animal type, state, and year of the inventory:

- 1) 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.
- 2) 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.
- 3) 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).
- 4) 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.
- 5) The amount of volatile solids consumed during the month is equal to the amount available for conversion multiplied by the “f” factor.

- 6) 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.
- 7) 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).
- 8) The annual MCF is then calculated as:

$$MCF_{(annual)} = CH_4 \text{ generated}_{(annual)} / (VS \text{ produced}_{(annual)} \times B_o)$$

Where:

$MCF_{(annual)}$	=	Methane conversion factor
$VS \text{ produced}_{(annual)}$	=	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 methane. The MCFs presented in Table 3-97 by state and waste management system represent the average MCF for 2003 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 methane and nitrous oxide 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:

$EF_{\text{animal, state}}$	=	Weighted emission factor for that animal group and state
EF_{system}	=	Emission factor for that system (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)

For each state, the MCFs attributed to each animal group were weight-averaged according to the waste management system distribution in that state for that animal group. A summary of the weighted MCFs used to calculate beef feedlot, dairy cow and heifer, swine, and poultry emissions for 2003 are presented in Table 3-98. For certain animal groups (beef cattle not on feed, horses, sheep, and goats), the emission factors do not vary for the management systems used. In these cases, a weighted emission factor was not necessary.

Step 6: Methane and Nitrous Oxide Emission Calculations

Methane emissions were calculated for each animal group as follows:

$$\text{Methane}_{\text{animal group}} = \sum_{\text{state}} (\text{Population} \times \text{VS} \times B_o \times \text{MCF}_{\text{animal, state}} \times 0.662)$$

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:

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

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 ₂ O-N/kg N excreted (see Step 5)
44/28	=	conversion factor of N ₂ O-N to N ₂ O

Emission estimates are summarized in Table 3-99 and Table 3-100.

Table 3-88: Livestock Population (1,000 Head)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Dairy Cattle	14,143	13,980	13,830	13,767	13,566	13,502	13,305	13,138	12,992	13,026	13,070	12,970	13,011	12,978
Dairy Cows	10,007	9,883	9,714	9,679	9,504	9,491	9,410	9,309	9,200	9,142	9,220	9,141	9,131	9,121
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	3,880	3,857
Swine	53,941	56,478	58,532	58,016	59,951	58,899	56,220	58,728	61,991	60,245	58,892	58,970	60,015	59,762
Market <60 lbs.	18,359	19,212	19,851	19,434	20,157	19,656	18,851	19,886	20,691	19,928	19,582	19,657	19,841	19,901
Market 60-119 lbs.	11,734	12,374	12,839	12,656	13,017	12,836	12,157	12,754	13,552	13,256	12,933	12,939	13,292	13,149
Market 120-179 lbs.	9,440	9,840	10,253	10,334	10,671	10,545	10,110	10,480	11,235	11,043	10,753	10,709	11,018	11,035
Market >180 lbs.	7,510	7,822	8,333	8,435	8,824	8,937	8,463	8,768	9,672	9,645	9,390	9,477	9,733	9,702
Breeding	6,899	7,231	7,255	7,157	7,282	6,926	6,639	6,840	6,841	6,374	6,233	6,188	6,131	5,977
Beef Cattle	86,087	87,267	88,548	90,321	92,571	94,391	94,269	92,290	90,730	90,032	89,215	88,622	87,930	87,040
Feedlot Steers	7,338	7,920	7,581	7,984	7,797	7,763	7,380	7,644	7,845	7,782	8,280	8,565	8,356	7,944
Feedlot Heifers	3,621	4,035	3,626	3,971	3,965	4,047	3,999	4,396	4,459	4,578	4,872	5,035	4,824	4,571
NOF Bulls ²	2,180	2,198	2,220	2,239	2,306	2,392	2,392	2,325	2,235	2,241	2,196	2,187	2,172	2,174
NOF Calves ²	23,909	23,853	24,118	24,209	24,586	25,170	25,042	24,363	24,001	23,896	23,508	22,952	22,581	22,273
NOF Heifers ²	8,872	8,938	9,520	9,850	10,469	10,680	10,869	10,481	9,998	9,725	9,353	9,225	9,235	9,336
NOF Steers ²	7,490	7,364	8,031	7,935	8,346	8,693	9,077	8,452	8,050	7,864	7,248	7,009	7,328	7,451
NOF Cows ²	32,677	32,960	33,453	34,132	35,101	35,645	35,509	34,629	34,143	33,948	33,760	33,649	33,434	33,292
Sheep	11,358	11,174	10,797	10,201	9,836	9,899	8,465	8,024	7,817	7,215	7,032	6,965	6,685	6,300
Sheep NOF	10,178	10,064	9,613	9,009	8,824	8,083	7,595	7,172	6,985	6,430	6,260	6,200	5,963	5,585
Sheep on Feed	1,180	1,110	1,183	1,192	1,012	906	870	851	831	785	772	765	722	715
Goats	2,516	2,516	2,516	2,410	2,305	2,200	2,095	1,990	1,990	1,990	1,990	1,990	1,990	1,990
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	1,964,152	2,008,197	2,031,163	2,056,603	2,090,023	2,076,887
Hens >1 yr.	119,551	117,178	121,103	131,688	135,094	133,841	138,048	140,966	150,781	152,024	153,439	153,817	153,108	169,263
Pullets ¹	227,083	239,559	243,267	240,712	243,286	246,599	247,446	261,515	265,945	275,285	275,313	282,156	280,475	271,047
Chickens	6,545	6,857	7,113	7,240	7,369	7,637	7,243	7,549	7,682	9,659	8,088	8,126	8,339	8,438
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	1,442,582	1,481,165	1,506,127	1,525,415	1,562,015	1,544,155
Turkeys	117,685	115,504	114,426	110,635	107,469	106,960	108,112	105,088	97,162	90,064	88,195	87,089	86,087	83,984
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

Note: Totals may not sum due to independent rounding.

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

²NOF = Not on Feed

Table 3-89: Waste Characteristics Data

Animal Group	Average		Total Kjeldahl Nitrogen, N _{ex} (kg/day per 1,000 kg mass) Source		Maximum Methane Generation Potential, B ₀ (m ³ CH ₄ /kg VS added) Source		Volatile Solids, VS (kg/day per 1,000 kg mass) Source	
	TAM (kg)	Source						
Dairy Cows	604	Saffley 2000	0.44	USDA 1996a	0.24	Morris 1976	Table 3-90 Lieberman, Pederson, and Pape, 2004	
Dairy Heifers	476	Saffley 2000	0.31	USDA 1996a	0.17	Bryant et. al. 1976	Table 3-90 Lieberman, Pederson, and Pape, 2004	

Feedlot Steers	420 USDA 1996a	0.30 USDA 1996a	0.33 Hashimoto 1981	Table 3-90 Lieberman, Pederson, and Pape, 2004
Feedlot Heifers	420 USDA 1996a	0.30 USDA 1996a	0.33 Hashimoto 1981	Table 3-90 Lieberman, Pederson, and Pape, 2004
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 3-90 Lieberman, Pederson, and Pape, 2004
NOF Steers	318 Safley 2000	0.31 USDA 1996a	0.17 Hashimoto 1981	Table 3-90 Lieberman, Pederson, and Pape, 2004
NOF Cows	533 NRC 2000	0.33 USDA 1996a	0.17 Hashimoto 1981	Table 3-90 Lieberman, Pederson, and Pape, 2004
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 3-90: Estimated Volatile Solids Production Rate by State for 2003

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	8.50	6.82	6.74	7.22	7.72	4.06	3.89
Alaska	10.87	6.82	8.71	9.50	10.21	4.03	3.87
Arizona	10.87	6.82	8.71	9.53	10.21	4.03	3.87
Arkansas	8.58	7.57	6.72	7.20	7.70	4.03	3.87
California	9.38	6.82	6.57	7.06	7.51	3.96	3.80
Colorado	8.68	6.82	6.19	6.67	7.04	4.03	3.87
Connecticut	8.44	6.14	6.62	7.13	7.58	4.01	3.84
Delaware	8.44	6.14	6.62	7.14	7.58	4.01	3.84
Florida	8.50	6.82	6.74	7.20	7.72	4.06	3.89
Georgia	8.50	6.82	6.74	7.22	7.72	4.06	3.89
Hawaii	10.87	6.82	8.71	9.52	10.21	4.03	3.87
Idaho	10.87	6.82	8.71	9.59	10.21	4.03	3.87
Illinois	8.54	6.82	6.63	7.15	7.58	3.96	3.80
Indiana	8.54	6.82	6.63	7.13	7.58	3.96	3.80
Iowa	8.54	6.82	6.63	7.17	7.58	3.96	3.80
Kansas	8.68	6.82	6.19	6.67	7.04	4.03	3.86
Kentucky	8.5	6.82	6.74	7.24	7.72	4.06	3.89
Louisiana	8.58	7.57	6.72	7.08	7.70	4.03	3.87
Maine	8.44	6.14	6.62	7.18	7.58	4.01	3.84
Maryland	8.44	6.14	6.62	7.11	7.58	4.01	3.84
Massachusetts	8.44	6.14	6.62	7.12	7.58	4.01	3.84
Michigan	8.54	6.82	6.63	7.13	7.58	3.96	3.80
Minnesota	8.54	6.82	6.63	7.14	7.58	3.96	3.80
Mississippi	8.50	6.82	6.74	7.21	7.72	4.06	3.89
Missouri	8.54	6.82	6.63	7.12	7.58	3.96	3.80
Montana	8.68	6.82	6.19	6.60	7.04	4.03	3.86
Nebraska	8.68	6.82	6.19	6.67	7.04	4.03	3.86
Nevada	10.87	6.82	8.71	9.54	10.21	4.03	3.87
New Hampshire	8.44	6.14	6.62	7.08	7.58	4.01	3.84
New Jersey	8.44	6.14	6.62	7.11	7.58	4.01	3.84
New Mexico	10.87	6.82	8.71	9.56	10.21	4.03	3.87
New York	8.44	6.14	6.62	7.14	7.58	4.01	3.84
North Carolina	8.50	6.82	6.74	7.21	7.72	4.06	3.89
North Dakota	8.68	6.82	6.19	6.64	7.04	4.03	3.86
Ohio	8.54	6.82	6.63	7.12	7.58	3.96	3.80
Oklahoma	8.58	7.57	6.72	7.24	7.70	4.03	3.87
Oregon	10.87	6.82	8.71	9.55	10.21	4.03	3.87
Pennsylvania	8.44	6.14	6.62	7.12	7.58	4.01	3.84
Rhode Island	8.44	6.14	6.62	7.08	7.58	4.01	3.84
South Carolina	8.50	6.82	6.74	7.22	7.72	4.06	3.89
South Dakota	8.68	6.82	6.19	6.64	7.04	4.03	3.86
Tennessee	8.50	6.82	6.74	7.22	7.72	4.06	3.89
Texas	8.58	7.57	6.72	7.25	7.70	4.03	3.87
Utah	10.87	6.82	8.71	9.55	10.21	4.03	3.87
Vermont	8.44	6.14	6.62	7.12	7.58	4.01	3.84
Virginia	8.50	6.82	6.74	7.23	7.72	4.06	3.89
Washington	10.87	6.82	8.71	9.59	10.21	4.03	3.87
West Virginia	8.44	6.14	6.62	7.10	7.58	4.01	3.84
Wisconsin	8.54	6.82	6.63	7.12	7.58	3.96	3.80
Wyoming	8.68	6.82	6.19	6.63	7.04	4.03	3.86

Source: Lieberman, Pederson, and Pape, 2004.

Table 3-91: 2003 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

State	Pasture	Daily Spread	Solid Storage	Dry Lot ^a	Liquid/ Slurry ^a	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
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 3-92: 2003 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

State	Pasture	Solid			Anaerobic			Poultry with Bedding	Poultry without Bedding
		Daily Spread	Storage	Dry Lot	Liquid/ Slurry	Lagoon	Deep Pit		
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 3-93: 2003 Manure Distribution Among Waste Management Systems at Dairy Heifer Facilities (Percent)

State	Pasture	Daily		Solid		Anaerobic		Poultry with Bedding	Poultry without Bedding
		Spread	Storage	Dry Lot ¹	Liquid/ Slurry ¹	Lagoon	Deep Pit		
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

State	Pasture	Daily Spread	Solid Storage	Dry Lot ¹	Liquid/ Slurry ¹	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
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 3-94: 2003 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

State	Pasture	Daily Spread	Solid Storage	Dry Lot	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
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 3-95: 2003 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

State	Pasture	Daily Spread	Solid Storage	Dry Lot	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
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 3-96: 2003 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	0	99
Alaska	1	0	0	0	0	0	0	0	99
Arizona	1	0	0	0	0	0	0	0	99
Arkansas	1	0	0	0	0	0	0	0	99
California	1	0	0	0	0	0	0	0	99
Colorado	1	0	0	0	0	0	0	0	99
Connecticut	1	0	0	0	0	0	0	0	99
Delaware	1	0	0	0	0	0	0	0	99
Florida	1	0	0	0	0	0	0	0	99
Georgia	1	0	0	0	0	0	0	0	99
Hawaii	1	0	0	0	0	0	0	0	99
Idaho	1	0	0	0	0	0	0	0	99
Illinois	1	0	0	0	0	0	0	0	99
Indiana	1	0	0	0	0	0	0	0	99
Iowa	1	0	0	0	0	0	0	0	99
Kansas	1	0	0	0	0	0	0	0	99
Kentucky	1	0	0	0	0	0	0	0	99
Louisiana	1	0	0	0	0	0	0	0	99

State	Pasture	Daily Spread	Solid Storage	Dry Lot	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
Maine	1	0	0	0	0	0	0	0	99
Maryland	1	0	0	0	0	0	0	0	99
Massachusetts	1	0	0	0	0	0	0	0	99
Michigan	1	0	0	0	0	0	0	0	99
Minnesota	1	0	0	0	0	0	0	0	99
Mississippi	1	0	0	0	0	0	0	0	99
Missouri	1	0	0	0	0	0	0	0	99
Montana	1	0	0	0	0	0	0	0	99
Nebraska	1	0	0	0	0	0	0	0	99
Nevada	1	0	0	0	0	0	0	0	99
New Hampshire	1	0	0	0	0	0	0	0	99
New Jersey	1	0	0	0	0	0	0	0	99
New Mexico	1	0	0	0	0	0	0	0	99
New York	1	0	0	0	0	0	0	0	99
North Carolina	1	0	0	0	0	0	0	0	99
North Dakota	1	0	0	0	0	0	0	0	99
Ohio	1	0	0	0	0	0	0	0	99
Oklahoma	1	0	0	0	0	0	0	0	99
Oregon	1	0	0	0	0	0	0	0	99
Pennsylvania	1	0	0	0	0	0	0	0	99
Rhode Island	1	0	0	0	0	0	0	0	99
South Carolina	1	0	0	0	0	0	0	0	99
South Dakota	1	0	0	0	0	0	0	0	99
Tennessee	1	0	0	0	0	0	0	0	99
Texas	1	0	0	0	0	0	0	0	99
Utah	1	0	0	0	0	0	0	0	99
Vermont	1	0	0	0	0	0	0	0	99
Virginia	1	0	0	0	0	0	0	0	99
Washington	1	0	0	0	0	0	0	0	99
West Virginia	1	0	0	0	0	0	0	0	99
Wisconsin	1	0	0	0	0	0	0	0	99
Wyoming	1	0	0	0	0	0	0	0	99

Table 3-97: Methane Conversion Factors By State for Liquid Systems¹ for 2003 (percent)

State	Liquid/Slurry and Deep Pit	Anaerobic Lagoon
Alabama	38.5	75.8
Alaska	13.8	48.3
Arizona	44.8	79.3
Arkansas	36.1	65.0
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

¹ As defined by IPCC (IPCC 2000). MCFs represent weighted average of multiple animal types.

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	74.4
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

Table 3-98: Weighted Methane Conversion Factors for 2003^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	10.2	1.9	48.5	48.5	32.6	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	1.5	61.6	1.7	53.3	53.3	48.2	1.5	1.5
Arkansas	2.0	2.0	7.4	1.9	54.0	16.4	1.5	1.5	1.5
California	2.0	2.0	51.9	1.9	50.8	50.5	10.6	1.5	1.5
Colorado	1.6	1.6	43.4	1.6	27.7	27.7	40.2	1.5	1.5
Connecticut	1.7	1.7	10.6	1.7	13.9	13.7	4.9	1.5	1.5
Delaware	1.8	1.8	9.6	1.7	32.5	32.5	5.1	1.5	1.5
Florida	2.2	2.2	42.2	2.0	21.7	21.8	33.4	1.5	1.5
Georgia	2.0	2.0	14.4	1.9	49.1	48.8	32.2	1.5	1.5
Hawaii	2.3	2.3	54.7	2.1	39.6	39.6	20.4	1.5	1.5
Idaho	1.6	1.6	45.9	1.6	21.1	21.0	41.0	1.5	1.5
Illinois	1.7	1.7	11.9	1.6	31.6	31.6	2.9	1.5	1.5
Indiana	1.7	1.7	9.8	1.6	30.5	30.6	1.5	1.5	1.5
Iowa	1.7	1.6	10.0	1.6	40.8	40.9	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	44.1	44.0	5.1	1.5	1.5
Louisiana	2.1	2.1	11.1	2.0	20.5	20.5	47.1	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	1.8	9.0	1.7	29.2	29.2	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	27.5	27.4	2.8	1.5	1.5
Minnesota	1.6	1.6	9.1	1.6	29.3	29.3	1.5	1.5	1.5
Mississippi	2.0	2.0	9.3	1.9	55.5	55.6	46.2	1.5	1.5
Missouri	1.7	1.7	10.8	1.7	33.8	33.8	1.5	1.5	1.5
Montana	1.6	1.6	26.3	1.6	25.5	25.5	40.0	1.5	1.5

Nebraska	1.7	1.7	10.5	1.6	31.3	31.2	2.9	1.5	1.5
Nevada	1.6	1.6	51.6	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	1.8	8.2	1.7	18.3	18.4	5.0	1.5	1.5
New Mexico	1.6	1.6	52.9	1.6	1.5	1.5	46.2	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	58.0	57.9	32.0	1.5	1.5
North Dakota	1.6	1.6	6.8	1.6	25.4	25.5	2.8	1.5	1.5
Ohio	1.7	1.6	10.0	1.6	28.6	28.7	1.5	1.5	1.5
Oklahoma	1.6	1.6	35.3	1.6	56.3	56.8	46.5	1.5	1.5
Oregon	1.8	1.8	27.1	1.7	11.4	11.4	17.4	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	18.8	18.8	4.9	1.5	1.5
South Carolina	2.0	2.0	10.4	1.9	50.8	50.6	46.2	1.5	1.5
South Dakota	1.7	1.6	9.3	1.6	29.2	29.3	2.8	1.5	1.5
Tennessee	1.8	1.8	5.5	1.8	41.9	41.7	5.1	1.5	1.5
Texas	1.7	1.7	50.8	1.6	52.6	52.7	10.6	1.5	1.5
Utah	1.6	1.6	38.3	1.6	30.6	31.4	43.9	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	49.0	49.0	5.0	1.5	1.5
Washington	1.8	1.8	33.7	1.8	21.9	21.6	9.2	1.5	1.5
West Virginia	1.8	1.7	6.9	1.7	20.1	20.1	4.9	1.5	1.5
Wisconsin	1.6	1.6	9.9	1.6	26.6	26.5	2.8	1.5	1.5
Wyoming	1.6	1.6	23.8	1.6	27.0	26.9	39.8	1.5	1.5

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

Table 3-99: CH₄ Emissions from Livestock Manure Management (Gg)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Dairy Cattle	545	585	574	566	623	639	611	639	662	700	692	715	722	748
Dairy Cows	536	576	565	557	614	630	603	631	653	691	684	706	713	740
Dairy Heifer	9	9	9	9	9	9	9	9	8	9	9	9	9	9
Swine	622	674	637	678	739	761	727	780	874	837	812	826	843	808
Market Swine	483	524	500	533	584	607	581	625	715	683	665	677	695	670
Market <60 lbs.	102	110	103	108	118	121	116	125	139	131	128	131	133	129
Market 60-119 lbs.	101	111	104	110	119	123	117	127	143	136	132	134	138	133
Market 120-179 lbs.	136	147	140	151	164	170	164	175	200	191	185	187	193	186
Market >180 lbs.	144	156	152	164	181	193	184	198	233	225	219	225	231	222
Breeding Swine	139	151	138	145	155	154	147	155	160	155	148	150	149	139
Beef Cattle	153	152	153	153	155	155	155	152	149	150	149	148	147	146
Feedlot Steers	24	21	21	19	18	16	16	16	16	18	19	19	18	17
Feedlot Heifers	12	13	11	11	10	10	9	10	10	10	11	11	11	10
NOF Bulls	6	6	6	6	6	7	7	6	6	6	6	6	6	6
NOF Calves	11	11	11	11	11	12	12	11	11	11	11	11	11	10
NOF Heifers	16	17	18	18	19	20	20	19	18	18	17	17	17	17
NOF Steers	11	11	12	11	12	12	13	12	12	12	11	10	11	11
NOF Cows	73	73	74	76	78	79	79	77	76	75	75	74	74	74
Sheep	9	9	8	8	8	7	7	6	6	6	5	5	5	5
Goats	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poultry	128	129	125	129	129	127	125	127	130	125	125	129	126	127
Hens >1 yr.	33	31	33	34	34	33	32	31	33	31	31	31	30	31
Total Pullets	63	65	59	60	60	58	56	58	60	57	57	60	59	58
Chickens	4	4	4	4	4	4	3	3	4	3	3	3	4	4
Broilers	19	20	21	21	22	23	24	25	25	26	27	27	28	27
Turkeys	10	10	10	10	9	9	9	9	8	8	8	8	7	7
Horses	27	27	28	28	28	28	28	28	28	28	28	29	29	29

Table 3-100: N₂O Emissions from Livestock Manure Management (Gg)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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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
Dairy Cows	9.4	9.3	9.0	8.9	8.7	8.7	8.6	8.4	8.2	8.2	8.2	8.1	7.9	7.9
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
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
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
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
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
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
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
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
Beef Cattle	15.8	17.3	16.2	17.3	17.0	17.1	16.5	17.4	17.8	17.9	19.0	19.7	19.1	18.1
Feedlot Steers	10.6	11.5	11.0	11.5	11.3	11.2	10.7	11.1	11.3	11.3	12.0	12.4	12.1	11.5
Feedlot Heifers	5.2	5.8	5.2	5.7	5.7	5.9	5.8	6.4	6.4	6.6	7.0	7.3	7.0	6.6
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
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
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
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
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
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
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
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
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

+ Emission estimate is less than 0.1 Gg

3.11. Methodology for Estimating N₂O Emissions from Agricultural Soil Management.

Nitrous oxide (N₂O) emissions from agricultural soils result from activities that add nitrogen (N) to or transfer N within soils, and thereby enhance natural emissions of N₂O. Nitrous oxide emissions were calculated from three categories: (1) direct and indirect emissions from managed mineral agricultural soils, (2) direct emissions from histosols, and (3) direct N₂O emissions from pasture, range, and paddock (PRP) livestock manure;

A hybrid approach was used to estimate direct and indirect emissions from mineral agricultural soils. The process-based biogeochemical model DAYCENT was applied to the estimation of N₂O emissions resulting from lands producing major crop types, while the IPCC methodology was applied to non-major crop types. Histosols were estimated using the IPCC default method and direct N₂O emissions from PRP manure were obtained by using a combination of DAYCENT generated factors for manure deposited on pasturelands and applying IPCC defaults to manure deposited on paddocks and rangelands. Indirect volatilization and leaching/runoff were accounted for differently under each method.

DAYCENT (Del Grosso et al. 2001, Parton et al. 1998) was used to simulate fluxes of N₂O between mineral agricultural soils and the atmosphere for lands where major crop types (e.g., corn, soybean, wheat, alfalfa hay, other hay, silage, cotton and sorghum) are grown. DAYCENT simulates biogeochemical N fluxes between the atmosphere, vegetation, and soil, allowing for a dynamic representation of greenhouse gas fluxes that accounts for environmental conditions, soil characteristics, climate, specific crop qualities, and management practices at a daily time step. For example, plant growth is controlled by nutrient availability and water and temperature stress. Nutrient supply is a function of soil organic matter (SOM) decomposition rates and external nutrient additions. Daily maximum/minimum temperature and precipitation, timing and description of management events (e.g. fertilization, tillage, harvest), and soil texture data are model inputs. Key submodels include plant production, organic matter decomposition, soil water and soil temperature by layer, nitrification and denitrification, and methane (CH₄) 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, in press) found in the United States. 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 the original source of the N from which the N₂O emissions are derived. This means, for example, that N₂O emissions from applied N fertilizer cannot be separated from emissions due to N inputs from crop residue. Consequently, emissions could not be partitioned into the IPCC recommended categories (i.e., synthetic fertilizer, organic fertilizer, sewage sludge, and crop residues). Nitrogen losses from major crops due to volatilization and leaching/runoff processes are calculated within DAYCENT based on current conditions. As a result, fertilizer applications have not been reduced by the IPCC default volatilization factors for major crop types—those loss processes are, instead, simulated within the model. Also, other parameters necessary to include as activity data for non-major crop types are simulated dynamically, such as N inputs due to crop residue applications.

There are five steps in estimating N₂O emissions from mineral agricultural soils, cultivated histosols, PRP manure and indirect N₂O emissions from volatilization and leaching/runoff. First, the activity data are derived for mineral agricultural soils, PRP manure and for cultivated histosols. In the second, third, and fourth steps, N₂O emissions from each component is estimated. In the fifth step, emissions from each component are summed to derive total emissions. The remainder of this annex describes the data and each of these steps in detail.

Step 1: Derive Activity Data

The activity data requirements vary for major crops, non-major crops, PRP manure and histosols within the direct emissions category, and for indirect emission estimates. Activity data were derived for each segment of the emission calculation as described below.

Step 1a: N₂O Emissions from non-Histosol Managed Soils

Nitrous oxide emissions from mineral agricultural soils include emissions from both major and non-major cropping systems. Because these crop types are accounted for differently according to the methodology described here, they are discussed in separate subsections below.

Major Crop Types

The activity data required for estimating N₂O emissions resulting from major crop types include the following: a) crop specific N fertilizer amendment rates and timing, b) manure amendment rates and timing, b) land management information, c) the amount of N in sewage sludge and other commercial organic fertilizers that is applied annually, d) daily climate data for every county, e) county-level soil texture data, and f) county level crop areas. The data were assembled in the process-based biogeochemical ecosystem model, DAYCENT, as described elsewhere in this annex. Unlike the IPCC approach, N from fixation and crop residues are not considered activity data when using DAYCENT because they are internally generated by the model. That is, while the model accounts for the contribution of N from fixation and crop residue to N₂O emissions, these are not activity data in the sense that they are not required model inputs.

Nitrogen Fertilizer Amendment Rates and Timing by Agricultural Region. The United States was divided into 63 agricultural regions based on common cropping practices as defined by McCarl et al. (1993) Fertilizer application rates and timing for each agricultural region were based on regional, state, or sub-state estimates for different crops using data from various sources (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 agricultural regional fertilizer rates were based on data for years that were available and on interpolation for years when data were not available. For some crops in some agricultural regions, little or no data were available, so geographic regional means were used. (For example, no data from Alabama later than 1970 were available for corn fertilization rates, therefore mean values for the southeastern United States were used.) To estimate annual fertilizer rates for different crops during 1990 through 2003, the best estimates for crop specific fertilizer rates for this time period were combined with yearly national fertilizer production data. The best estimates of fertilization rates for different crops during 1990 through 2003 were assumed to represent the proportions observed in 1997. The reference year 1997 was chosen because that was the only year for which both crop specific fertilizer and manure amendment rates were available. Fertilizer application rates for years other than 1997 were derived by multiplying 1997 applications by the amount of fertilizer produced in that year relative to the amount produced in 1997 and dividing by the amount of cropped land receiving fertilizer in that year relative to the amount of cropped land receiving fertilizer in 1997. The absolute applications of fertilizers varied from year to year, as indicated by the available consumption information, but the proportions remained the same as were established in 1997. This was done to account for annual fluctuations in the total amount of fertilizer applied and total area of cropped land receiving fertilizer. National annual fertilizer production estimates are from fertilizer statistics (TVA 1991, 1992a, 1993, 1994; AAPFCO 1995, 1996, 1997, 1998, 1999, 2000b, 2002, 2003) and a recent AAPFCO database (AAPFCO 2000a). Synthetic fertilizer rates were reduced by 50 percent for cropped land that received organic N amendments.

Native Vegetation by County. Pre-agricultural land cover for each county was designated according to the native vegetation type defined by the VEMAP (1995) analysis.

Manure Amendment Rates and Timing by Agricultural Region. The United States was divided into 63 agricultural regions based on common cropping practices as defined by McCarl et al. (1993). Prior to 1990, manure application rates and timing for different crops in each agricultural region 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 N fertilizer additions, data for manure were not complete so proxy was used to fill spatial gaps in data and interpolation was used to fill temporal gaps. Manure N applied to major cropping systems during 1990 through 2003 was based on Kellogg et al. (2000) and national managed manure production totals. Managed manure data were obtained from Poe et al. (1999), Safley et al. (1992), and personal communications with agricultural experts (Anderson 2000, Deal 2000, Johnson 2000, Miller 2000, Milton 2000, Stettler 2000, Sweeten 2000, Wright 2000). Livestock weight data were obtained from Safley (2000), USDA (1996, 1998d), and ASAE (1999); daily rates of N excretion from ASAE (1999) and USDA (1996); and information

about the fraction of poultry litter used as a feed supplement from Carpenter (1992). The data from Kellogg et al. (2000) are for the year 1997 and the total amount of manure N accounted for by Kellogg et al. (2000) was less than half of total managed manure N production for that year. To account for the managed manure N that was not applied to soils we subtracted the total manure N accounted for by Kellogg et al. (2000) from total managed manure N and assumed that this difference was volatilized during storage, treatment, and transport. Crop specific rates 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 2003. All managed livestock manure N applied to cropped soils (87 percent of total manure N applied to soils) was applied to major crops simulated by DAYCENT and the manure was assumed to be applied during spring at the same time as synthetic fertilizer. The amount of managed manure N for each livestock type was calculated by first determining the population of animals from which manure is collected and managed. In some instances, the number of animals in managed systems was determined by subtracting the number of animals in pastures, range, and paddock from the total animal population.

Annual animal population data for all livestock types, except horses and goats, were obtained for all years from the USDA National Agricultural Statistics Service (NASS) (USDA 1994b,c; 1995a,b; 1998a,c; 1999a-c; 2000a-g; 2001b-g; 2002b-g; 2003b-g). Horse population data were obtained from the FAOSTAT database (FAO 2003). Goat population data for 1992 and 1997 were obtained from the Census of Agriculture (USDA 1999d); these data were interpolated and extrapolated to derive estimates for the other years in the time series. 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 Census of Agriculture (USDA 1999e).

Information regarding the percentage of managed manure for dairy cattle, beef cattle, and sheep was obtained from communications with personnel from state Natural Resource Conservation Service offices, state universities, NASS, 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 managed manure 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 then multiplied by an average animal mass constant (USDA 1996, USDA 1998d, ASAE 1999, Safley 2000) to derive total animal mass for each animal type in each management system. Total Kjeldahl N¹ excreted per year for each livestock type and management system was then calculated using daily rates of N excretion per unit of animal mass (USDA 1996, ASAE 1999). The total poultry manure N in managed systems was reduced by 4.2 percent, the amount used as a feed supplement (Carpenter 1992). The annual Kjeldahl N was then summed over all livestock types and management systems to derive estimates of the annual manure N applied to soils (Table 3-101).

Table 3-101: Livestock Manure Nitrogen (Gg N)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Managed Applied to Soils	965	991	987	1,007	1,014	1,022	1,015	1,037	1,050	1,049	1,062	1,070	1,069	1,069
Managed Volatilized Before														
Soil Application	1,710	1,756	1,749	1,785	1,797	1,811	1,799	1,838	1,860	1,859	1,882	1,896	1,895	1,895
Used in Cattle Feed	32	32	33	34	35	36	36	37	37	37	38	38	38	38
Pasture, Range, & Paddock	3,816	3,833	3,918	3,961	4,061	4,116	4,110	3,983	3,901	3,859	3,798	3,767	3,759	3,781
Total	6,523	6,612	6,686	6,786	6,907	6,985	6,961	6,896	6,848	6,804	6,779	6,771	6,761	6,760

Crop rotation and Land Management Information by Agricultural Region. The United States was divided into 63 agricultural regions based on common cropping practices as defined by McCarl et al. (1993). Data for agricultural region specific timing and type of cultivation, timing of planting/harvest, and crop rotation schedules were obtained from various sources (Hurd 1930, 1929, Latta 1938, Iowa State College Staff Members 1946, Bogue 1963, Hurt 1994, NASS 2000, NRI 1997, CTCI 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,

¹ Total Kjeldahl N is a measure of organically bound N and ammonia N in both the solid and liquid wastes.

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 proxy data were used to fill spatial gaps in the data sets and interpolation was used to fill temporal gaps

Annual Applications of sewage sludge and other commercial organic fertilizers by agricultural region: The United States was divided into 63 agricultural regions based on common cropping practices as defined by McCarl et al. (1993). No sewage sludge or other organic fertilizers were assumed to be applied to cropped soils before 1990. Agricultural region specific application rates for 1997 for sewage sludge and other organic fertilizers were assumed to be equivalent to manure in terms of amounts of N added per unit area. The 1997 application rates were assumed to be identical to manure because manure N also represents organic matter N additions and we know of no data sets for crop specific application rates for sewage sludge and other organic fertilizers. Amounts of carbon (C) added for sludge and other 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, in DAYCENT, C levels in addition to N inputs influence N cycling and therefore N₂O emissions. Crop-specific areas receiving sewage sludge and other organic fertilizers were obtained by dividing the amount of N applied to cropped soils in the form of sewage sludge and other organic fertilizers by the 1997 crop specific rates for manure addition. Cropped area receiving sewage sludge and other commercial organic fertilizer amendments (less than 1 percent of total cropped land) 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 sewage sludge or other commercial organic fertilizer produced in that year to the sewage sludge or other commercial organic fertilizer produced in 1997. The year 1997 was chosen as the reference year because that was the only year for which crop specific manure amendment rates were available. As with manure, 87 percent of sewage sludge and other organic fertilizers applied to soils was assumed to be applied to crops simulated by DAYCENT.

Estimates of total national annual N additions from land application of sewage sludge were derived from periodic estimates of sludge generation and disposal rates that were developed by EPA. Sewage sludge is generated from the treatment of raw sewage in public or private wastewater treatment works. EPA (1993, 1999) estimated and projected land applications of sewage sludge in the United States through 2000. To estimate annual amounts of N applied as sewage sludge, the dry sewage sludge applications were multiplied by an average N content of 3.3 percent (Metcalf and Eddy 1991). For 2001 through 2003, sludge generation was extrapolated based on wastewater flow rates, while the proportion that was applied to land was held constant based on the year 2000, as no new data were available (Bastian 2002, 2003). Final estimates of annual sewage sludge N applications to land are presented in Table 3-102.

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, 2000b, 2002, 2003) and a recent AAPFCO database (AAPFCO 2000a). 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 2002).

Table 3-102: Commercial Fertilizer Consumption & Land Application of Sewage Sludge (Gg N)

Fertilizer Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Synthetic N														
Applied to														
Agricultural Soils	9,085	9,239	9,302	9,628	10,023	9,686	9,999	10,002	10,011	10,030	9,759	9,465	9,818	9,799
Other Organics*	5	9	6	5	8	11	13	15	13	11	10	8	8	8
Sewage Sludge	78	88	98	109	119	129	133	135	137	142	148	152	156	160
Total	9,168	9,335	9,406	9,743	10,150	9,826	10,145	10,152	10,161	10,184	9,916	9,624	9,982	9968

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

Daily Climate by County: Daily maximum/minimum temperature and precipitation were obtained from DAYMET. DAYMET (Thornton et al. 2000, 1997, Thornton and Running, 1999; <<http://www.daymet.org/>>) is a model that generates daily surface precipitation, temperature, and other meteorological data at 1 km² resolution driven by weather station observations and an elevation model. It is necessary to use computer generated climate data because county level weather station data do not exist. Weather station data are for a point in space, so it is necessary to interpolate between weather stations and account for topography to obtain climate data representative

of the land area within a county that is cropped. DAYMET climate data is available for the United States at 1 km² resolution for 1980 through 2001. For each county, DAYMET climate from the 1 km² cell that was closest to the area-weighted geographical center of cropped land in that county was used to drive DAYCENT.

Soil Properties by County: Soil texture data required by DAYCENT was obtained from VEMAP (1995) and was based on observations. Observed data for soil hydraulic properties needed for model inputs were not available so they were calculated from VEMAP (1995) texture class and Saxton et al.'s (1986) hydraulic properties calculator. VEMAP is at 0.5° resolution so the VEMAP cell that contains the geographic center of each county was identified and the dominant soil type was extracted and applied across the county. Soil texture class and depth from VEMAP and Saxton et al.'s (1986) hydraulic properties calculator were used to represent the soil profile for each county.

Crop Area by Crop Type and by County: County level total crop area data were downloaded from the USDA NASS web site for the years 1990-2003 (<<ftp://www.nass.usda.gov/pub/nass/county/byyear/>>).

Non-Major Crop Types

The activity data required for calculating emissions from non-major crop types includes the following: a) the amount of N in synthetic fertilizers that are applied annually (this was also used for major cropping systems), b) the amount of N in the aboveground biomass of non-major N-fixing crops, and c) the annual amount of N in crop residues retained on soils where non-major crops are produced.

Application of synthetic and organic commercial fertilizers: Annual commercial fertilizer consumption data for the United States were taken from annual publications of synthetic and organic fertilizer statistics (TVA 1991, 1992a, 1993, 1994; AAPFCO 1995, 1996, 1997, 1998, 1999, 2000b, 2002, 2003) and a recent AAPFCO database (AAPFCO 2000a). These data were manipulated in several ways to derive the specific activity data needed for the inventory. First, the manure and sewage sludge portions of the organic fertilizers were subtracted from the total organic fertilizer consumption data because these N additions are accounted for under “manure application” and “sewage sludge application.”² Second, 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. For sewage sludge the assumed N content was 3.3 percent (Metcalf and Eddy 1991). For other organic fertilizers, 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 2002). The synthetic fertilizer data are recorded in units of N, so these data did not need to be converted. Lastly, both the synthetic and organic fertilizer consumption data are recorded in “fertilizer year” totals (i.e., July to June); therefore, the data were converted to calendar year totals. This was done by assuming that approximately 35 percent of fertilizer usage occurred from July to December, and 65 percent from January to June (TVA 1992b). July to December values were not available for calendar year 2002, so a “least squares line” statistical extrapolation using the previous twelve years of data was used to arrive at an approximate value. Annual consumption of commercial fertilizers in units of N and on a calendar year basis is presented in Table 3-102.

To estimate total fertilizer N applied to non-major crop types a process of elimination approach was used. Estimates for N fertilizer applied to settlements and forest lands were added to the amount of N fertilizer applied to major crops. This sum was subtracted from total fertilizer consumed in the United States and this difference was assumed to be applied to non-major crops.

Production of N-fixing crops: Annual production statistics for non-major bean and pulse crops were taken from U.S. Department of Agriculture crop production reports (USDA 1994a, 1998b, 2000i, 2001a, 2002a, 2003a). The production statistics for beans and pulses were obtained in tons of product, which needed to be 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 mass ratios for soybeans and peanuts, and the dry matter content for soybeans, were obtained from Strehler and

² Organic fertilizers included in these publications are manure, compost, dried blood, sewage sludge, tankage, and “other.” (Tankage is dried animal residue, usually freed from fat and gelatin). The manure and sewage sludge used as commercial fertilizer are accounted for elsewhere, so these were subtracted from the organic fertilizer statistics to avoid double counting.

Stützle (1987). The dry matter content for peanuts was obtained through personal communications with Ketzis (1999). The residue to crop product ratios and dry matter contents for the other beans and pulses were estimated by taking averages of the values for soybeans and peanuts. The IPCC default N content of 3 percent (IPCC/UNEP/OECD/IEA 1997) was used for all beans and pulses.³ As DAYCENT did not simulate 100 percent of the grassland, N inputs from forage legumes not accounted for by DAYCENT were included here. The amount of N input accounted for by the pastures simulated by DAYCENT (residue N inputs are a DAYCENT output) was subtracted from total N inputs from forage legumes. This difference was assumed to represent the N inputs from forage legumes not simulated by DAYCENT.

The final estimates of annual aboveground biomass production, in units of N, are presented in Table 3-103. The residue to crop product mass ratios and dry matter fractions used in these calculations are presented in Table 3-104.

Table 3-103: 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
Peanuts	84	115	100	79	99	81	86	83	93	90	76	100	78	97
Dry Edible Beans	98	102	68	66	87	93	84	89	92	100	80	59	90	68
Dry Edible Peas	7	11	8	10	7	14	8	17	18	14	11	11	13	16
Austrian Winter Peas	+	+	+	+	+	+	+	+	+	+	+	+	+	1
Lentils	3	5	5	6	6	7	4	7	6	7	9	9	8	7
Wrinkled Seed Peas	3	3	2	3	2	3	2	2	2	2	2	2	2	2
Total	195	237	183	164	202	198	184	199	211	213	178	182	191	191

+ Less than 0.5 Gg N.

Note: Totals may not sum due to independent rounding.

Table 3-104: Key Assumptions for Non-Major Crop Production and Crop Residue

Crop	Residue/Crop Ratio	Residue Dry	
		Matter Fraction	Residue Nitrogen Fraction
Peanuts	1.0	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
Oats	1.3	0.92	0.007
Rye	1.6	0.90	0.0048
Millet	1.4	0.89	0.007
Rice	1.4	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).⁴ It was also assumed that 100 percent of unburned rice residue is left on the field.⁵

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,

³ 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.

⁴ Although the mode of residue application would likely affect the magnitude of N₂O emissions, an emission estimation methodology that accounts for this has not been developed.

⁵ 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, 2001a, 2002a, 2003a). Production statistics for rice in Florida and Oklahoma, which are not recorded by USDA, were estimated by applying an average rice crop yield for Florida (Schueneman and Deren 2002) to annual Florida and Oklahoma rice areas (Schueneman 1999, 2001, Deren 2002, Kirstein 2003, Cantens 2004, Lee 2003, 2004). Residue to crop product ratios for all crops were obtained from, or derived from, Strehler and Stützle (1987). The dry matter content of rice residue was obtained from Turn et al. (1997). Soybean and millet residue dry matter contents were obtained from Strehler and Stützle (1987). Peanut, oat, and rye residue dry matter contents were obtained through personal communications with Ketzis (1999). Dry matter contents for all other beans and pulses were estimated by averaging the values for soybeans and peanuts. The residue N content of rice is from Turn et al. (1997). The N content of soybean residue is from Barnard and Kristoferson (1985), the N contents of peanut, oat, and rye residue are from Ketzis (1999), and the N content of millet residue is 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 derived using information obtained from 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 final estimates of residue retained on soil, in units of N, are presented in Table 3-105. 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 3-104.

Table 3-105: 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
Oats	39	27	32	23	25	18	17	18	18	16	16	13	13	16
Rye	2	2	2	2	2	2	1	1	2	2	1	1	1	1
Millet	3	3	3	3	3	3	3	3	3	3	1	3	0	2
Rice	51	52	60	52	65	59	57	65	68	74	67	77	78	83
Peanuts	13	18	16	13	16	13	14	13	15	14	12	16	12	15
Dry Edible Beans	11	12	8	7	10	10	10	10	10	11	9	7	10	8
Dry Edible Peas	1	1	1	1	1	2	1	2	2	2	1	1	1	2
Austrian Winter Peas	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Lentils	+	1	1	1	1	1	0	1	1	1	1	1	1	1
Wrinkled Seed Peas	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Total	121	116	123	101	122	107	103	114	119	123	110	120	118	128

+ Less than 0.5 Gg N.

Note: Totals may not sum due to independent rounding.

Step 1b: Cultivation of Histosols

Estimates of the areas of histosols cultivated in 1982, 1992, and 1997 were obtained from the USDA's *1997 National Resources Inventory* (USDA 2000h, as extracted by Eve 2001, and revised by Ogle 2002).⁶ These areas were grouped by broad climatic region⁷ using temperature and precipitation estimates from Daly et al. (1994, 1998), and then further aggregated to derive a temperate total and a sub-tropical total. These final areas were then linearly interpolated to obtain estimates for 1990 through 1996, and linearly extrapolated to obtain area estimates for 1998 through 2002 (Table 3-106).

Table 3-106: Cultivated Histosol 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

⁶ 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.

⁷ 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.

1997	439	196
1998	441	197
1999	441	197
2000	445	197
2001	447	198
2002	449	198
2003	451	199

Step 1c: Direct N₂O Emissions from Pasture, Range, and Paddock Livestock Manure

Estimates of N₂O emissions from this component were based on livestock manure that is not managed in manure management systems, but instead is deposited directly on soils by animals in pasture, range, and paddock. The livestock included in this component were: dairy cattle, beef cattle, swine, sheep, goats, poultry, and horses.

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 1999e) 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 each region of the United States. This percentage was applied to the total annual dairy cow and heifer state population data for 1990 through 2002, which were obtained from the USDA National Agricultural Statistics Service (USDA 1995a; 1999a; 2000a,b; 2001b,c; 2002b,c, 2003b,c).

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 1995a; 1999a; 2000a,b; 2001b,c; 2002b,c; 2003b,c) 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 1999e) 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, 1998a, 2000e, 2001d; 2002d, 2003d) to determine the population of swine on pasture, range, and paddock.

Sheep: It was assumed that all sheep and lamb manure not deposited on feedlots was deposited on pasture, range, and paddock (Anderson 2000). Sheep population data were obtained from the USDA National Agricultural Statistics Service (USDA 1994c, 1999c, 2000g, 2001f, 2002f, 2003f). However, population data for lamb and sheep on feed were not available after 1993. The number of lamb and sheep on feed for 1994 through 2002 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 on “feedlots”; they may have been on pasture/crop residue supplemented by feed. Data for those feedlot animals versus pasture/crop residue were provided only for lamb in 1993. To calculate the populations 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).

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 1999d). The data for 1992 were used for 1990 through 1992 and the data for 1997 were used for 1997 through 2002. Data for 1993 through 1996 were 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, 2000c, 2000d, 2000f, 2001f, 2002f, 2003f). 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 2003).

For each animal type, the population of animals within pasture, range, and paddock systems was multiplied by an average animal mass constant (USDA 1996, ASAE 1999, USDA 1998d, Safley 2000) to derive total animal mass for each animal type. Total Kjeldahl N excreted per year was then calculated for each animal type using daily rates of N excretion per unit of animal mass (USDA 1996, ASAE 1999). Annual N excretion was then summed over all animal types to yield total N in pasture, range, and paddock manure (Table 3-101).

Step 1d: Indirect N₂O Emissions from Managed Soils of all Land Use Types

Indirect emissions from mineral agricultural soils, settlements, forest lands, and PRP manure were calculated based on the quantity of N added to the soils according to the methods described above. Volatilization of N from manure during storage, treatment, and transport before soil application was also considered. Through volatilization, some of the N applied as commercial fertilizer, livestock manure, and other organic inputs enters the atmosphere as NH₃ and NO_x, and subsequently returns to soils through atmospheric deposition, thereby enhancing N₂O production. Additional N is lost from soils through leaching and runoff, and enters groundwater and surface water systems, from which a portion is emitted as N₂O. These two indirect emission pathways are treated separately. The activity data for commercial fertilizer and sewage sludge are the same as those used in the calculation of direct emissions from agricultural mineral soils, and may be found in Table 3-102. However, the amount of N available to produce indirect N₂O emissions was calculated differently for major and non-major crop types, as discussed below.

For non-major crop types, forest lands, and settlements, commercial fertilizer additions were multiplied by the respective IPCC default emission factor (10 percent for volatilization, 30 percent for leaching/runoff) to estimate indirect N₂O emissions from those lands. Fertilizer N additions for non-major crop types were obtained as explained above for direct soil emissions and estimates for forest lands and settlements are explained in the LUCF chapter.

The N available for producing indirect emissions resulting from the cultivation of major crop types was calculated by DAYCENT. DAYCENT's simulation accounts for volatilization and leaching/runoff from all N in the soil system, regardless of the source of that N, according to specific environmental and management conditions. N₂O that is emitted indirectly from N applied as commercial fertilizer, sewage sludge, and livestock manure, and from other management practices (e.g., plowing, irrigating, harvesting). Nitrogen from managed manure not applied to crops (or pastures) was assumed to volatilize before application to soils. These data are presented in Table 3-101.

The N available for producing indirect emissions resulting from PRP manure was calculated by DAYCENT for pastures and by the default IPCC emission factor for PRP manure not simulated by DAYCENT. Nitrogen volatilization and N leached/runoff from pastures were calculated by DAYCENT based on environmental conditions and grazing management. To estimate the amount of N contributing to indirect emissions from PRP manure not simulated by DAYCENT, the manure N accounted for by DAYCENT (soil manure N inputs are a DAYCENT output) was subtracted from total PRP manure N. This difference was assumed to represent the manure N inputs from PRP manure not simulated by DAYCENT.

Step 2: Estimate Direct N₂O Emissions from Agricultural Soils Due to Nitrogen Additions, Cultivation of Non-Histosols with Major Crops, and Cultivation of Histosols

In this step, N₂O emissions were calculated for each of three parts (direct N₂O emissions due to the N additions and cultivation of major crop types, N additions to non-major crop types, and direct N₂O emissions due to histosol cultivation), which were then summed to yield total direct N₂O emissions from agricultural soils (Table 3-107).

Step 2a: Direct N₂O Emissions Due to Nitrogen Additions and Cultivation of non-Histosols

To estimate these emissions, two methods were combined. The DAYCENT ecosystem model was used to estimate emissions from major row crops and managed pastures while the IPCC emission factor methodology was used to estimate emissions from crops not simulated by DAYCENT.

Major Crops: 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 and to provide natural baseline greenhouse gas fluxes to compare with those from agriculture. Simulation of plow out and historical cropping were needed to establish modern day SOM levels. Proper organic soil carbon simulation is important because N₂O emissions are sensitive to SOM.

Corn, soy, wheat, alfalfa hay, other hay, sorghum, and cotton are defined as major crops and were simulated in every county where they are found. These crops represent approximately 90 percent of total principle cropland in the United States. Principle 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. Organic matter amendments include separate simulations for manure, sewage sludge, and other commercial organic fertilizer additions. For rotations that include a cycle that repeats every two or more years (e.g. corn/soy, wheat/corn/fallow) different simulations were performed where the initial crop was varied but the sequence was not altered. 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 cases where the same crop was grown in the same year in two or more distinct rotations for a region, average values for each output were calculated. 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 hence, N₂O emissions. These simulations included approximately 90 percent of principle cropland area and approximately 86 percent of total cropland area. Total cropland area includes principle crops plus fruit trees, nut trees, and commercial vegetables.

DAYCENT simulated modern and natural direct soil N₂O emissions, NO₃ that is leached and runoff, and volatilized NO_x and NH₃ for each county in the United States. To more accurately account for the anthropogenic portion of soil N₂O emissions, simulated direct and indirect N₂O emissions from the native condition were subtracted from those for recent modern cropping for each crop in each county. For each crop in each county, 4 separate sets of simulations for recent modern cropping were performed: 1 to represent the land area that received only synthetic fertilizer N additions, 1 to represent the land area that received manure N additions, 1 to represent the land area that received sewage sludge N additions, and 1 to represent the land area that received other organic matter 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. Emissions from separate simulations of organic matter amendments were multiplied by the applicable manured, sludged, or other organically fertilized area for that crop. Emissions for the respective non-organic matter amended and organic matter amended areas were summed to obtain county and state level totals. State-level totals were summed to get national totals for direct soil N₂O emissions, as well as indirect N₂O emissions from N volatilization and leaching/runoff.

Non-Major Crops: To estimate direct N₂O emissions from N additions to non-major crops, the amounts of applied N were first reduced by the IPCC default volatilization fraction (10 percent). The unvolatilized amounts were then summed, and the total remaining N was multiplied by the IPCC default emission factor of 0.0125 kg N₂O/kg N (IPCC/UNEP/OECD/IEA 1997). The volatilization assumptions are described below.

- *Application of synthetic fertilizer:* The total amounts of N applied in the form of synthetic commercial fertilizers to non-major crops were reduced by 10 percent to account for the portion that volatilizes to NH₃ and NO_x (IPCC/UNEP/OECD/IEA 1997).

- *Application of livestock manure:* All livestock manure N applied to cropped soils was assumed to be applied to major crops. Therefore, it was unnecessary to make adjustments according to the IPCC method for non-major crop types.
- *Application of sewage sludge:* All sewage sludge N applied to cropped soils was assumed to be applied to major crops. Therefore, it was unnecessary to make adjustments according to the IPCC method for non-major crop types.
- *Retention of crop residue:* None of the N in retained crop residue was assumed to volatilize for non-major crops.
- *Production of N fixing non-major crops:* None of the N in aboveground biomass of N-fixing crops was assumed to volatilize.

Step 2b: Total Direct Emissions from non-Histosol Cropping

Direct N₂O emissions from major and non-major cropped were summed to obtain total direct emissions for non-histosol cropped soils.

Step 2c: Direct N₂O Emissions Due to Cultivation of Histosols

To estimate annual N₂O emissions from histosol cultivation, the temperate histosol area was multiplied by the IPCC default emission factor for temperate soils (8 kg N₂O-N/ha cultivated; IPCC 2000), and the sub-tropical histosol area was multiplied by the average of the temperate and tropical IPCC default emission factors (12 kg N₂O-N/ha cultivated; IPCC 2000).

Step 2d: Estimate Total Direct N₂O Emissions

In this step, total direct N₂O emissions from agricultural soils are calculated by summing direct emissions from N cycling and applications to mineral soils with emissions resulting from the cultivation of histosols (Table 3-107).

Table 3-107: Direct N₂O Emissions from Agricultural Soils (Tg CO₂ Eq.)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Mineral Soils	97	100	95	101	105	100	110	111	114	108	114	110	116	112
Histosol Cultivation	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total	100	103	97	103	108	103	113	114	117	111	116	113	118	115

+ Less than 0.5 Tg CO₂ Eq.

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

Step 3: Estimate Direct N₂O Emissions from Pasture, Range, and Paddock Livestock Manure

To estimate direct N₂O emissions from soils due to the deposition of pasture, range, and paddock manure, the total N excreted by these animals was multiplied by the IPCC default emission factor (0.02 kg N₂O-N/kg N excreted) (see Table 3-108).

Table 3-108: Direct N₂O Emissions from Pasture, Range, and Paddock Livestock Manure (Tg CO₂ Eq.)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Beef Cattle	35	35	35	36	38	38	41	38	38	36	35	37	37	36
Dairy Cows	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Swine	+	1	1	+	+	+	+	+	+	+	+	+	+	0
Sheep	+	+	+	+	+	+	+	+	+	+	+	+	+	0
Goats	+	+	+	+	+	+	+	+	+	+	+	+	+	0
Poultry	+	+	+	+	+	+	+	+	+	+	+	+	+	0
Horses	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total	40	40	40	41	43	43	46	42	42	40	40	41	41	40

+ Less than 0.5 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Step 4: Estimate Indirect N₂O Emissions Induced by Applications of Nitrogen, Cultivation of non-Histosols and Deposition of PRP Manure

In this step, N₂O emissions were calculated for each of two indirect emission pathways (N₂O emissions due to volatilization, and indirect N₂O emissions due to leaching and runoff), which were then summed to yield total direct N₂O emissions from cultivated soils.

Step 4a: Indirect Emissions Due to Volatilization

Indirect emissions from volatilization were calculated according to the amount of N that indirectly deposits on soils or water from the cultivation of major crops, the cultivation of non-major crops, N applied in settlements, N applied to forest lands, PRP manure, and storage, treatment and transport of managed manure.

Volatilization that resulted from major crop types was calculated based on the simulation of N-cycling occurring in the DAYCENT ecosystem model, which calculates NO_x and NH₃ volatilization internally according to the specific management practices and environmental conditions at the county scale. Volatilization was summed across all counties in the conterminous United States to provide a national value for volatilized N from major cropping systems. Managed manure that volatilized during transport, treatment, and storage before application to crops was included in the volatilization from major cropping systems. The amount of managed manure volatilized during storage, treatment, and transport was calculated by subtracting manure consumed by cropped soils based on estimates by Kellogg et al. (2000) and Edmonds et al. (2003) from values of managed manure production. In contrast to the IPCC methodology that only considers volatilization of manure that was applied to soils, the manure that was assumed to volatilize during storage, treatment, and transport was included in the volatilization component of indirect N₂O emissions.

To estimate volatilization resulting from the cultivation of non-major crops and the N applied to settlements and forest lands, the amount of commercial fertilizer N applied to these soils was multiplied by the IPCC default fraction of N (10 percent) that is assumed to volatilize as NH₃ and NO_x.

To estimate volatilization from PRP manure the volatilization of deposited manure from pastures simulated by DAYCENT was added to the volatilization from PRP manure not simulated by DAYCENT. The default IPCC emission factor for volatilization was applied to the PRP manure N not simulated by DAYCENT.

Volatilized N for major crops was added to volatilized N from non-major crops, settlements, forest lands, PRP manure and storage, treatment, and transport of managed manure. The total volatilized N was multiplied by the IPCC default emission factor of 0.01 kg N₂O-N/kg N (IPCC/UNEP/OECD/IEA 1997). These emission estimates are presented in Table 3-109.

Table 3-109: Indirect N₂O Emissions (Tg CO₂ Eq)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Volatilization and Atm. Deposition	16	16	16	16	16	16	16	17	16	16	17	16	17	16
Cropland, Settlements, and Forestland	10	10	11	11	11	11	11	11	11	11	12	11	11	11
Pasture, Range & Paddock Livestock Manure	5	5	5	5	5	6	5	5	5	5	5	5	5	5
Surface Leaching & Run-off	97	89	79	86	71	82	92	80	93	76	91	86	76	82
Cropland, Settlements, and Forestland	77	67	58	64	51	62	70	58	71	58	70	66	57	62
Pasture, Range & Paddock Livestock Manure	20	22	21	22	20	20	22	22	21	18	20	21	19	20
Total	113	104	95	102	87	98	108	96	109	92	108	103	93	98

Note: Totals may not sum due to independent rounding.

Step 4b: Indirect Emissions Due to Leaching and Runoff

Indirect emissions from leaching and runoff were calculated according to the amount of N that indirectly entered the soil system from the cultivation of major crops, as well as the cultivation of non-major crop types.

Leaching/runoff that resulted from major crop types was calculated based on the simulation of N cycling occurring in the DAYCENT ecosystem model, which calculates NO₃⁻ losses to leaching and runoff internally according to the specific management practices and environmental conditions at the county scale. Leached and runoff N was summed across all counties in the conterminous United States to provide a national value for leached/runoff N from major cropping systems.

To estimate leaching and runoff from the cultivation of non-major crops, settlements, and forests, the amount of commercial fertilizer N applied to these soils was multiplied by the IPCC default fraction of N that is leached and runoff (30 percent).

To estimate leaching/runoff from PRP manure the N leaching/runoff from pastures simulated by DAYCENT was added to the N leaching/runoff from PRP manure not simulated by DAYCENT. The default IPCC emission factor for N leaching/runoff was applied to the PRP manure N not simulated by DAYCENT.

Leached/runoff N from major crops was added to that from non-major cropping systems, settlements, forests, and PRP manure. The total N was multiplied by the IPCC default emission factor of 0.025 kg N₂O-N/kg N (IPCC/UNEP/OECD/IEA 1997) to provide an indirect emission estimate from this source. These emission estimates are presented in Table 3-109.

Step 5: Estimate Total N₂O Emissions

In this step, total emissions are calculated by summing direct emissions from mineral agricultural soils, histosols, and pasture, range, and paddock livestock manure with indirect emissions (Table 3-110) to determine comprehensive N₂O emissions resulting from agriculture.

Table 3-110: Total N₂O Emissions (Tg CO₂ Eq)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Total Direct	140	143	139	146	151	147	159	156	159	151	156	154	160	155
Direct emissions from mineral agricultural soils	97	100	95	101	105	100	110	111	114	108	114	110	116	112
Direct emissions from histosols	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Direct emissions from pasture, range, and paddock livestock manure	40	41	41	42	43	43	46	42	42	40	40	41	41	40
Total Indirect	113	104	95	102	87	98	108	96	109	92	108	103	93	98
Volatilization	16	16	16	16	16	16	16	17	16	16	17	16	17	16
Leaching/Runoff	97	89	79	86	71	82	92	80	93	76	91	86	76	82
Total Emissions	253	248	233	248	238	245	267	252	268	243	264	257	253	254

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 annex expands on the methodology used to calculate net changes in carbon (C) stocks in forest ecosystems and in harvested wood products. Some of the details of C conversion factors and procedures for calculating net CO₂ flux for forests are provided below; 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 U.S. 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 FIADB, version 1.7. More complete information about these data is available at an FIA Internet site (<<http://ncrs2.fs.fed.us/4801/fiadb/index.htm>>). All FIADB surveys used for C stock estimates were obtained from this site on or before August 10, 2004.

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 in which the data were collected. If data were collected over a number of years, an average value is assigned. 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 forestlands 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 3-111.

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 the 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 LULUCF *Good Practice Guidance* (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 LULUCF *Good Practice Guidance* (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 Smith et al. (2003) and are functions of plot level growing stock volume of live trees, forest type, and region. C mass of wood is approximately 50 percent of dry weight (IPCC/UNEP/OECD/IEA 1997). The minimum-sized tree included in 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. Again, separate estimates are made for whole-trees and aboveground-only portions so belowground mass is based on the difference between the two estimates. 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). Soil C estimates provided with the 2003 Inventory (EPA 2003) were also based on STATSGO data, but the current methods differ from previous summaries. Estimates presented here are based on the general approach described by Amichev and Galbraith (2004). In their procedure, SOC was calculated for the conterminous U.S. 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.

A historical focus of the FIA program was to provide information on timber resources of the U.S. 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 measurements were not collected on individual tree measurements. However, all annualized surveys initiated since 1998 have followed a new national plot design for all forestlands (Miles et al. 2001, Alerich et al. unpublished <<http://ncrs2.fs.fed.us/4801/fiadb/index.htm>>). 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 present in the surveys collected before 1998 have been filled by assigning regional average C densities calculated from later, complete, inventories. This has had the effect of generating an estimate for C stock with no net change in C density on those lands with gaps in past surveys.

The FORCARB2 C pools were configured to form the IPCC (2003) recommended storage pools. Aboveground portions of live trees and understory vegetation were pooled to form the aboveground biomass pool; similarly, belowground portions were pooled to form belowground biomass. Standing dead trees and down dead wood were pooled to dead wood. The forest floor estimate corresponds to the litter pool. Average C density values for forest ecosystem C pools according to region and forest types within regions are provided in Table 3-112. Note that C densities reflect the surveys included in the 2002 RPA inventory summary, 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 is likely to reduce the regional average for C density in forest types managed for timber production, such as Southern pines.

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 3-111). C stocks were calculated separately for each state based on inventories available since 1990 and for the most recent inventory prior to 1990. Thus, the number of separate stock estimates for each state was one less than the number of available inventories. 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. 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 3-113 and Table 3-114, 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 that is burned was estimated. For products entering dumps or landfills, the proportion of C emitted as CO₂ or CH₄ was estimated using the estimated maximum proportion of wood and paper converted to CO₂ or CH₄ 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. For comparison, imports (which were not included in the harvested wood net flux estimates) increased from 7.2 Tg C per year in 1990 to 13 Tg C per year in 2002. Skog and Nicholson (1998) go into further detail in their description of this methodology. Summaries of net fluxes and stocks for harvested wood in products and landfills are in Table 3-113 and Table 3-114.

Table 3-111. Source of Forest Inventory and Average Year of Field Survey Used to Estimate Statewide Carbon Stocks.

State ^a	Source of Inventory Data ^b	Average Year Assigned to Inventory ^c
Alabama	1997 RPA	1990
	FIADB, cycle 7	1999
	FIADB, cycle 4	2002
Arizona, NFS	1987 RPA	1985
	FIADB, cycle 2	1995
	FIADB, cycle 3	2002
Arizona, all other	1997 RPA	1985
	FIADB, cycle 2	1996
	FIADB, cycle 3	2002
Arkansas	1987 RPA	1978
	FIADB, cycle 1	1995
	FIADB, cycle 3	2001
California, NFS	1987 RPA	1980
	1997 RPA	1991
	2002 RPA	1997
California, all other	1987 RPA	1982
	1997 RPA	1994
	1997 RPA	1984
Colorado, NFS	2002 RPA	1990
	2002 RPA	1982
	2002 RPA	1982
Colorado, all other ^d	1997 RPA	1985
	FIADB, cycle 4	1998
	1997 RPA	1986
Delaware	1997 RPA	1986
	FIADB, cycle 4	1999
	1987 RPA	1987
Florida	1997 RPA	1994
	1987 RPA	1982
	1997 RPA	1996
Georgia	1987 RPA	1982
	1997 RPA	1996
	1987 RPA	1982
Idaho, NFS	1997 RPA	1996
	1987 RPA	1982
	2002 RPA	1993
Idaho, all other	1987 RPA	1981
	2002 RPA	1990
	1997 RPA	1985
Illinois	FIADB, cycle 4	1997
	FIADB, cycle 5	2002
	1987 RPA	1987
Indiana	FIADB, cycle 4	1997
	FIADB, cycle 5	2000
	2002 RPA	1989
Iowa	2002 RPA	1989

	FIADB, cycle 4	2001
Kansas	1987 RPA	1987
	FIADB, cycle 4	1994
	FIADB, cycle 5	2002
Kentucky	2002 RPA	1987
	FIADB, cycle 4	2001
Louisiana	1987 RPA	1984
	2002 RPA	1991
	FIADB, cycle 3	2002
Maine	1987 RPA	1983
	FIADB, cycle 4	1995
	FIADB, cycle 5	2000
Maryland	1997 RPA	1986
	FIADB, cycle 5	1999
Massachusetts	1997 RPA	1985
	FIADB, cycle 4	1997
Michigan	1987 RPA	1987
	FIADB, cycle 5	1992
	FIADB, cycle 6	2001
Minnesota	2002 RPA	1989
	FIADB, cycle 12	2000
Mississippi	1987 RPA	1977
	2002 RPA	1993
Missouri	2002 RPA	1988
	FIADB, cycle 5	2001
Montana, NFS	1987 RPA	1987
	2002 RPA	1995
	FIADB, cycle 2	2003
Montana, all other	2002 RPA	1988
	FIADB, cycle 2	2003
Nebraska	1987 RPA	1987
	FIADB, cycle 3	1994
	FIADB, cycle 4	2002
Nevada, NFS	1987 RPA	1984
	2002 RPA	1996
Nevada, all other	1987 RPA	1980
	1997 RPA	1989
New Hampshire	1997 RPA	1983
	FIADB, cycle 5	1996
	FIADB, cycle 6	2003
New Jersey	1997 RPA	1987
	FIADB, cycle 4	1998
New Mexico, NFS	1987 RPA	1985
	FIADB, cycle 2	1997
New Mexico, all other	1997 RPA	1987
	FIADB, cycle 2	1999
New York	1987 RPA	1987
	FIADB, cycle 5	2002
North Carolina	1987 RPA	1984
	1997 RPA	1990
North Dakota	1987 RPA	1987
	FIADB, cycle 3	1994
	FIADB, cycle 4	2001
Ohio	1987 RPA	1987
	FIADB, cycle 5	2001
Oklahoma	1987 RPA	1986
	2002 RPA	1991
Oregon, eastern NFS	1987 RPA	1987
	2002 RPA	1994
	FIADB, cycle 5	2001
Oregon, eastern all other	1987 RPA	1977
	1997 RPA	1992

	FIADB, cycle 5	2001
Oregon, western NFS	1987 RPA	1987
	2002 RPA	1995
	FIADB, cycle 5	2001
Oregon, western all other	1997 RPA	1988
	FIADB, cycle 5	2001
Pennsylvania	2002 RPA	1989
	FIADB, cycle 5	2001
Rhode Island	1997 RPA	1985
	FIADB, cycle 4	1998
South Carolina	1987 RPA	1986
	1997 RPA	1992
	FIADB, cycle 3	2000
South Dakota, NFS	1997 RPA	1985
	2002 RPA	1999
	FIADB, cycle 5	2001
South Dakota, all other	1987 RPA	1985
	FIADB, cycle 4	1995
	FIADB, cycle 5	2002
Tennessee	1997 RPA	1989
	FIADB, cycle 6	1998
	FIADB, cycle 4	2001
Texas	1987 RPA	1985
	2002 RPA	1992
	FIADB, cycle 3	2002
Utah	1987 RPA	1977
	2002 RPA	1993
	FIADB, cycle 2	2001
Vermont	1997 RPA	1983
	FIADB, cycle 5	1997
Virginia	1987 RPA	1986
	1997 RPA	1991
	FIADB, cycle 3	1999
Washington, eastern NFS	1987 RPA	1987
	2002 RPA	1995
	FIADB, cycle 5	2002
Washington, eastern all other	1987 RPA	1980
	2002 RPA	1991
	FIADB, cycle 5	2002
Washington, western NFS	1987 RPA	1987
	2002 RPA	1995
	FIADB, cycle 5	2002
Washington, western all other	2002 RPA	1989
	FIADB, cycle 5	2002
West Virginia	2002 RPA	1988
	FIADB, cycle 5	2000
Wisconsin	1987 RPA	1987
	FIADB, cycle 5	1995
	FIADB, cycle 6	2001
Wyoming, NFS	1997 RPA	1984
	2002 RPA	1997
	FIADB, cycle 2	1999
Wyoming, all other	2002 RPA	1983
	FIADB, cycle 2	2001

^a Inventories for 11 western states were separated into National Forest System (NFS) and all other forestlands (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 1.7 as available on Internet August 10, 2004.

^c Rounded to the nearest year

^d Assume no change in Colorado non-NFS forestland

Table 3-112. Average Carbon Density (Mg/ha) by Carbon Pool and Forest Area (1000 ha) for Forest Types Based on the Inventory in the 2002 RPA Database.

Region (States) Forest Types	Above- ground Biomass	Below- ground Biomass	Dead Wood	Litter	SOC	Forest Area
Carbon Density (Mg/ha)						(1000 ha)
Northeast						
(CT,DE,MA,MD,ME,NH,NJ,NY,PA,RI,VT,WV)						
White-red-jack pine	69.7	14.3	8.0	13.3	78.1	2,615
Spruce-fir	46.9	9.9	10.9	32.4	98.0	3,373
Loblolly-shortleaf pine	46.3	9.4	5.7	12.5	77.5	591
Oak-pine	66.6	13.1	8.7	27.2	66.9	987
Oak-hickory	71.1	13.5	9.5	7.9	53.1	10,394
Elm-ash-cottonwood	49.8	9.6	7.5	23.7	111.7	1,104
Maple-beech-birch	65.2	12.5	9.9	26.5	69.6	13,477
Aspen-birch	44.6	8.7	6.8	8.9	87.4	1,663
Minor types and nonstocked	51.3	9.8	7.7	6.6	100.2	208
Northern Lake States						
(MI,MN,WI)						
White-red-jack pine	42.1	8.8	6.0	12.0	120.8	1,739
Spruce-fir	37.3	7.9	7.0	31.3	261.8	3,561
Oak-hickory	68.7	13.0	10.5	8.1	97.1	2,479
Elm-ash-cottonwood	47.8	9.2	8.4	24.4	179.9	1,847
Maple-beech-birch	67.5	13.0	10.7	25.9	134.3	5,738
Aspen-birch	43.2	8.3	8.7	8.4	146.1	5,514
Minor types and nonstocked	6.2	1.1	3.7	4.8	206.3	135
Northern Prairie States						
(IA,IL,IN,KS,MO,ND,NE,OH,SD)						
White-red-jack pine	54.3	11.3	8.6	11.6	61.5	75
Loblolly-shortleaf pine	35.6	7.4	5.6	12.0	36.5	325
Ponderosa pine	43.9	9.3	6.8	14.2	48.5	529
Oak-pine	45.7	8.9	6.5	24.5	38.6	586
Oak-hickory	61.7	11.7	8.4	7.6	47.2	8,405
Elm-ash-cottonwood	66.9	12.6	10.4	24.1	84.0	1,675
Maple-beech-birch	54.5	10.3	7.6	24.3	70.7	3,080
Aspen-birch	55.3	10.4	8.9	8.7	71.0	116
Minor types and nonstocked	31.0	5.8	7.4	8.2	65.3	390
South Central						
(AL,AR,KY,LA,MS,OK,TN,TX)						
Longleaf-slash pine	43.5	8.9	5.2	11.2	55.5	1,249
Loblolly-shortleaf pine	44.2	9.0	5.2	10.5	41.9	11,563
Oak-pine	47.3	9.2	6.6	9.3	41.7	7,599
Oak-hickory	54.3	10.2	7.3	5.9	38.6	21,787
Oak-gum-cypress	65.7	12.4	9.3	6.3	52.8	6,835
Elm-ash-cottonwood	59.7	11.3	8.5	5.8	49.9	765
Minor types and nonstocked	33.0	6.1	3.3	6.1	54.7	1,210
Southeast						
(FL,GA,NC,SC,VA)						
White-red-jack pine	78.6	15.8	9.6	12.4	52.4	264
Longleaf-slash pine	35.2	7.2	3.9	9.7	110.0	4,362
Loblolly-shortleaf pine	43.3	8.9	4.8	9.4	72.9	9,427
Oak-pine	48.5	9.5	4.7	9.1	61.4	4,598
Oak-hickory	68.0	12.8	6.3	6.2	45.3	11,081
Oak-gum-cypress	68.2	13.1	7.2	6.4	158.0	5,585
Elm-ash-cottonwood	59.9	11.5	6.5	5.9	95.7	338
Minor types and nonstocked	79.4	15.1	7.4	7.6	76.8	183
Pacific Northwest, Westside						
(Western OR and WA)						
Douglas-fir	122.2	25.5	16.4	31.6	94.8	5,309
Fir-spruce	161.2	34.0	55.7	37.2	62.1	950
Hemlock-Sitka spruce	129.8	27.3	35.6	34.4	116.3	2,292
Hardwoods	93.3	18.2	14.8	8.6	95.7	2,075
Minor types and nonstocked	50.8	10.3	9.5	19.0	65.1	425
Pacific Northwest, Eastside						

(Eastern OR and WA)						
Douglas-fir	72.0	15.0	9.7	36.6	94.8	2,200
Ponderosa pine	41.6	8.7	9.4	23.2	50.7	2,858
Fir-spruce	100.5	21.2	36.5	38.2	62.1	1,361
Hemlock-Sitka spruce	89.0	18.7	25.4	38.9	116.3	624
Larch	85.9	17.9	11.6	36.3	45.1	137
Lodgepole pine	42.2	8.8	9.2	22.6	52.0	1,047
Hardwoods	59.9	11.4	9.4	28.8	68.3	190
Pinyon-juniper	39.4	8.0	4.6	21.1	46.9	1,049
Minor types and nonstocked	34.5	7.0	7.3	25.1	77.0	301
Pacific Southwest						
(CA)						
Douglas-fir	118.1	24.7	14.6	37.3	40.1	366
Ponderosa pine	77.1	15.8	17.8	23.3	41.3	2,823
Fir-spruce	117.0	24.7	43.0	38.6	51.9	870
Lodgepole pine	95.4	19.7	22.2	27.3	35.2	401
Redwood	131.4	27.3	19.0	58.2	53.8	371
Hardwoods	77.7	14.8	11.1	31.0	27.0	6,164
Other softwood types	110.1	22.9	25.7	39.9	49.8	2,432
Pinyon-juniper	41.0	8.2	4.5	21.1	26.3	1,135
Chaparral	60.2	11.3	7.1	17.3	25.6	870
Minor types and nonstocked	29.8	5.9	6.3	19.8	41.6	850
Rocky Mountains, North						
(ID,MT)						
Douglas-fir	70.7	14.9	18.4	36.7	38.8	5,939
Ponderosa pine	39.2	8.2	8.3	22.9	34.3	2,191
Fir-spruce	66.2	14.0	27.4	36.9	44.1	3,802
Hemlock-Sitka spruce	82.1	17.4	32.6	36.4	46.1	639
Larch	58.5	12.4	22.9	35.8	34.2	409
Lodgepole pine	55.7	11.9	17.7	23.3	37.2	3,611
Hardwoods	34.8	6.6	10.9	27.2	54.8	555
Other softwood types	47.6	10.1	14.0	39.3	31.4	622
Minor types and nonstocked	30.2	6.1	5.1	21.1	42.3	418
Rocky Mountains, South						
(AZ,CO,NM,NV,UT,WY)						
Douglas-fir	62.5	13.3	17.5	37.8	30.9	2,212
Ponderosa pine	36.5	7.7	7.6	23.4	24.1	4,271
Fir-spruce	68.2	14.5	26.7	38.4	31.5	3,984
Lodgepole pine	53.9	11.6	19.8	24.1	27.0	2,336
Hardwoods	36.1	6.8	9.3	28.3	45.3	4,828
Other softwood types	28.5	5.9	8.0	38.6	27.9	1,409
Pinyon-juniper	28.5	5.9	3.4	21.1	19.7	18,403
Minor types and nonstocked	7.2	1.2	3.9	17.5	24.1	849

Table 3-113. Net Annual Changes in Carbon Stocks (Tg C yr⁻¹) in Forest and Harvested Wood Pools, 1990-2003

Carbon Pool	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Forest	(202)	(208)	(185)	(203)	(176)	(169)	(171)	(174)	(163)	(146)	(146)	(146)	(146)	(146)
Live, aboveground	(108)	(118)	(114)	(118)	(113)	(122)	(122)	(125)	(119)	(109)	(109)	(109)	(109)	(109)
Live, belowground	(21)	(23)	(22)	(23)	(22)	(24)	(24)	(24)	(23)	(21)	(21)	(21)	(21)	(21)
Dead Wood	(20)	(20)	(20)	(21)	(20)	(14)	(13)	(14)	(14)	(12)	(12)	(12)	(12)	(12)
Litter	(18)	(18)	(15)	(20)	(14)	(8)	(9)	(9)	(8)	(7)	(7)	(7)	(7)	(7)
Soil Organic Carbon	(34)	(28)	(14)	(21)	(8)	(2)	(3)	(2)	0	3	3	3	3	3
Harvested Wood	(57)	(54)	(55)	(56)	(57)	(55)	(57)	(58)	(56)	(59)	(57)	(58)	(58)	(59)
Wood Products	(13)	(11)	(13)	(15)	(17)	(15)	(15)	(16)	(14)	(17)	(16)	(16)	(16)	(16)
Landfilled Wood	(44)	(43)	(43)	(41)	(41)	(41)	(41)	(42)	(42)	(42)	(41)	(42)	(42)	(42)
Total Net Flux	(259)	(262)	(240)	(258)	(233)	(225)	(227)	(232)	(220)	(205)	(204)	(205)	(205)	(205)

Table 3-114. Carbon Stocks (Tg C) 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	39,489	39,700	39,908	40,093	40,296	40,472	40,641	40,812	40,986	41,149	41,296	41,442	41,589	41,735	41,882
Live, aboveground	14,114	14,222	14,340	14,453	14,572	14,685	14,807	14,928	15,053	15,172	15,281	15,390	15,499	15,608	15,717
Live, belowground	2,805	2,826	2,849	2,871	2,894	2,916	2,940	2,963	2,987	3,011	3,032	3,053	3,074	3,095	3,117
Dead Wood	2,444	2,464	2,485	2,505	2,526	2,545	2,559	2,572	2,587	2,600	2,613	2,625	2,638	2,650	2,662
Litter	4,496	4,514	4,532	4,547	4,567	4,581	4,589	4,598	4,606	4,614	4,621	4,628	4,636	4,643	4,650
Soil Organic Carbon	15,640	15,674	15,702	15,716	15,737	15,745	15,747	15,750	15,752	15,752	15,749	15,745	15,742	15,738	15,735
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
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
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
Total Carbon Stock	41,414	41,673	41,934	42,175	42,433	42,667	42,891	43,119	43,351	43,570	43,775	43,979	44,184	44,389	44,594

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

This annex presents a discussion of the methodology used to calculate annual carbon (C) flux from mineral and organic soils under agricultural management, based on changes in soil organic carbon (SOC) storage. The methodology uses a modified version of the IPCC method and a Monte Carlo uncertainty analysis, with the most detailed data available for the United States. As part of this analysis, U.S.-specific reference C stocks and management factor values were derived, along with their uncertainty as represented in probability density functions (PDF). PDFs were used to estimate SOC stocks for mineral soils in 1982, 1992, and 1997, and to estimate C emissions associated with drainage of organic soils in 1992 and 1997. These years coincide with an extensive collection of activity data for agricultural land use and management in the *U.S. National Resources Inventory* (USDA-NRCS 2000). More detailed discussions of selected topics may be found in the references cited in this annex. The details of C conversion factors and step-by-step details of calculating net CO₂ flux for mineral and organic soils are given in four steps.

Step 1: Obtain Data on Climate, Soil Types, Land-Use and Land Management Activity Over Time, and Estimate Management Factors Quantifying the Effect of Management Change on Soil Organic Carbon Storage in Mineral and Organic Soils

Step 1a: Climate and Soils

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) (see Table 3-115). Six of these climate zones occur in the conterminous United States and Hawaii (Eve et al. 2001).

Table 3-115: 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.

Climate in the United States is monitored through an extensive network of National Weather Service cooperative weather stations. Other national agencies also maintain specific climate databases such as the USDA-NRCS Snotel network and the National Climatic Data Center Global Gridded Upper Air Statistics database. The Parameter-elevation Regressions on Independent Slopes (PRISM) Model has combined the 1961 through 1990 averages from each of these sources with topographic information derived from digital elevation models, generating a grid (4 km x 4 km grid cells) of temperature and precipitation estimates for the United States (Daly et al. 1994, Daly et al. 1998). Average annual precipitation and average annual temperature were derived for the 180 Major Land Resource Areas in the United States using gridded PRISM data, which was used for assigning an IPCC climate zone to each Major Land Resource Area (see Figure 3-4). Major Land Resource Areas represent geographic units with relatively similar soils, climate, water resources, and land uses (NRCS 1981).

Figure 3-4: Major Land Resource Areas by IPCC Climate Zone

Soils were classified into one of seven classes based upon texture, morphology, and ability to store organic matter (IPCC/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) (see Table 3-116). These stocks are used in conjunction with management factors to compute the change in SOC stocks that result from management and land-use activity. Probability density functions (PDF), 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 3-116: U.S. Soil Groupings Based on the IPCC Categories and Dominant Taxonomic Soil, and Reference Carbon Stocks (Metric Tons C/ha)

IPCC Inventory Soil Categories	USDA Taxonomic Soil Orders	Reference Carbon Stock in Climate Regions					
		Cold Temperate, Dry	Cold Temperate, Moist	Warm Temperate, Dry	Warm Temperate, Moist	Sub-Tropical, Dry	Sub-Tropical, Moist
High Clay Activity Mineral Soils	Vertisols, Mollisols, Inceptisols, Aridisols, and high base status Alfisols	42 (n = 133)	65 (n = 526)	37 (n = 203)	51 (n = 424)	42 (n = 26)	57 (n = 12)
Low Clay Activity Mineral Soils	Ultisols, Oxisols, acidic Alfisols, and many Entisols	45 (n = 37)	52 (n = 113)	25 (n = 86)	40 (n = 300)	39 (n = 13)	47 (n = 7)
Sandy Soils	Any soils with greater than 70 percent sand and less than 8 percent clay (often Entisols)	24 (n = 5)	40 (n = 43)	16 (n = 19)	30 (n = 102)	33 (n = 186)	50 (n = 18)
Volcanic Soils	Andisols	124 (n = 12)	114 (n = 2)	124 (n = 12)	124 (n = 12)	124 (n = 12)	128 (n = 9)
Spodic Soils	Spodosols	86 (n=20)	74 (n = 13)	86 (n=20)	107 (n = 7)	86 (n=20)	86 (n=20)
Aquic Soils	Soils with Aquic suborder	86 (n = 4)	89 (n = 161)	48 (n = 26)	51 (n = 300)	63 (n = 503)	48 (n = 12)
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 1b: Land Use and Management Activity Data

Land use and management data for 1982, 1992, and 1997 were obtained from the *1997 National Resources Inventory (NRI)* (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.

Land use information in the NRI was merged into a set of land use and management systems relevant for SOC calculations based on the IPCC method (see Table 3-117). Each NRI point was assigned to an agricultural system in 1982, 1992, and 1997 (USDA-NRCS 2000), using information on land use from that year as well as three previous years. Hence, inventory data for the years 1979 through 1982 were used to define the 1982 land use, 1989 through 1992 for the 1992 land use, and 1994 through 1997 for the 1997 land use. 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. Overall, more than 400,000 NRI points were included in the inventory calculations that had

been identified as cropland or grazing land in 1992 or 1997. Each point represents a specific land area based upon the weighted expansion factors.

Table 3-117: Land Use and Management Systems

General Land Use		IPCC Category	
Systems	Specific Management Related Systems	Mineral Soils	Organic Soils
Agricultural (Cropland and Grazing Land)			
	Irrigated Crops	High Input Cultivation	Cultivated Crops
	Continuous Row Crops	Medium Input Cultivation	Cultivated Crops
	Continuous Small Grains	Medium Input Cultivation	Cultivated Crops
	Continuous Row Crops and Small Grains	Medium Input Cultivation	Cultivated Crops
	Row Crops in Rotation with Hay and/or Pasture	High Input Cultivation	Cultivated Crops
	Small Grains in Rotation with Hay and/or Pasture	High Input Cultivation	Cultivated Crops
	Row Crops and Small Grains in Rotation with Hay and/or Pasture	High Input Cultivation	Cultivated Crops
	Vegetable Crops	Low Input Cultivation	Cultivated Crops
	Low Residue Annual Crops (e.g., Tobacco or Cotton)	Low Input Cultivation	Cultivated Crops
	Small Grains with Fallow	Low Input Cultivation	Cultivated Crops
	Row Crops and Small Grains with Fallow	Low Input Cultivation	Cultivated Crops
	Row Crops with Fallow	Low Input Cultivation	Cultivated Crops
	Miscellaneous Crop Rotations	Medium Input Cultivation	Cultivated Crops
	Continuous Rice	Improved Land ^a	Undrained
	Rice in Rotation with other crops	Improved Land ^a	Undrained
	Continuous Perennial or Horticultural Crops	Improved Land ^a	Pasture/Forest
	Continuous Hay	Uncultivated Land (General)	Pasture/Forest
	Continuous Hay with Legumes or Irrigation	Improved Land ^a	Pasture/Forest
	Conservation Reserve Program	Uncultivated Land (Set-aside)	Undrained
	Rangeland	Uncultivated Land (General)	Undrained
	Continuous Pasture	Uncultivated Land (General)	Pasture/Forest
	Continuous Pasture with Legumes or Irrigation	Improved Land ^a	Pasture/Forest
	Aquaculture ^b	Not Estimated	Not Estimated
Non-Agricultural^c			
	Forest	Uncultivated Land (General)	Pasture/Forest
	Federal	Uncultivated Land (General)	Undrained
	Water ^b	Not Estimated	Not Estimated
	Urban Land ^b	Not Estimated	Not Estimated
	Miscellaneous ^{b,d}	Not Estimated	Not Estimated

Note: These land use and management categories were derived through analysis of the 1997 National Resources Inventory data (USDA-NRCS 2000).

^a Improved land increases SOC storage above the levels found in general land-use changes.

^b Assumes no change in C stocks when converting to or from these land uses because of a lack of information about the effect of these practices on SOC storage.

^c Some non-agricultural land is included in the inventory because it was in agricultural land use in 1992 or 1997.

^d Includes a variety of land uses from roads, beaches, and marshes to mining and gravel pits.

PDFs for the NRI land use data were assumed to be multivariate normal, and they were constructed to have a mean vector equal to the vector of total areas in different land use categories for different years of inventory, and to have a covariance matrix equal to the sampling 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.

Data on tillage practices are not reported in the 1997 National Resources Inventory, but have been collected by the Conservation Technology Information Center (CTIC 1998). Each year CTIC conducts a Crop Residue Management survey to estimate the portion of cropland managed under the various tillage systems. PDFs were 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. Conservation Technology Information Center 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 (downward adjustment of total no-tillage acres reported, Towery 2001).

Manure management is also a key practice in agricultural lands, with organic amendments leading to significant increases in SOC storage. Manure production is a critical piece of information for estimating the effect of organic amendments in the United States, and these values were derived from livestock population data that were obtained from USDA publications (USDA 1994a,b; 1995a,b; 1998a,b; 1999a-e; 2000a-g; 2001a-f; 2002a-f; 2003a-f), the FAOSTAT database (FAO 2003), and Lange (2000). In addition, manure management information was needed to estimate production, which was obtained from Poe et al. (1999), Safley et al. (1992), and personal communications with agricultural experts (Anderson 2000, Deal 2000, Johnson 2000, Miller 2000, Milton 2000, Stettler 2000, Sweeten 2000, Wright 2000). Lastly, livestock weight data were needed, which were obtained from Safley (2000), USDA (1996, 1998c), and ASAE (1999), in addition to daily rates of N excretion from ASAE (1999) and USDA (1996) and information about the fraction of poultry litter used as a feed supplement from Carpenter (1992). 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). Using these data and a linear mixed-effect modeling approach, a statistical relationship was developed between manure N production and proportion of crop and grazing land amended with manure on a county-basis. A mixed modeling approach was used to derive this functional relationship in order to account for spatial dependencies in the underlying manure management data, including a county-level random effect to account for dependence between amendments in crop and grazing lands within an individual county, in addition to a state-level random effect to account for dependencies resulting from regional differences in the usage of manure for amendment purposes. Fixed effects were included in the model for manure N production, proportion of cropland in a county, and land use category (i.e., grazing or crop land). PDFs were constructed for county-level estimates from the linear mixed-effect model based on the predictions and their associated variances and covariances (Note: covariance terms allowed for the underlying correlational structure in the manure management predictions to be reflected in the Monte Carlo uncertainty analysis). The resulting proportions were used to re-classify a portion of crop and grazing lands 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 grazing systems, the estimated proportions for land amended with manure were used to re-classify a portion of nominally-managed grazing lands as improved, in addition to a portion of improved grazing lands as improved with high input. These classification approaches are consistent with the IPCC inventory methodology (IPCC/UNEP/OECD/IEA 1997, IPCC 2004)

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 nominal ± 50 percent range was used to construct the probability density functions for the uncertainty analysis.

The amount of sewage sludge nitrogen (N) produced each year, including the amount that was available for application on agricultural lands, was provided in the Agricultural Soil Management section of the Agriculture Chapter of this volume. Sewage sludge N were 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.

Step 1c: Management Factors Quantifying the Effect of Land Use and Management Change on Soil Organic Carbon Storage in Mineral and Organic soils

Management factors representative of U.S. conditions were estimated from published studies (Ogle et al. 2003, Ogle et al. in review). 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 drainage for agricultural production. 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 (see Table 3-118). 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 pastures, 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 grasslands) on improved pastures with both medium and high input (Improved pastures are identified in the *1997 National Resources Inventory* as pastures that were irrigated or seeded with legumes, in addition to those reclassified as improved with manure amendments). 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 LULUCF Good Practice Guidance (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 the LULUCF Good Practice Guidance (IPCC 2003) that were used to construct PDFs.

Table 3-118: Management Factors for the U.S. and the IPCC Default Values Associated with Impacts on Mineral Soils

	IPCC default	U.S. Factor			
		Warm Moist Climate	Warm Dry Climate	Cool Moist Climate	Cool Dry Climate
Land Use Change					
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 Lands ^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 ^c	1.1	1.1	1.1	1.1	1.1
Tillage					
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
Input					
Low (n=85)	0.9	0.94±0.01	0.94±0.01	0.94±0.01	0.94±0.01
Medium	1	1	1	1	1
High (n=22)	1.1	1.07±0.02	1.07±0.02	1.07±0.02	1.07±0.02
High w/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 aquatic soils at 1.7, but the U.S. analysis showed no significant differences between aquatic and non-aquatic soils and so a single U.S. factor was estimated for all soil types.

^c U.S.-specific factors were not estimates for land improvements, rice production, or high input w/amendment because of few studies addressing the impact of legume mixtures, irrigation, or manure applications for crop and pasture lands in the United States, or the impact of wetland rice production in the U.S. Factors provided in the LULUCF Good Practice Guidance (IPCC 2003) were used as the best estimates of these impacts given the lack of data to estimate U.S.-specific factors.

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 (Olness et al. in press, Euliss et al. in prep). A management factor was estimated assessing the difference in SOC storage between restored and unrestored wetlands enrolled in the Conservation Reserve Program (Olness et al. in press, Euliss et al. in prep, Euliss and Gleason 2002), which represents an initial increase of C in the restored soils over the first 10 years (see Table 3-119). 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. 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 (see Table 3-119).

Table 3-119: Factor Estimate for the Initial Increase in C During the First 10 Years Following Wetland Restoration of Conservation Reserve Program. (Mass Accumulation Rate Represents Additional Gains in C for mineral soils After the First 10 Years)

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 from Euliss and Gleason (2002).

C loss rates were estimated for cultivated organic soils based on subsidence studies in the United States and Canada (see Table 3-120). PDFs were constructed as normal densities based on the mean C loss rates and associated variances. Loss rates for pasture/forest were assumed to be 25 percent of the rates for cultivated croplands due to less drainage in those systems. This assumption is consistent with the IPCC default method for calculating the loss rates associated with pasture/forest management (IPCC/UNEP/OECD/IEA 1997)

Table 3-120: Carbon Loss Rates from Organic Soils Under Agricultural Management in the United States, and the IPCC Default Rates (Metric Ton C/ha-yr)

Region	Cropland		Pasture / Forest	
	IPCC	U.S. Revised	IPCC	U.S. Revised
Cold Temperate, Dry & Cold Temperate, Moist	1	11.3 ±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	14.1±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 managed pastures and forests. Consequently, estimates are 25 percent of the values for cropland, which was an assumption used for the IPCC default organic soil C losses on pasture/forest lands.

Step 2: Estimate Land-Use and Management Activity Trends for Mineral and Organic Soils

Each National Resources Inventory (NRI) point contains land-use information for the inventory year and the three previous years, which were used to assign NRI points, designated as agricultural, to a land use/management system (see Table 3-117). NRI points that were not designated under an agricultural management practice in 1992 or 1997 were eliminated from the land base. However, a limited number of points classified as non-agricultural land uses did remain in the analysis. For example, non-agricultural land uses were included if a National Resources Inventory point was cropland or grazing land in 1992 or 1997, but was a non-agricultural land in 1982. In addition, non-agricultural uses appeared in the land base if a NRI point became a non-agricultural use in 1997 after being cropland or grazing land in 1992.

Land areas were summed to evaluate trends in the activity data between 1982 and 1997 for the IPCC land use and management categories (see Table 3-121). Between 1997 and 2002, no changes were assumed to have occurred in the relative areas of the agricultural systems with the exception of additional enrollment in the Conservation Reserve Program and the amount of land amended with manure (discussed later in this document).

Table 3-121: Areas for each Land-Use and Management System Used in IPCC Method for all U.S. Land Area Categorized as an Agricultural Use in 1992 or 1997 (Million Hectares)

IPCC Land Use/Management Categories	Land Areas ^a		
	1982	1992	1997
Medium Input Cropping	87.49	77.17	78.27
High Input Cropping ^b	22.21	22.02	21.74
Low Input Cropping ^c	30.96	28.92	25.13
Rice ^d	2.71	2.13	2.22
Uncultivated Land ^e	210.04	207.77	210.26
Improved Land ^f	31.19	33.65	31.43

Conservation Reserve Program ^g	0.00	13.78	13.23
Urban, Water, Miscellaneous Non-Cropland	1.78	0.96	4.11
Totals	386.39	386.39	386.39

Note: Based on analysis of the 1997 National Resources Inventory data (USDA-NRCS 2000).

^a Values represent total agricultural land areas including mineral and organic soils.

^b Includes hay or legumes in rotation, winter cover crop, and irrigated cropland.

^c Includes fallow and low residue cropland.

^d The rice areas in this table do not match those in the Rice Cultivation section of the Agriculture chapter because here, rice areas include both fields under continuous rice production and fields under rice in rotation with other crops (e.g., a year of rice followed by a year of wheat production). Therefore, for any particular year, the rice area in this table, representing rice-dominated management systems, is greater than the area under rice production in that year. The rice areas in the Rice Cultivation section of the Agriculture chapter include only areas that are under rice production in each year.

^e Includes hayland, rangeland, pasture, forest, and federal land-use.

^f Includes pasture or hayland with legumes or irrigation and continuous perennial crops.

^g Includes set-aside land.

The trends in agricultural practices, including both mineral and organic soils, showed a decline for the area in the high, low, and medium input cropping systems between 1982 and 1997. In addition, the rice-dominated area declined slightly over this time period. A portion of the loss in cultivated cropland was due to setting-aside areas from production in the Conservation Reserve Program, and the remaining decline can be attributed mostly to increases in urban areas, land covered in water (e.g., lakes), and miscellaneous non-cropland (e.g., barren areas and roads). The amount of area in other uncultivated land uses, including pastures and rangelands, remained relatively stable across this time period.

Almost no cropland was managed using no-till in 1982 (see Table 3-122). Some land managers, however, had started using reduced tillage systems. For the most part, adoption of reduced tillage and no-till increased steadily in the late 1980s and early 1990s, and leveled off somewhat in the mid- to late- 1990s (CTIC 1998). Because adoption of these conservation tillage techniques has leveled off, adoption was assumed to remain constant between 1997 and 2001 for this analysis. Overall, conventional tillage is the dominant management practice used in U.S. croplands over the inventory period.

Table 3-122: Tillage Percentages for each Management System in U.S. Climate Zones, with Adjustments for Long-term Adoption of No-till Agriculture (Percent)

System	1982			1992			1997		
	No Till ^a	Reduced Till ^b	Conventional Till ^c	No Till ^a	Reduced Till ^b	Conventional Till ^c	No Till ^a	Reduced Till ^b	Conventional Till ^c
Sub-Tropical, Dry									
Continuous Cropping Rotations ^d	0	3	97	0	4	96	0	15	85
Rotations with Fallow ^e	0	0	100	0	2	98	0	5	95
Low Residue Agriculture ^f	0	3	97	0	4	96	0	10	90
Sub-Tropical, Moist									
Continuous Cropping Rotations	0	0	100	0	20	80	1	10	89
Rotations with Fallow	0	0	100	0	10	90	1	10	89
Low Residue Agriculture	0	3	97	0	4	96	0	5	95
Warm Temperate, Dry									
Continuous Cropping Rotations	0	0	100	0	10	90	1	15	84
Rotations with Fallow	0	3	97	0	15	85	2	20	78
Low Residue Agriculture	0	3	97	0	1	99	0	0	100
Warm Temperate, Moist									
Continuous Cropping Rotations	0	6	94	10	30	60	12	28	60
Rotations with Fallow	0	6	94	5	30	65	8	27	65
Low Residue Agriculture	0	9	91	1	10	89	2	13	85
Cold Temperate, Dry									
Continuous Cropping Rotations	0	3	97	2	25	73	8	12	80
Rotations with Fallow	0	6	94	4	25	71	12	13	75
Low Residue Agriculture	0	0	100	1	2	97	2	6	92
Cold Temperate, Moist									
Continuous Cropping Rotations	0	11	89	5	30	65	3	17	80
Rotations with Fallow	0	11	89	5	30	65	3	27	70
Low Residue Agriculture	0	0	100	1	2	97	1	7	92

^a No-till includes CTIC survey data designated as no-tillage.

^b Reduced-till includes CTIC survey data designated as ridge tillage, mulch tillage, and reduced tillage.

^c Conventional till includes CTIC survey data designated as intensive tillage and conventional tillage.

^d Medium and high input rotations (based on the IPCC categories) found in Table 3-117. CTIC survey data for corn, soybeans, and sorghum were used in this category.

^e Rotations with fallow found in Table 3-117. CTIC survey data on fallow and small grain cropland were used in this category.

^f Low input rotations found in Table 3-117, with the exception of rotations with fallow. CTIC survey data on cotton were used in this category; tillage rates are assumed to be the same for low residue crops and vegetables in rotation.

The proportion of crop and grazing lands that were amended with manure also increased over the inventory period with modest gains in five of the six climate regions (Table 3-123). In contrast to tillage, however, some crop and grazing lands were managed with manure amendments in 1982, which limited the increase in SOC storage associated with current manure application rates.

Table 3-123. Percentage of Crop and Grazing Lands that are Managed with Manure Amendments in Each Climate Zone, as Determined from the Relationship Between Manure N Production and Application.

Climate	1982			1992			1997		
	Manure N Production (Tg N)	Crop (%)	Grazing (%)	Manure N Production (Tg N)	Crop (%)	Grazing (%)	Manure N Production (Tg N)	Crop (%)	Grazing (%)
Cool Temperate Dry	0.33	2.4	0.6	0.42	2.9	0.7	0.46	3.1	0.9
Cool Temperate Moist	1.93	1.4	2.4	2.05	1.4	2.5	1.99	1.4	2.4
Warm Temperate Dry	0.62	10.7	1.2	0.81	12.7	2.2	0.89	13.2	2.7
Warm Temperate Moist	2.54	2.5	2.4	3.19	3.0	2.7	3.33	3.3	2.7
Sub-Tropical Dry	0.09	8.6	0.8	0.09	9.3	1.0	0.09	9.8	0.8
Sub-Tropical Moist	0.15	7.9	0.8	0.18	8.6	0.7	0.18	8.3	0.7

Estimates for 1992 and 1997 are based on EPA manure N production values (EPA, this volume), while the 1982 manure N production values were provided by USDA (Kellogg et al. 2000).

Organic soils are categorized into land-use systems based on drainage for purposes of estimating C 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 C, and those used for managed pasture or agroforestry, which are assumed to have less drainage and smaller losses of C. Overall, organic soils, which are cultivated for cropland production, have remained relatively stable since 1982, but the area of organic soils managed as forest or pasture has increased slightly (see Table 3-124).

Table 3-124: Land Areas for Each Organic Land Use Category (For All U.S. Land Area Categorized as Agricultural in 1992 or 1997) (Million Hectares)

IPCC Land Use Category for Organic Soils ^a	Land Areas								
	1982			1992			1997		
	Warm Temperate	Cool Temperate	Sub-Tropical	Warm Temperate	Cool Temperate	Sub-Tropical	Warm Temperate	Cool Temperate	Sub-Tropical
Undrained	0.0005	0.0337	0.1344	0.0022	0.0651	0.1241	0.0021	0.0576	0.0964
Managed Pasture and Forest (Low Drainage)	0.04541	0.3811	0.0681	0.0397	0.3913	0.0715	0.0381	0.3989	0.0819
Cultivated Cropland (High Drainage)	0.1371	0.3103	0.1852	0.1437	0.2850	0.1940	0.1447	0.2942	0.1961
Other Land Uses ²	0.0043	0.0360	0.0050	0.0018	0.0197	0.0030	0.0024	0.0104	0.0183
Total	1.34			1.34			1.34		

^a Based on Analysis of 1997 National Resources Inventory Data.

^b Table 3-118 provides information how the IPCC land use systems are classified in the land management categories for organic soils.

^c Urban, water, and miscellaneous non-cropland, are not included in the inventory calculations because they are not agricultural uses and little is known about how they affect soil C storage relative to agricultural land management.

Step 3: Estimate Soil Organic Carbon Stocks and Associated CO₂ emissions for Mineral and Organic Soils

The IPCC method is a C accounting approach that is used to estimate C stock changes and CO₂ fluxes between soils and the atmosphere based on land use and management activity (IPCC/UNEP/OECD/IEA 1997). 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 through agricultural activities as quantified by land-use change, tillage, and input factors. For this inventory, the standard approach was modified to use agricultural SOC stocks as the reference condition, rather than uncultivated soils under native vegetation. This modification was needed because soil measurements under agricultural management are much more common and easily identified in the National Soil Survey Characterization Database (NRCS 1997). Measurements of soils under native vegetation are uncommon in the major agricultural regions of the United States because most of the area has been converted into cropland.

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 cropland production (IPCC/UNEP/OECD/IEA 1997). The IPCC approach uses an emission factor to estimate annual losses of CO₂ from organic soils, rather than an explicit stock change approach.

Mineral and organic soil calculations were made for each climate by soil zone across the United States. Mineral stock values were derived for 1982, 1992, and 1997 based on the land use and management activity data in conjunction with appropriate reference C stocks, pasture management, 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 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 4: Estimate Average Annual Changes in Soil Organic Carbon Stocks and CO₂ Emissions for Mineral and 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. For this analysis, the base inventory estimate for 1990 through 1992 is the annual average of 1992 stock minus the 1982 stock. Annual average change between 1993 and 2002 is the difference between the 1997 and 1992 C stocks. Using the Monte Carlo Approach, SOC stock change for mineral soils was estimated 50,000 times between 1982 and 1992, and between 1992 and 1997. From the final distribution of 50,000 values, a 95 percent confidence interval was generated based on the simulated values at the 2.5 and 97.5 percentiles in the distribution (Ogle et al. 2003).

For organic soils, annual losses of CO₂ were estimated for 1992 and 1997 by applying the Monte Carlo approach to 1992 and 1997 land use data and the United States. Carbon loss rates estimated for organic soils in the United States relative to those identified by IPCC for the relevant climate regimes are given in Table 3-120. The results for 1992 were applied to the years 1990 through 1992, and the results for 1997 were applied to the years 1993 through 2002.

On average, mineral soils under agricultural management were sequestering about 51.8 to 50.8 Tg CO₂ Eq. annually and organic soils lost about 34.8 to 35.6 Tg CO₂ Eq. annually (see Table 3-125). Overall, U.S. agricultural soils were estimated to currently sequester approximately 15.2 Tg CO₂ Eq. Annually (without taking liming of soils into consideration), although the uncertainties are rather large, ranging from emissions of about 7.7 Tg CO₂ Eq. annually to sequestration of about 38.1 Tg CO₂ Eq. annually.

Table 3-125: Annual Change in Soil Organic Carbon for U.S. Agricultural Soils Based on the Monte Carlo Uncertainty Analysis with U.S. Factor Values, Reference Carbon Stocks, and Carbon Loss Rates (Tg CO₂ Eq.)

Soil Type	1990-1992	1993-2002
Mineral Soils		
Estimate*	(51.8)	(50.8)
Uncertainties	(30.1) to (76.3)	(32.6) to (70.4)
Organic Soils		
Estimate	34.8	35.6

Uncertainties	23.5 to 49.1	24.2 to 50.2
Total		
Estimate	(17.0)	(15.2)
Uncertainties	(44.4) to 8.8	(38.1) to 7.7

*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.

Note: The ranges are a 95 percent confidence interval from 50,000 simulations (Ogle et al. 2003).

There are three additional land use and management activities in U.S. agriculture lands that were not estimated in the base inventory for mineral soils (i.e., uncertainty analysis). 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 applications (from the Soil Management Section of the Agriculture chapter of this Inventory), and the assumption that amendments are consistent with the assimilative capacity of crops (Kellogg et al. 2000). The impact of organic amendments on SOC was calculated as 0.1 metric ton C/ha-yr for croplands, and 0.33 metric ton C/ha-yr for grazing lands, with an overall average of 0.22 metric ton C/ha-yr. These rates are based on IPCC calculations that represent the effect of converting medium input cropping systems to high input systems and on converting nominal pastures to improved lands, respectively (assuming a reference C stock of 50 metric ton C/ha-yr, which represents a mid-range value for the dominant agricultural soils in the U.S.). From 1990 through 2003, sewage sludge applications in agricultural lands increased SOC storage from 0.5 to 1.1 Tg CO₂ Eq. (see Table 3-126).

Table 3-126: Assumptions and Calculations to Estimate the Contribution to Agricultural Soil Organic Carbon from Application of Sewage Sludge to Mineral Soils

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Sewage Sludge N Applied to Agricultural Land (Mg N) ^a	77,885	87,879	98,361	109,336	119,274	129,443	132,660	134,640	136,620	142,065	147,609	151,681	155,864	160,164
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
Area covered by Available Sewage Sludge N (ha) ^c	649,042	732,324	819,673	896,197	977,657	1,061,004	1,087,377	1,103,607	1,119,836	1,164,467	1,209,910	1,243,283	1,277,578	1,312,818
Average Annual Rate of C storage (Mg C/ha/yr) ^d	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Contribution to Agricultural Land Soil C (Tg C/yr)^{e,f}	0.14	0.16	0.18	0.20	0.22	0.23	0.24	0.24	0.25	0.26	0.27	0.27	0.28	0.29
Contribution to Agricultural Land Soil C (Tg CO₂/yr)	(0.52)	(0.59)	(0.66)	(0.72)	(0.79)	(0.86)	(0.88)	(0.89)	(0.90)	(0.94)	(0.98)	(1.00)	(1.03)	(1.06)

^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 manure 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 the national average increase in C storage for crop and grazing lands that is attributed to organic matter amendments (0.10 Mg/ha/yr in cropland and 0.33 Mg/ha/yr in grazing lands, or an average of 0.22 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

The second activity, which is not included as part of the baseline inventory, is 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 2004). An average annual change in SOC of 0.5 metric ton 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 ton C/yr, which represents a mid-range value for the dominant agricultural soils in the United States). The change in enrollment generated emissions in 1998 through 2000, but with increased enrollment from 2001 to 2003, agricultural lands sequestered an additional 0.7 and 1.1 Tg CO₂ Eq. in 2002 and 2003, respectively, relative to the baseline inventory (see Table 3-128).

Similar to CRP enrollment, the third activity was to estimate the impact of changing manure N management after 1997. Manure N production declined in each year following 1997, reaching a net reduction of 187,255 metric tons N in 2003 (Table 3-127). Using the average change in SOC storage associated with organic amendments of 0.22 metric ton C/ha-yr, manure management after 1997 has led to a decline in SOC storage of 0.31 to 1.21 Tg CO₂ Eq.

Table 3-127. Additional Change in Soil C Due to Manure Amendments After 1997.

	1998	1999	2000	2001	2002	2003
Additional Manure N (Mg N)	-48,264	-97,403	-12,1096	-12,8483	-13,7834	-18,7250
Amended Area with Available N based on Assimilative Capacity (ha) ¹	-395,608	-798,386	-992,591	-1,053,146	-1,129,788	-1,534,840
Average Annual C storage (Mg/ha/yr) ²	0.215	0.215	0.215	0.215	0.215	0.215
Soil C Flux (Tg C)	0.09	0.17	0.21	0.23	0.24	0.33
Soil C Flux (Tg CO₂ Eq.)	0.31	0.63	0.78	0.83	0.89	1.21

¹Assimilative 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).

The sum total of the base inventory and the additional land use and management considerations (i.e., sewage sludge amendments, in addition to Conservation Reserve Program enrollment and manure management from 1998 through 2003) are presented in Table 3-128. Agricultural soils, both organic and mineral, were estimated to sequester from 13.4 to 17.5 Tg CO₂ Eq. annually between 1990 and 2003, based on the change in SOC storage.

Table 3-128: Annual Net Flux of CO₂ from U.S. Agricultural Soils for the Baseline Inventory (Uncertainty Analysis) Plus the Additional Land Use/Management Considerations (Tg CO₂ Eq)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Net emissions based on uncertainty analysis	(17.02)	(17.02)	(17.02)	(15.20)	(15.20)	(15.20)	(15.20)	(15.20)	(15.20)	(15.20)	(15.20)	(15.20)	(15.20)	(15.20)
Mineral Soils	(51.85)	(51.85)	(51.85)	(50.77)	(50.77)	(50.77)	(50.77)	(50.77)	(50.77)	(50.77)	(50.77)	(50.77)	(50.77)	(50.77)
Organic Soils	34.83	34.83	34.83	35.57	35.57	35.57	35.57	35.57	35.57	35.57	35.57	35.57	35.57	35.57
Additional changes in net emissions from mineral soils	(0.52)	(0.59)	(0.66)	(0.72)	(0.79)	(0.86)	(0.88)	(0.89)	1.31	1.82	0.75	(0.84)	(1.08)	(0.93)
Sewage Sludge Applications	(0.52)	(0.59)	(0.66)	(0.72)	(0.79)	(0.86)	(0.88)	(0.89)	(0.90)	(0.94)	(0.98)	(1.00)	(1.03)	(1.06)
Manure Applications	-	-	-	-	-	-	-	-	0.31	0.63	0.78	0.83	0.89	1.21
Changes in CRP Enrollment	-	-	-	-	-	-	-	-	1.91	2.13	0.94	(0.66)	(0.94)	(1.08)
Total net emissions	(17.5)	(17.6)	(17.7)	(15.9)	(16.0)	(16.1)	(16.1)	(16.1)	(13.9)	(13.4)	(14.5)	(16.0)	(16.3)	(16.1)

Regionally, the total net annual CO₂ flux varies among Major Land Resource Areas (MLRA), and these patterns can be represented on a per hectare basis (Figure 3- 5, Figure 3- 6, Figure 3- 7, Figure 3- 8), as well as a total flux basis (see Figures 7-1, 7-2, 7-3, and 7-4). For mineral soil, most fluxes are negative due to increasing SOC storage. 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. In contrast, total fluxes were dominated by agricultural management in southeastern states and the central portion of the country where the majority of agricultural land occurs. For organic soils, all fluxes were positive leading to a net emission to the atmosphere. Similar to mineral soils, however, total fluxes were highest in the regions which contain the majority of the organic soils used for agricultural management, including the southeastern Coastal

Region, central and northern portions of the Pacific Coast, and Great Lakes Region. On a per hectare basis, the flux patterns were very similar to the total fluxes from MRLAs, with the highest rates in those regions with warmer climates and a larger proportion of the organic soil managed for crop production.

Figure 3- 5: Total Net Annual CO₂ Flux From Mineral Soils Under Agricultural Management, 1990-1992.

Figure 3- 6: Total Net Annual CO₂ Flux From Mineral Soils Under Agricultural Management, 1993-2003.

Figure 3- 7 Total Net Annual CO₂ Flux From Organic Soils Under Agricultural Management, 1990-1992.

Figure 3- 8 Total Net Annual CO₂ Flux From Organic Soils Under Agricultural Management, 1993-2003.

3.14. Methodology for Estimating CH₄ Emissions from Landfills

Landfill gas is a mixture of substances generated when bacteria decompose the organic materials contained in municipal solid waste (MSW). By volume, MSW landfill gas is about half methane and half carbon dioxide.¹ 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 CH₄ generated within a landfill is emitted to the atmosphere. If no measures are taken to extract the methane, a portion of it will oxidize as it travels through the top layer of the landfill cover. The portion of the methane that oxidizes turns primarily to carbon dioxide (CO₂). If the CH₄ is extracted and either flared or utilized for energy, then that portion of the methane generated will also be oxidized to CO₂ during combustion. In general, landfill-related CO₂ emissions are of biogenic origin and primarily result from the decomposition, either aerobic or anaerobic, of organic matter such as food or yard wastes.²

To estimate the amount of CH₄ produced in a landfill in a given year, information is needed on the type and quantity of waste in the landfill, as well as the landfill characteristics (e.g., size, aridity, waste density). However, this information is not available for all landfills in the United States. Consequently, a methodology was developed to estimate methane generation 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 CH₄ generation rates at landfills with gas recovery systems was compiled and analyzed. The results of this analysis and the results of other researchers were used to develop an estimate of the CH₄ generation potential for use in the first order decay model. In addition, the analysis provided estimates of the CH₄ generation rate constant as a function of precipitation. The first order decay model was applied to annual waste disposal estimates for each year and for three ranges of precipitation to estimate CH₄ generation rates nationwide for the years of interest. Based on organic content in industrial landfills, CH₄ emissions from industrial landfills were estimated to be seven percent of the total CH₄ generated from MSW at landfills. Total methane emissions were estimated by adding the methane from MSW and industrial landfills, subtracting the amount recovered and used for energy or flared, and subtracting the amount oxidized in the soil. The steps taken to estimate emissions from U.S. landfills for the years 1990 through 2003 are discussed in greater detail below.

Figure 3-1 presents the CH₄ emissions process—from waste generation to emissions—in graphical format.

Step 1: Estimate Annual Quantities of Solid Waste Placed in Landfills

For 1989 to 2003, 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.³ Table 3-1 shows the 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 (assuming the same rate as for 2002) since BioCycle data were not yet available at the time this report was published. The estimate for 2003 will be updated when the BioCycle survey results become available.

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

¹ 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.

² See Box 3-3 in the Energy chapter for additional background on how biogenic emissions of landfill CO₂ are addressed in the U.S. Inventory.

³ 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).

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:

$$Q_{T,x} = k \cdot R_x \cdot L_o \cdot e^{-k(T-x)}$$

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:

$$Q_T = \sum Q_{T,x} \text{ (for x equal to initial year to year T)}$$

where,

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 $L_o = 100 m^3$ /Mg. The rate constant was found to increase with annual average precipitation; consequently, average values of k were developed for three ranges of precipitation:

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 (1998) study of 18 landfills reported a range in values of k from 0.03 to 0.06 yr^{-1} .

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:

Precipitation (inches/year)	Percent of US population in the precipitation range					
	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

The methodology used in the 2003 inventory apports 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 2003).

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 CH₄ 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 and organic content of industrial waste compared to municipal waste at the time of the EPA study, as shown in the equations below (EPA 1993):

$$\frac{8.6 \text{ MMT organic waste in industrial landfills}}{65\% \text{ organic content of MSW}} = 13.2 \text{ MMT of equivalent total MSW}$$

$$13.2 \text{ MMT} \div 190 \text{ MMT total MSW in MSW landfills} = 7\%$$

Estimates of methane generation from industrial landfills are shown in Table 3-2.

Step 4: Estimate Methane Emissions Avoided

The estimate of CH₄ emissions avoided (e.g., combusted) was based on landfill-specific data on landfill gas-to-energy (LFGTE) projects and flares.

Step 4a: Estimate Methane Emissions Avoided Through Landfill Gas-to-Energy (LFGTE) Projects

The quantity of methane 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 2004) and (2) a database compiled by EPA's Landfill Methane Outreach Program (LMOP) (EPA 2004). The EIA database included location information for landfills with LFGTE projects, estimates of methane reductions, descriptions of the projects, and information on the methodology used to determine the CH₄ reductions. Generally the CH₄ reductions for each reporting year were based on the measured amount of landfill gas collected and the percent 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 CH₄ emissions avoided due to the LFGTE project. Detailed information on the landfill name, owner or operator, city, and state were available for both the EIA and LMOP databases; consequently, it was straightforward to identify landfills that were in both databases. The EIA database was given priority because reductions were reported for each year, and landfills in the LMOP database that were also in the EIA database were dropped to avoid double counting. The combined database included 358 landfills with operational LFGTE projects.

Step 4b: Estimate Methane Emissions Avoided Through Flaring

The quantity of methane flared was based on data from the EIA database and on information provided by flaring equipment vendors. To avoid double-counting, flares associated with landfills in the EIA and LMOP databases were excluded from the flare vendor database. As with the LFGTE projects, reductions from flaring landfill gas in the EIA database were based on measuring the volume of gas collected and the percent of CH₄ in the gas. The information provided by the flare vendors included information on the number of flares, flare design flow rates, year of installation, and generally the city and state location of the landfill. The median landfill gas flow rate provided by vendors was used to estimate CH₄ recovered from each remaining flare (i.e., for each flare not associated with a landfill in the EIA or LMOP databases). However, several vendors provided information on the size of the flare rather than the landfill gas flow rate. To estimate a median flare 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. Total CH₄ avoided through flaring from the flare vendor database was estimated by summing the estimates of CH₄ recovered by each flare for each year.

Step 4c: Reduce 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 CH₄ 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 CH₄ avoided due to flaring. EPA took this approach to be conservative in the estimates of CH₄ emissions avoided.

Step 5: Estimate Methane Oxidation

A portion of the CH₄ escaping from a landfill oxidizes to CO₂ in the top layer of the soil. The amount of oxidation depends upon the characteristics of the soil and the environment. For purposes of this analysis, it was assumed that ten percent of the CH₄ produced, minus the amount of gas recovered for flaring or LFGTE projects, was oxidized in the soil (Jensen and Papatti 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 CH₄ emissions were calculated by adding emissions from MSW and industrial waste, and subtracting methane recovered and oxidized, as shown in Table 3-117.

Table 3-129: Municipal Solid Waste (MSW) Contributing to CH₄ Emissions (Tg unless otherwise noted)

Description	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Total MSW Generated ^a	271	259	269	283	298	302	302	314	346	353	377	416	455	455
Percent of MSW Landfilled ^a	77%	76%	72%	71%	67%	63%	62%	61%	61%	60%	61%	61%	61%	61%
Total MSW Landfilled	209	197	194	201	200	190	187	192	211	212	230	254	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
MSW Contributing to Emissions ^c	6,815	7,012	7,206	7,407	7,606	7,796	7,984	8,175	8,383	8,598	8,828	9,083	9,361	9,640

^a Source: *BioCycle* (2004), adjusted for missing U.S. territories using U.S. Census Bureau (2004) 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 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.

Table 3-130: Methane Emissions from Landfills (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
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
Industrial Generation	657	668	678	688	698	706	712	720	730	741	755	773	795	817
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
Emissions Avoided	(935)	(1,070)	(1,222)	(1,414)	(1,724)	(2,193)	(2,654)	(3,202)	(3,839)	(4,238)	(4,626)	(5,140)	(5,450)	(5,545)
Landfill Gas-to-Energy	(669)	(694)	(766)	(846)	(902)	(1,110)	(1,336)	(1,652)	(2,018)	(2,287)	(2,472)	(2,738)	(2,814)	(2,946)
Flare	(266)	(377)	(456)	(568)	(823)	(1,083)	(1,317)	(1,551)	(1,821)	(1,951)	(2,154)	(2,403)	(2,635)	(2,599)
Oxidation at MSW Landfills	(846)	(847)	(846)	(842)	(825)	(789)	(752)	(708)	(660)	(635)	(616)	(590)	(591)	(612)
Oxidation at Industrial Landfills	(66)	(67)	(68)	(69)	(70)	(71)	(71)	(72)	(73)	(74)	(75)	(77)	(80)	(82)
Net Emissions	8,202	8,226	8,221	8,195	8,052	7,733	7,410	7,017	6,595	6,382	6,223	6,010	6,039	6,246

Note: Totals may not sum due to independent rounding.

Note: MSW generation in Table 3-130 represents emissions before oxidation. In other tables throughout the text, MSW generation estimates account for oxidation.

Note: Parentheses denote negative values.

Figure 3-9: 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 2003 based on BioCycle 2004.

^c Jensen and Papalti 2002 (first order decay model).

^d EIA 2004 and flare vendor database.

^e EIA 2004 and EPA (LMOP) 2004.

^f Mancinelli and McKay 1985; Czepiel et al 1996.

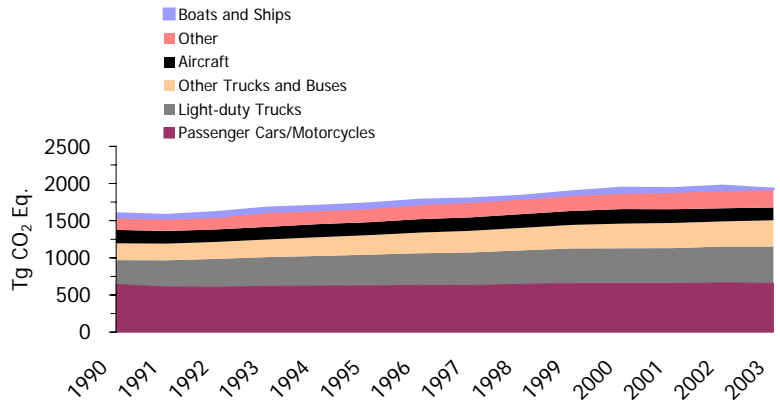


Figure 3-1: Domestic GHG Emissions by Mode and Vehicle Type

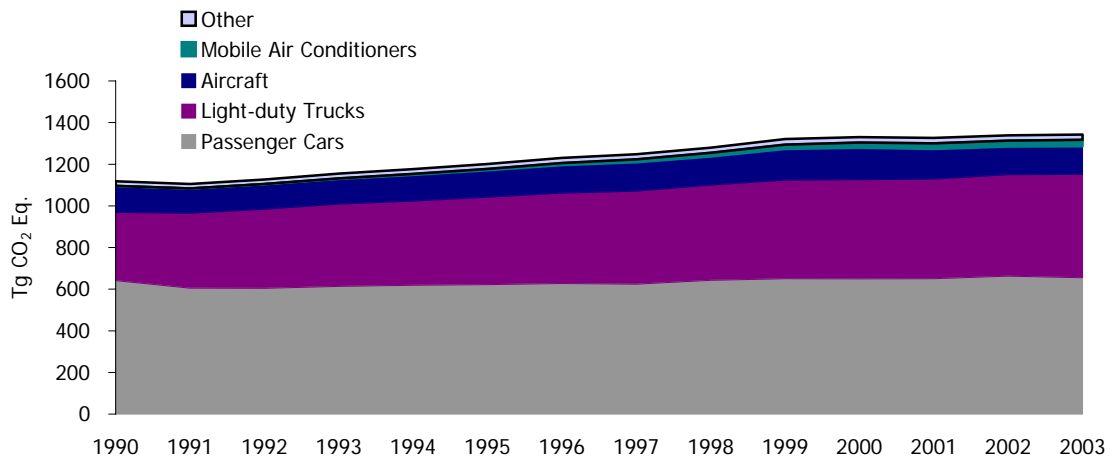


Figure 3-2: GHG Emissions from Passenger Transportation

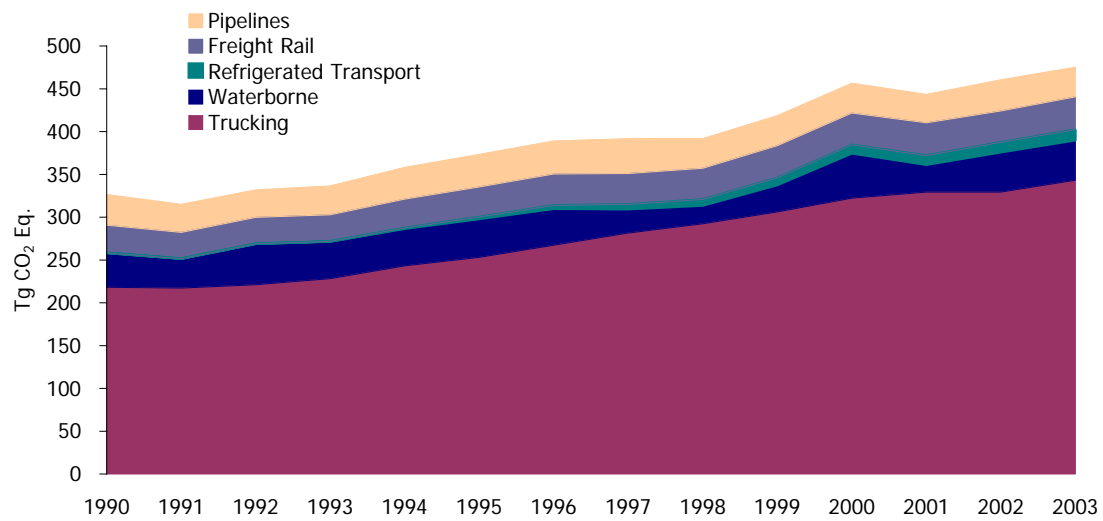


Figure 3-3: GHG Emissions from Domestic Freight Transportation

Figure 3-4

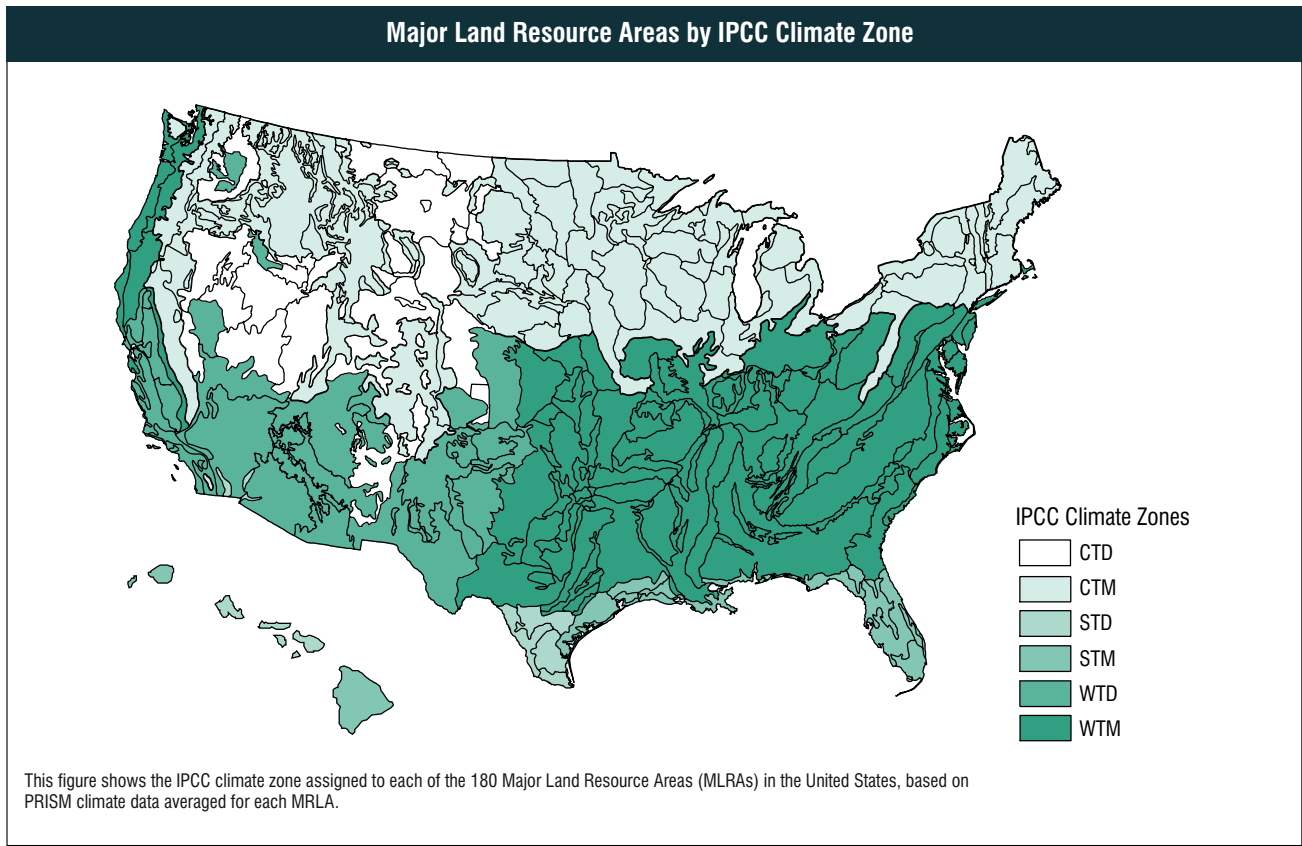
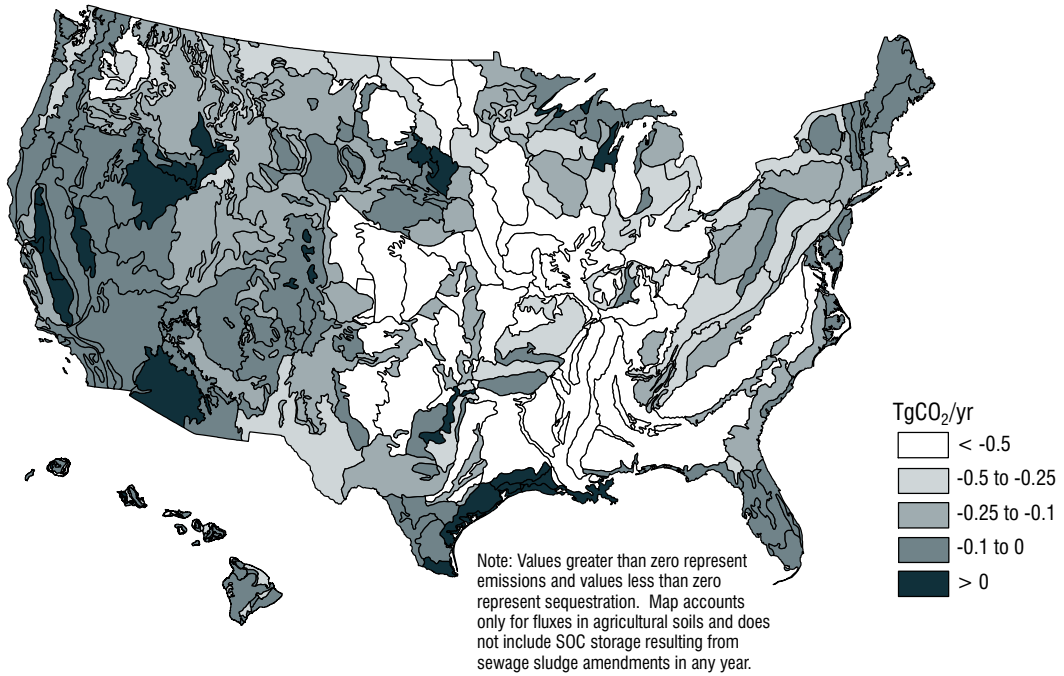


Figure 3-5

Total Net Annual CO₂ Flux From Mineral Soils Under Agricultural Management, 1990–1992



This map shows the spatial variability in total net annual carbon dioxide flux from mineral soils for the year 1990 through 1992. The color assigned to each polygon represents the total annual flux for the area of managed mineral soils in that polygon.

Figure 3-6

Total Net Annual CO₂ Flux From Mineral Soils Under Agricultural Management, 1993–2003

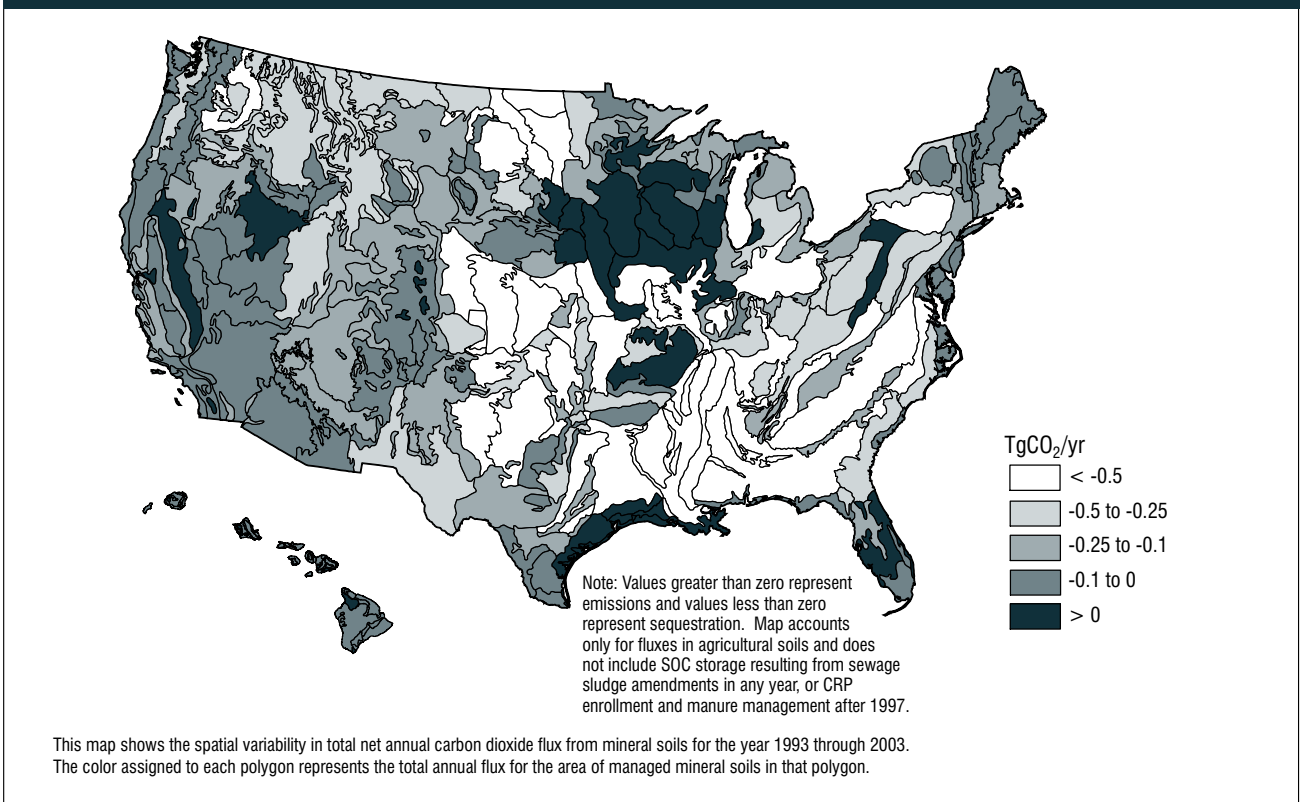


Figure 3-7

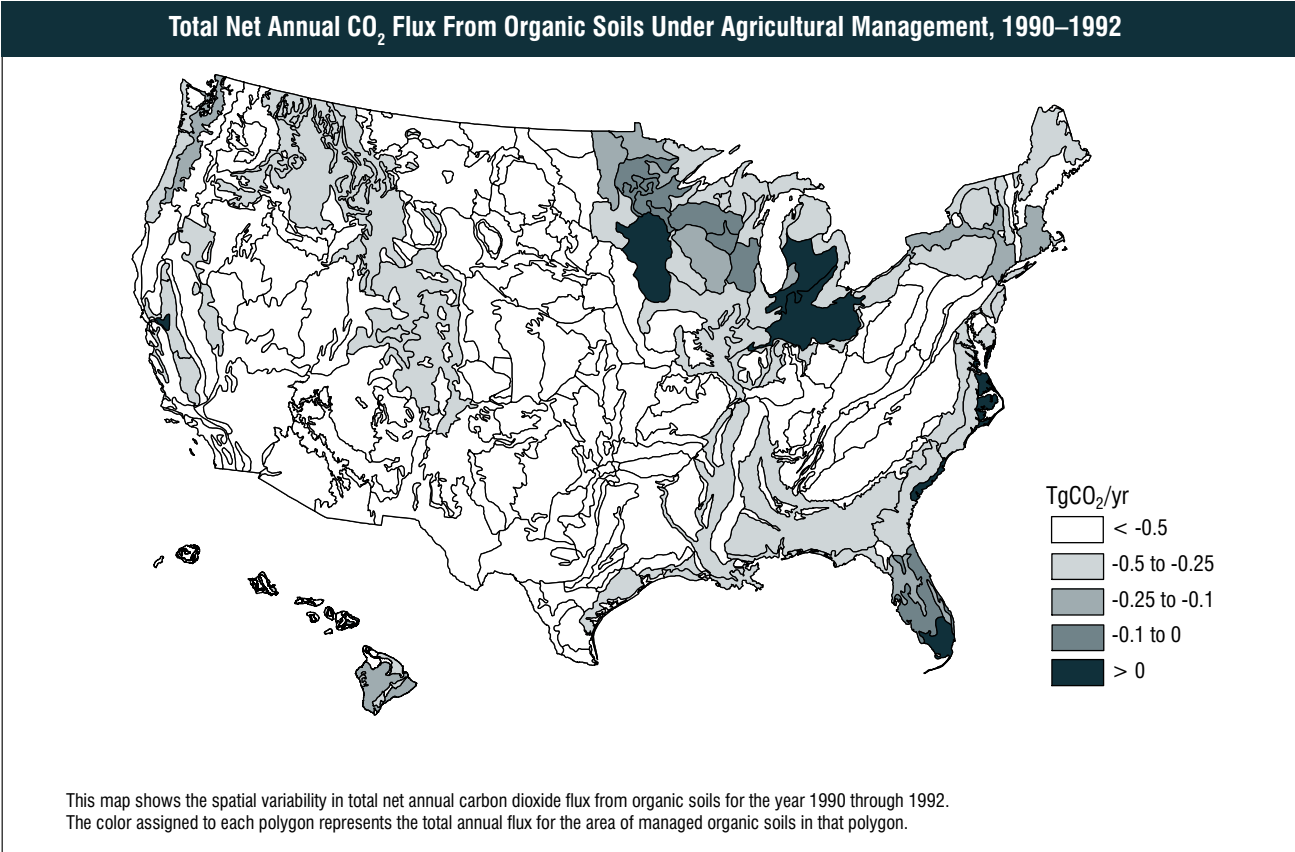


Figure 3-8

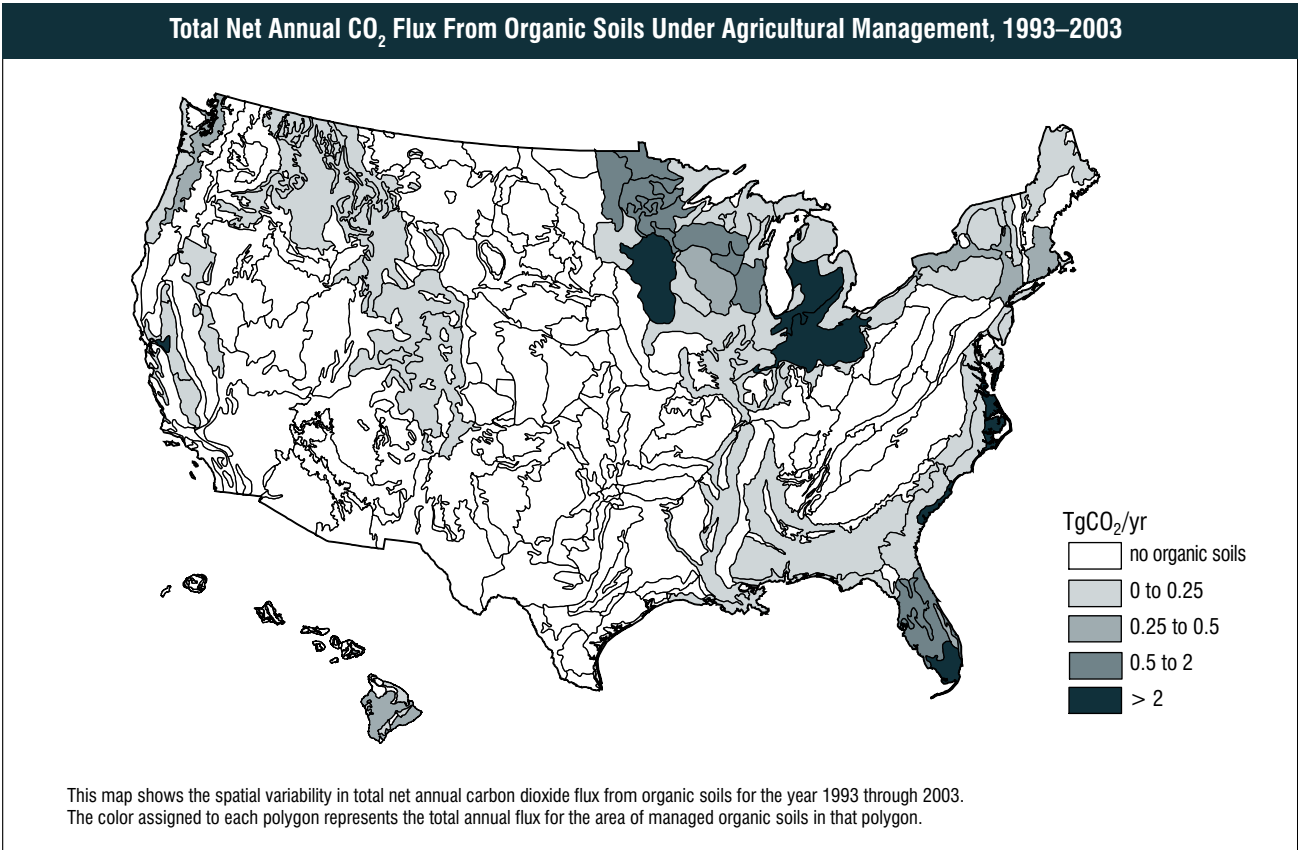
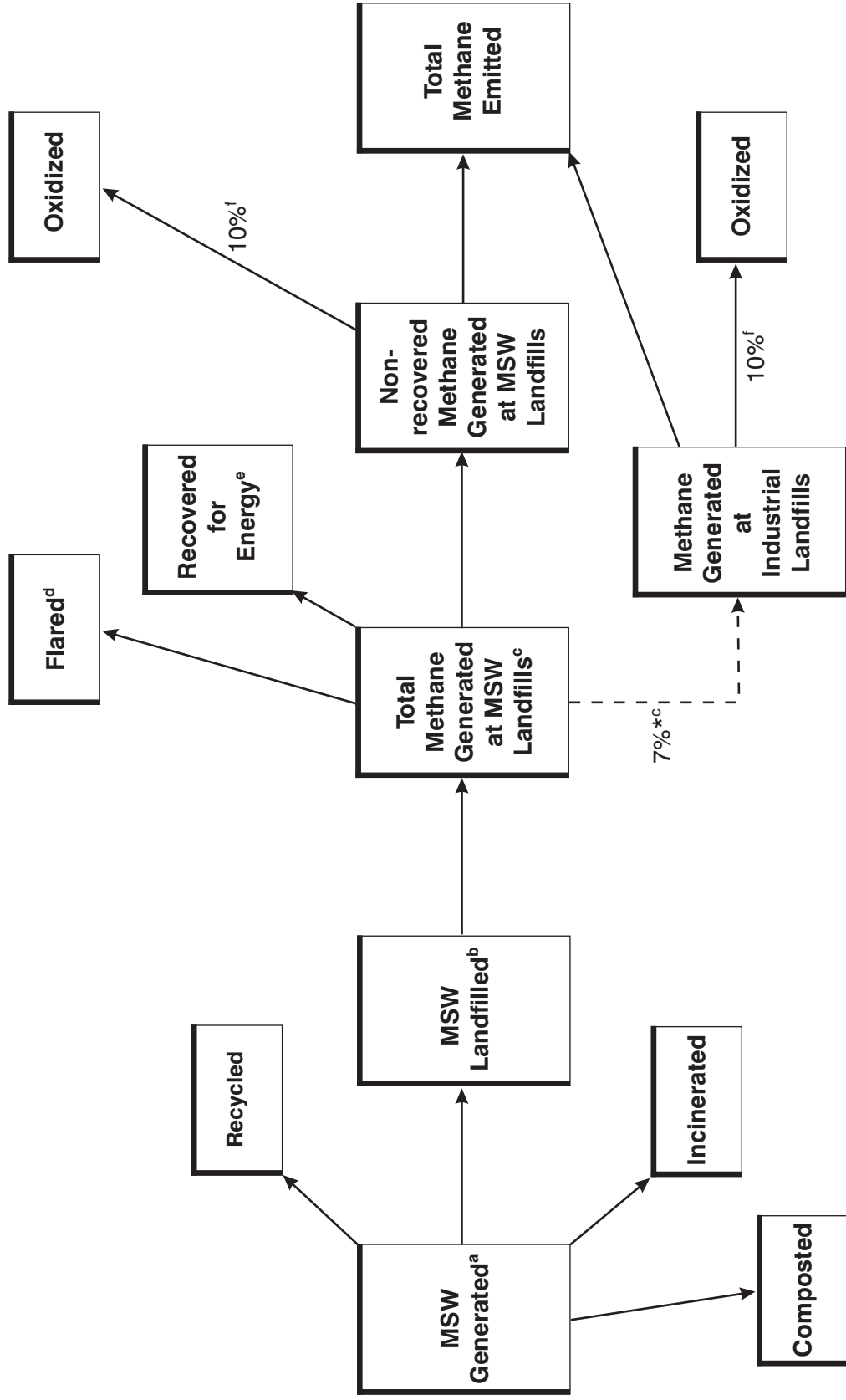


Figure 3-9: Methane Emissions Resulting from Landfilling Municipal and Industrial Waste



ANNEX 4 IPCC Reference Approach for Estimating CO₂ Emissions from Fossil Fuel Combustion

It is possible to estimate carbon dioxide (CO₂) emissions from fossil fuel consumption using alternative methodologies and different data sources than those described in 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 CO₂ emissions from fossil fuel combustion. Section 1.3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reporting Instructions* states, “If a detailed, Sectoral Approach for energy has been used for the estimation of CO₂ from fuel combustion you are still asked to complete...the Reference Approach...for verification purposes” (IPCC/UNEP/OECD/IEA 1997). This reference method estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys. The basic principle is that once 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 CO₂ emissions from fossil fuel combustion from the United States using the IPCC-recommended Reference Approach.

Step 1: Collect and Assemble Data in Proper Format

To ensure the comparability of national inventories, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention. National energy statistics were collected in physical units from several EIA documents in order to obtain the necessary data on production, imports, exports, and stock changes.

It was necessary to make a number of modifications to these data to generate more accurate apparent consumption estimates of these fuels. The first modification adjusts for consumption of fossil fuel feedstocks accounted for in the Industrial Processes chapter, which include the following: unspecified coal for coal coke used in iron and steel production; natural gas 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 CO₂ 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 4-1.

The carbon content of fuel varies with the fuel's heat content. Therefore, for an accurate estimation of CO₂ emissions, fuel statistics were provided on an energy content basis (e.g., Btu or joules). Because detailed fuel production statistics are typically provided in physical units (as in Table 4-1 for 2003), they were converted to units of energy before CO₂ emissions were calculated. Fuel statistics were converted to their energy equivalents by using conversion factors provided by EIA. These factors and their data sources are displayed in Table 4-2. The resulting fuel type-specific energy data for 2003 are provided in Table 4-3.

Step 2: Estimate Apparent Fuel Consumption

The next step of the IPCC Reference Approach is to estimate "apparent consumption" of fuels within the country. This requires a balance of primary fuels produced, plus imports, minus exports, and adjusting for stock changes. In this way, 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:

$$\text{Apparent Consumption} = \text{Production} + \text{Imports} - \text{Exports} - \text{Stock Change}$$

Flows of secondary fuels (e.g., gasoline, residual fuel, coke) should be added to primary apparent consumption. The production of secondary fuels, however, should be ignored in the calculations of apparent consumption since the 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:

$$\text{Secondary Consumption} = \text{Imports} - \text{Exports} - \text{Stock Change}$$

Note that this calculation can result in negative numbers for apparent consumption of secondary fuels. This result is perfectly acceptable since it merely indicates a net export or stock increase in the country of that fuel when domestic production is not considered.

Next, the apparent consumption and secondary consumption need to be adjusted for feedstock uses of fuels accounted for in the Industrial Processes chapter, international bunker fuels, and U.S. territory fuel consumption. Bunker fuels and feedstocks accounted for in the Industrial Processes chapter are subtracted from these estimates, while fuel consumption in U.S. territories is added.

The IPCC Reference Approach calls for estimating apparent fuel consumption before converting to a common energy unit. However, certain primary fuels in the United States (e.g., natural gas and steam coal) have separate conversion factors for production, imports, exports, and stock changes. In these cases, it is not appropriate to multiply apparent consumption by a single conversion factor since each of its components have different heat contents. Therefore, United States fuel statistics were converted to their heat equivalents before estimating apparent consumption. Results are provided in Table 4-2.

Step 3: Estimate Carbon Emissions

Once apparent consumption is estimated, the remaining calculations are similar to those for the "bottom-up" Sectoral Approach (see Annex 2.1). Potential CO₂ emissions were estimated using fuel-specific carbon coefficients (see Table 4-3).⁴ The carbon in products from non-energy uses of fossil fuels (e.g., plastics or asphalt) was then estimated and subtracted (see Table 4-4). This step differs from the Sectoral Approach in that emissions from both fuel combustion and non-energy uses are accounted for in this approach. Finally, to obtain actual CO₂ emissions, net emissions were adjusted for any carbon that remained unoxidized as a result of incomplete combustion (e.g., carbon contained in ash or soot).⁵

Step 4: Convert to CO₂ Emissions

Because the IPCC reporting guidelines recommend that countries report greenhouse gas emissions on a full molecular weight basis, the final step in estimating CO₂ emissions from fossil fuel consumption was converting from units of carbon to units of CO₂. Actual carbon emissions were multiplied by the molecular-to-atomic weight

⁴ 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 4-4 for more specific source information.

⁵ 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.

ratio of CO₂ to carbon (44/12) to obtain total carbon dioxide emitted from fossil fuel combustion in teragrams (Tg). The results are contained in Table 4-5.

Comparison Between Sectoral and Reference Approaches

These two alternative approaches can both produce reliable estimates that are comparable within a few percent. Note that the reference approach *includes* emissions from non-energy uses. Therefore, these totals should be compared to the aggregation of fuel use and emission totals from Emissions of CO₂ from Fossil Fuel Combustion (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 4-7 summarizes the differences between the Reference and Sectoral approaches in estimating total energy consumption in the United States. Although theoretically the two methods should arrive at the same estimate for U.S. energy consumption, the Reference Approach provides an energy total that is 1.4 percent higher than the Sectoral Approach for 2003. The greatest difference lies in the higher estimate of petroleum consumption with the Reference Approach (4.4 percent).

There are several potential sources for the discrepancies in consumption estimates:

- *Product Definitions.* The fuel categories in the Reference Approach are different from those used in the Sectoral Approach, particularly for petroleum. For example, the Reference Approach estimates apparent consumption for crude oil. Crude oil is not typically consumed directly, but refined into other products. As a result, the United States does not focus on estimating the energy content of the various grades of crude oil, but rather estimating the energy content of the various products resulting from crude oil refining. The United States does not believe that estimating apparent consumption for crude oil, and the resulting energy content of the crude oil, is the most reliable method for the United States to estimate its energy consumption. Other differences in product definitions include using sector-specific coal statistics in the Sectoral Approach (i.e., residential, commercial, industrial coking, industrial other, and transportation coal), while the Reference Approach characterizes coal by rank (i.e. anthracite, bituminous, etc.). Also, the liquefied petroleum gas (LPG) statistics used in the bottom-up calculations are actually a composite category composed of natural gas liquids (NGL) and LPG.
- *Heat Equivalents.* It can be difficult to obtain heat equivalents for certain fuel types, particularly for categories such as "crude oil" where the key statistics are derived from thousands of producers in the United States and abroad.
- *Possible inconsistencies in U.S. Energy Data.* The United States has not focused its energy data collection efforts on obtaining the type of aggregated information used in the Reference Approach. Rather, the United States believes that its emphasis on collection of detailed energy consumption data is a more accurate methodology for the United States to obtain reliable energy data. Therefore, top-down statistics used in the Reference Approach may not be as accurately collected as bottom-up statistics applied to the Sectoral Approach.
- *Balancing Item.* The Reference Approach uses *apparent* consumption estimates while the Sectoral Approach uses *reported* consumption estimates. While these numbers should be equal, there always seems to be a slight difference that is often accounted for in energy statistics as a "balancing item."

Differences in Estimated CO₂ Emissions

Given these differences in energy consumption data, the next step for each methodology involved estimating emissions of CO₂. Table 4-8 summarizes the differences between the two methods in estimated carbon emissions.

As mentioned above, for 2003, the Reference Approach resulted in a 1.4 percent higher estimate of energy consumption in the United States than the Sectoral Approach. The resulting emissions estimate for the Reference Approach was 1.9 percent higher. Estimates of coal and natural gas emissions using each approach yield very similar values (within 1.5 percent), though petroleum emission estimates from the Reference Approach are slightly higher (5.5 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 CO₂ emissions at the fuel level. This improvement in accuracy is largely a result of the data collection techniques used in the United States, where there has been more emphasis on obtaining the detailed products-based information used in the Sectoral Approach than obtaining the aggregated energy flow data used in the Reference Approach. The United States believes that it is valuable to understand both methods.

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Table 4-1: 2003 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	1,289	a	a	a				
	Bituminous Coal	559,169	a	a	a				
	Sub-bituminous Coal	428,443	a	a	a				
	Lignite	80,595	a	a	a				
	Coke		2,759	722	(227)				
	Unspecified Coal		25,044	43,014	(28,352)	26,770		1,775	
Gas Fuels (Million Cubic Feet)	Natural Gas	18,850,382	3,927,686	691,880	192,521	223,102		26,133	
Liquid Fuels (Thousand Barrels)	Crude Oil	2,073,453	3,527,696	4,538	30,558				
	Nat Gas Liquids and LRGs	627,510	99,015	21,390	(12,396)			1,991	
	Other Liquids	42,492	272,412	21,375	12,087				
	Motor Gasoline	112,012	189,028	45,770	(15,018)	66,685		39,956	
	Aviation Gasoline		48	0	(182)				
	Kerosene		2,285	2,645	121			171	
	Jet Fuel		39,809	7,434	(395)		149,515	18,676	
	Distillate Fuel		121,672	38,980	2,457		14,197	20,581	
	Residual Fuel		119,496	72,072	6,467		9,000	38,019	40,311
	Naphtha for petrochemical feedstocks		31,906	0	(497)				
	Petroleum Coke		8,105	131,751	1,779	13,654			
	Other Oil for petrochemical feedstocks		53,425	0	(265)	24,704			
	Special Naphthas		4,092	7,959	28				
	Lubricants		1,624	13,545	(2,154)				7
	Waxes		1,157	1,459	(169)				
	Asphalt/Road Oil		4,274	3,649	(2,031)				
	Still Gas		0	0	0				
Misc. Products			457	2,142	3			15,285	

[a] Included in Unspecified Coal

Data Sources: Solid and Gas Fuels – EIA (2004a); Liquid Fuels - EIA (1995-2004).

Table 4-2: Conversion Factors to Energy Units (Heat Equivalents)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories
Solid Fuels (Million Btu/Short Ton)	Anthracite Coal	22.57						
	Bituminous Coal	23.89						
	Sub-bituminous Coal	17.14						
	Lignite	12.87						
	Coke		24.80	24.80	24.80			
	Unspecified		25.00	25.97	20.86		25.53	25.14
Natural Gas (BTU/Cubic Foot)		1,028	1,023	1,008	1,028	1,028		1,028
Liquid Fuels (Million Btu/Barrel)	Crude Oil	5.80	5.97	5.80	5.80		5.80	5.80
	Nat Gas Liquids and LRGs	5.86	5.86	5.86	5.86		5.86	5.86
	Other Liquids	5.83	5.83	5.83	5.83		5.83	5.83
	Motor Gasoline	5.21	5.21	5.21	5.21	5.21	5.21	5.21
	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 (2004c); Unspecified Solid Fuels - EIA (2004b); Coke, Natural Gas and Petroleum Products – EIA (2004a).

Table 4-3: 2003 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	29.1							29.1	
	Bituminous Coal	13,358.6							13,358.6	
	Sub-bituminous Coal	7,343.5							7,343.5	
	Lignite	1,036.9							1,036.9	
	Coke		68.4	17.9	(5.6)				56.1	
	Unspecified			626.1	1,117.1	(591.5)	683.3	44.6	(538.3)	
Gas Fuels	Natural Gas	19,378.2	4,018.0	697.4	197.9	229.3		26.9	22,298.4	
Liquid Fuels	Crude Oil	12,026.0	21,063.9	26.3	177.2				32,886.3	
	Nat Gas Liquids and LRGs	3,676.6	580.1	125.3	(72.6)			11.7	4,215.7	
	Other Liquids	247.5	1,586.8	124.5	70.4				1,639.4	
	Motor Gasoline	583.1	984.1	238.3	(78.2)	347.2		208.0	1,268.0	
	Aviation Gasoline		0.2	0.0	(0.9)				1.2	
	Kerosene		13.0	15.0	0.7			1.0	(1.8)	
	Jet Fuel		225.7	42.2	(2.2)		847.7	105.9	(556.0)	
	Distillate Fuel			708.7	227.1	14.3		82.7	119.9	504.6
	Residual Oil			751.3	453.1	40.7	56.6	239.0	253.4	215.3
	Naphtha for petrochemical feedstocks			167.4	0.0	(2.6)				170.1
	Petroleum Coke			48.8	793.7	10.7	82.2			(837.8)
	Other Oil for petrochemical feedstocks			311.2	0.0	(1.5)	143.9			168.8
	Special Naphthas			21.5	41.8	0.1				(20.4)
	Lubricants			9.8	82.2	(13.1)				(59.2)
	Waxes			6.4	8.1	(0.9)				(0.7)
	Asphalt/Road Oil			28.4	24.2	(13.5)				17.6
Still Gas			0.0	0.0	0.0				0.0	
Misc. Products			2.6	12.4	0.0			88.6	78.8	
Total		57,679.6	31,222.6	4,046.5	(270.6)	1,542.6	1,169.5	833.1	83,274.1	

Note: Totals may not sum due to independent rounding.

Table 4-4: 2003 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	0.029	28.26	3.0
	Bituminous Coal	13.359	25.49	1,248.5
	Sub-bituminous Coal	7.344	26.48	713.0
	Lignite	1.037	26.30	100.0
	Coke	0.056	31.00	6.4
	Unspecified	(0.538)	25.34	(50.0)
Gas Fuels	Natural Gas	22.272	14.47	1,183.1
Liquid Fuels	Crude Oil	32.886	20.23	2,439.4
	Nat Gas Liquids and LRGs	4.216	16.99	262.6
	Other Liquids	1.639	20.23	121.6
	Motor Gasoline	1.268	19.34	89.9
	Aviation Gasoline	0.001	18.87	0.1
	Kerosene	(0.002)	19.72	(0.1)
	Jet Fuel	(0.556)	19.33	(39.4)
	Distillate Fuel	0.505	19.95	36.9
	Residual Oil	0.215	21.49	17.0
	Naphtha for petrochemical feedstocks	0.170	18.14	11.3
	Petroleum Coke	(0.838)	27.85	(85.6)
	Other Oil for petrochemical feedstocks	0.169	19.95	12.4
	Special Naphthas	(0.020)	19.86	(1.5)
	Lubricants	(0.059)	20.24	(4.4)
	Waxes	(0.001)	19.81	(0.1)
	Asphalt/Road Oil	0.018	20.62	1.3
Still Gas	0.000	17.51	0.0	
Misc. Products	0.079	20.23	5.8	
Total				6,071.3

Data Sources: Carbon content coefficients by coal rank from USGS (1998) and SAIC (2003); Unspecified Solid Fuels, Natural Gas and Liquid Fuels - EIA (2004a).

Note: Totals may not sum due to independent rounding.

Table 4-5: 2003 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	3.0	31.00	0.1	0.75	0.26
Natural Gas	401.0	14.47	5.8	0.65	13.85
Asphalt & Road Oil	1,217.4	20.62	25.1	1.00	92.04
LPG	1,478.4	16.84	24.9	0.65	59.42
Lubricants	312.6	20.24	6.3	0.09	2.14
Pentanes Plus	162.4	18.24	3.0	0.65	7.07
Petrochemical Feedstocks	a	a	a	a	56.99
Petroleum Coke	90.9	27.85	2.5	0.50	4.64
Special Naphtha	77.5	19.86	1.5	0.65	3.67
Waxes/Misc.	a	a	a	a	1.73
Misc. U.S. Territories Petroleum	a	a	a	a	0.65
Total					242.5

[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 4-6: 2003 Reference Approach CO₂ Emissions from Fossil Fuel Consumption (Tg CO₂ Eq. unless otherwise noted)

Fuel Category	Potential Emissions	Carbon Sequestered	Net Emissions	Fraction Oxidized	Total Emissions
Coal	2,020.9	0.3	2,020.7	99.0%	2,000.5
Petroleum	2,867.2	228.4	2,638.9	99.0%	2,612.5
Natural Gas	1,183.1	13.8	1,169.2	99.5%	1,163.4
Total	6,071.3	242.5	5,828.8	-	5,776.3

Note: Totals may not sum due to independent rounding.

Table 4-7: Fuel Consumption in the United States by Estimating Approach (Tbtu)

Approach	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Sectoral	69,724.0	69,383.1	70,929.0	72,515.8	73,925.5	74,837.8	77,383.1	78,397.5	78,748.2	80,026.3	82,418.5	80,846.3	81,825.0	82,148.4
Coal	18,063.6	18,015.6	18,186.3	18,914.4	19,000.4	19,156.1	20,077.3	20,574.8	20,737.5	20,747.8	21,692.3	20,992.2	21,123.1	21,554.9
Natural Gas	19,367.0	19,766.0	20,440.9	20,978.1	21,452.7	22,401.1	22,802.8	22,934.5	22,536.6	22,621.4	23,577.3	22,640.3	23,397.5	22,569.3
Petroleum	32,293.4	31,601.5	32,301.8	32,623.3	33,472.4	33,280.6	34,503.0	34,888.1	35,474.1	36,657.1	37,149.0	37,213.9	37,304.4	38,024.2
Reference (Apparent)	69,902.6	68,422.5	69,971.4	71,612.0	73,235.0	74,071.2	76,591.1	78,091.9	78,121.9	79,348.9	81,558.0	80,988.6	83,207.5	83,247.3
Coal	18,381.0	17,472.1	17,787.8	18,310.0	18,762.3	18,571.8	19,539.3	20,253.6	20,078.5	20,187.3	20,931.3	21,042.3	20,871.2	21,285.9
Natural Gas	19,772.2	19,786.7	20,456.3	20,990.9	21,464.6	22,417.6	22,819.7	22,954.8	22,534.5	22,639.9	23,598.4	22,661.9	23,393.2	22,298.4
Petroleum	31,749.4	31,163.7	31,727.3	32,311.1	33,008.0	33,081.8	34,232.1	34,883.5	35,509.0	36,521.8	37,041.0	37,307.3	38,966.0	39,689.8
Difference	0.3%	-1.4%	-1.4%	-1.2%	-0.9%	-1.0%	-1.0%	-0.4%	-0.8%	-0.8%	-1.0%	0.2%	1.7%	1.4%
Coal	1.8%	-3.0%	-2.2%	-3.2%	-1.3%	-3.0%	-2.7%	-1.6%	-3.2%	-2.7%	-3.5%	0.2%	-1.2%	-1.2%
Natural Gas	2.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	+	0.1%	0.1%	0.1%	+	-1.2%
Petroleum	-1.7%	-1.4%	-1.8%	-1.0%	-1.4%	-0.6%	-0.8%	+	0.1%	-0.4%	-0.3%	0.3%	4.5%	4.4%

* 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 4-8: CO₂ Emissions from Fossil Fuel Combustion by Estimating Approach (Tg CO₂ Eq.)

Approach	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Sectoral	4,819.3	4,789.0	4,881.1	4,997.4	5,080.6	5,124.3	5,308.6	5,383.1	5,413.7	5,487.1	5,669.4	5,567.7	5,619.9	5,669.2
Coal	1,681.8	1,678.5	1,694.1	1,762.5	1,771.7	1,787.9	1,873.9	1,921.4	1,937.3	1,938.8	2,026.5	1,960.3	1,973.7	2,014.3
Natural Gas	1,014.7	1,036.0	1,072.2	1,099.7	1,123.1	1,172.9	1,193.6	1,200.3	1,177.9	1,181.7	1,231.5	1,182.0	1,221.4	1,177.7
Petroleum	2,122.8	2,074.5	2,114.8	2,135.2	2,185.8	2,163.5	2,241.1	2,261.4	2,298.5	2,366.6	2,411.4	2,425.4	2,424.8	2,477.2
Reference (Apparent)	4,857.6	4,727.7	4,827.7	4,945.8	5,050.8	5,088.5	5,275.7	5,391.3	5,396.7	5,467.0	5,636.5	5,629.1	5,744.2	5,776.3
Coal	1,721.6	1,630.2	1,659.0	1,710.3	1,753.9	1,737.8	1,827.6	1,895.3	1,883.9	1,898.9	1,966.8	1,977.0	1,963.3	2,000.5
Natural Gas	1,036.1	1,037.1	1,073.0	1,100.4	1,123.7	1,173.7	1,194.5	1,201.3	1,177.7	1,182.7	1,232.0	1,181.9	1,219.9	1,162.0
Petroleum	2,099.9	2,060.4	2,095.8	2,135.1	2,173.3	2,176.9	2,253.6	2,294.7	2,335.1	2,385.4	2,437.1	2,469.0	2,559.8	2,612.5
Difference	0.8%	-1.3%	-1.1%	-1.0%	-0.6%	-0.7%	-0.6%	0.2%	-0.3%	-0.4%	-0.6%	1.1%	2.2%	1.9%
Coal	2.4%	-2.9%	-2.1%	-3.0%	-1.0%	-2.8%	-2.5%	-1.4%	-2.8%	-2.1%	-2.9%	0.9%	-0.5%	-0.7%
Natural Gas	2.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	+	0.1%	0.1%	0.1%	+	-1.2%
Petroleum	-1.1%	-0.7%	-0.9%	+	-0.6%	0.6%	0.6%	1.5%	1.6%	0.8%	1.1%	1.8%	5.6%	5.5%

+ 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 anthropogenic¹ 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 (CO₂) exchange (i.e., uptake or release) by oceans
- Natural forest fires²
- Methane (CH₄) 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 CO₂ by people or domesticated animals.³ 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., CO₂ 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.

CO₂ 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

¹ The term “anthropogenic,” in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

² 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.

³ Respiration of CO₂ by biological organisms is simply part of the broader global carbon cycle that also includes uptake of CO₂ by photosynthetic organisms.

uncertainty as to the fraction of coal oxidized during such burnings, these CO₂ emissions are not currently estimated. Further research would be required to develop accurate emission factors and activity data for these emissions to be estimated (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 1.112 - 1.113).

CO₂ 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 CO₂ may be effectively and permanently sequestered in the underground formations, however, the fraction of the injected CO₂ 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 CO₂ derived from natural sources and natural gas processing plants and used in EOR was approximately 12 Tg CO₂. Further research into EOR is required before the resulting CO₂ emissions can be adequately quantified (see CO₂ Consumption in the Industrial Processes Chapter).

CO₂ from Natural Gas Processing

Carbon dioxide (CO₂) 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 CO₂ that must be removed from the natural gas in order for it to meet pipeline specifications for CO₂ content. A fraction of the CO₂ 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 CO₂ is separated from natural gas at gas processing plants. CO₂ removed at gas processing plants is generally vented to the atmosphere, but several gas processing plants in Wyoming and Texas compress the CO₂ separated from natural gas and transport this CO₂ by pipeline for use in enhanced oil recovery. CO₂ 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 CO₂ produced from natural gas processing was 29.5 Tg CO₂ Eq. (29,455 Gg). There are four gas processing plants currently in operation—one in Wyoming and three in Texas—that produce CO₂ for use in enhanced oil recovery. In 2002, the amount of CO₂ produced by these facilities and used for enhanced oil recovery was 4.7 Tg CO₂ Eq. (4,696 Gg). This amount is not emitted to the atmosphere and is therefore subtracted from the total amount of CO₂ produced from natural gas to calculate the total amount of CO₂ produced from natural gas processing that is emitted to the atmosphere, which was 24.7 Tg CO₂ Eq. (24,654 Gg) in 2002. However, since these estimates have not been integrated with CH₄ from Natural Gas Systems and CO₂ from Fossil Fuel Combustion estimates to ensure that there is no double-counting, they are not yet included in national estimates.

CO₂ 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 CO₂ 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 CO₂ emissions.

CO₂ from Shale Oil Production

Oil shale is shale saturated with kerogen.⁴ 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.

CH₄ from the Production of Carbides other than Silicon Carbide

Methane (CH₄) may be emitted from the production of carbides because the petroleum coke used in the process contains volatile organic compounds, which form CH₄ 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 CH₄ 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)

CO₂ 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 CO₂ emissions are implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke in the Energy chapter. There is currently not sufficient data on coke consumption to estimate emissions from these sources explicitly. (See *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, pp. 2.20 - 2.21)

CO₂ from Graphite Consumption in Ferroalloy and Steel Production

Emissions from "graphite" "wood" or "biomass" in calculating CO₂ emissions from ferroalloy production, iron and steel production or other "Industrial Processes" included in Chapter 4 of the inventory are not explicitly calculated. It is assumed that 100% 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 possible that some non-coke carbon is used in the production of ferroalloys 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, 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 CO₂ 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.

⁴ Kerogen is fossilized insoluble organic material found in sedimentary rocks, usually shales, which can be converted to petroleum products by distillation.

N₂O from Caprolactam Production

Caprolactam is a widely used chemical intermediate, primarily to produce nylon-6. All processes for producing caprolactam involve the catalytic oxidation of ammonia, with N₂O being produced as a by-product. Caprolactam production could be a significant source of N₂O—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)

N₂O 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, N₂O 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)

CH₄ from Petroleum Coke Production

Coke production may result in CH₄ emissions. Detailed coke production statistics were not available for the purposes of estimating CH₄ 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)

CO₂ from Metal Production

Coke is used as a reducing agent in the production of some metals from their ores, including magnesium, chromium, lead, nickel, silicon, tin, and zinc. 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 CO₂ 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)

N₂O 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)

SF₆ from Aluminum Fluxing and Degassing

Occasionally, sulfur hexafluoride (SF₆) 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 SF₆ in the mixture is small and a portion of the SF₆ is decomposed in the process (Waite and Bernard 1990, Corns 1990). It has been estimated that 230 Mg of SF₆ were used by the aluminum industry in the United States and Canada (Maiss and Brenninkmeijer 1998); however, this estimate is highly uncertain.

SF₆ from Production/Leakage/Breakage of Soundproofed Double-glazed Windows

Sulfur hexafluoride (SF₆) 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.

SF₆ from Production/Leakage/Dismantling of Radar, Tracer and Night Vision Equipment

Sulfur hexafluoride (SF₆) 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.

SF₆ from Applications in Sports Shoes, Tires, and Tennis Balls

Sulfur hexafluoride (SF₆) 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.

SF₆ from Applications to Trace Leakage of Pressure Vessels and Used as a Tracer Gas in Open Air

Sulfur hexafluoride (SF₆) 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 SF₆ 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).

N₂O 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 (N₂O) 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 CO₂ Eq. of N₂O 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.⁵ Annual nitrogen excretion rates were estimated from protein intake. The recommended protein intake for an average size adult of each animal type⁶ 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.⁷ 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.⁸ 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

⁵ Pet Food Institute (1999) *Pet Incidence Trend Report*. Pet Food Institute, Washington DC.

⁶ Bright, S. (1999) Personal communication between Marco Alcaraz of ICF Consulting and Susan Bright of the Dupont Animal Clinic, Washington, DC, August 1999.

⁷ Swenson, M.J. and W.G. Reece, eds. (1993) *Duke's Physiology of Domestic Animals*. Cornell University Press. 11th Edition.

⁸ 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.

CO₂ from Non-Hazardous Industrial Waste Combustion

Waste combustion is incorporated in two sections of the energy chapter of the inventory: in the section on CO₂ 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 CO₂ emissions.

CH₄ from Land-Use Changes Including Wetlands Creation or Destruction

Wetlands are a known source of methane (CH₄) emissions. When wetlands are destroyed, CH₄ emissions may be reduced. Conversely, when wetlands are created (e.g., during the construction of hydroelectric plants), CH₄ emissions may increase. Grasslands and forestlands may also be weak sinks for CH₄ due to the presence of methanotrophic bacteria that use CH₄ as an energy source (i.e., they oxidize CH₄ to CO₂). Currently, an adequate scientific basis for estimating these emissions and sinks does not exist, and therefore further research and methodological development is required.

N₂O from Wastewater Treatment and Biological Processes

As a result of nitrification and denitrification processes, nitrous oxide (N₂O) 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 N₂O that originates from human excrement is currently estimated under the Human Sewage source category- based upon average dietary assumptions. The portion of emitted N₂O 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.

CH₄ from Large and Small Scale Composting

Methane (CH₄) 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.

CH₄ 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 (CH₄) 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 (CO₂) was chosen as this reference gas. Direct effects occur when the gas itself is a greenhouse gas. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The relationship between gigagrams (Gg) of a gas and Tg CO₂ Eq. can be expressed as follows:

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

Where:

Tg CO₂ Eq. = Teragrams of 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 6-1).

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.⁹

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. The short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, other ambient air pollutants (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO₂ 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 6-1: Global Warming Potentials (GWP) and Atmospheric Lifetimes (Years) of Gases Used in this Report

Gas	Atmospheric Lifetime	100-year GWP ^a	20-year GWP	500-year GWP
Carbon dioxide (CO ₂)	50-200	1	1	1
Methane (CH ₄) ^b	12±3	21	56	6.5
Nitrous oxide (N ₂ O)	120	310	280	170

⁹ 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-23	264	11,700	9,100	9,800
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 ₂ F ₆	10,000	9,200	6,200	14,000
C ₄ F ₁₀	2,600	7,000	4,800	10,100
C ₆ F ₁₄	3,200	7,400	5,000	10,700
SF ₆	3,200	23,900	16,300	34,900

Source: IPCC (1996)

^a GWPs used in this report are calculated over 100 year time horizon

^b The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO₂ is not included.

Table 6-2 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 6-2: Net 100-year Global Warming Potentials for Select Ozone Depleting Substances*

Gas	Direct	Net _{min}	Net _{max}
CFC-11	4,600	(600)	3,600
CFC-12	10,600	7,300	9,900
CFC-113	6,000	2,200	5,200
HCFC-22	1,700	1,400	1,700
HCFC-123	120	20	100
HCFC-124	620	480	590
HCFC-141b	700	(5)	570
HCFC-142b	2,400	1,900	2,300
CHCl ₃	140	(560)	0
CCl ₄	1,800	(3,900)	660
CH ₃ Br	5	(2,600)	(500)
Halon-1211	1,300	(24,000)	(3,600)
Halon-1301	6,900	(76,000)	(9,300)

Source: IPCC (2001)

* 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 CO₂ radiative forcing and an improved CO₂ 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 CO₂ is about 12 percent lower than that in the SAR, the GWPs of the other gases relative to CO₂ tend to be larger, taking into account revisions in lifetimes. However, there were some instances in which other variables, such as the radiative efficiency or the chemical lifetime, were altered that resulted in further increases or decreases in particular GWP values. In addition, the values for radiative forcing and lifetimes have been calculated for a variety of halocarbons, which were not presented in the SAR. 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 CO₂ using an improved calculation of the CO₂ radiative forcing, the SAR response function for a CO₂ pulse, and new values for the radiative forcing and lifetimes for a number of halocarbons.

Table 6-3 compares the lifetimes and GWPs for the SAR and TAR. As can be seen in Table 6-3, GWPs changed anywhere from a decrease of 35 percent to an increase of 49 percent.

Table 6-3: Comparison of GWPs and lifetimes used in the SAR and the TAR

Gas	Lifetime (years)		GWP (100 year)			
	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 ₂ O)	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 ₂ F ₆	10,000	10,000	9,200	11,900	2,700	29%
C ₃ F ₈	2,600	2,600	7,000	8,600	1,600	23%
C ₄ F ₁₀	2,600	2,600	7,000	8,600	1,600	23%
c-C ₄ F ₈	3,200	3,200	8,700	10,000	1,300	15%
C ₅ F ₁₂	4,100	4,100	7,500	8,900	1,400	19%
C ₆ F ₁₄	3,200	3,200	7,400	9,000	1,600	22%
Ethers and Halogenated Ethers						
CH ₃ OCH ₃	NA	0.015	NA	1	NA	NA
(CF ₃) ₂ CFOCH ₃	NA	3.4	NA	330	NA	NA
(CF ₃)CH ₂ OH	NA	0.5	NA	57	NA	NA
CF ₃ CF ₂ CH ₂ OH	NA	0.4	NA	40	NA	NA
(CF ₃) ₂ CHOH	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 ₅ CF ₃	NA	>1,000	NA	>17,500	NA	NA
c-C ₃ F 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) ₂ CHOCHF ₂	NA	3.1	NA	370	NA	NA
(CF ₃) ₂ CHOCH ₃	NA	0.25	NA	26	NA	NA
-(CF ₂) ₄ CH(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 CO₂ is not included.

^c Methane and nitrous oxide have chemical feedback systems that can alter the length of the atmospheric response, in these cases, global mean atmospheric lifetime (LT) is given first, followed by perturbation time (PT).

^d Gases whose lifetime has been determined only via indirect means or for whom there is uncertainty over the loss process.

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 2003 are 6,932.2 Tg CO₂ Eq., as compared to 6,900.2 Tg CO₂ Eq. when the GWPs from the SAR are used (a 0.5 percent difference). Table 6-4 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2003, using the GWPs from the TAR. The adjusted greenhouse gas emissions are shown for each gas in units of Tg CO₂ Eq. in Table 6-5. The correlating percent change in emissions of each gas is shown in Table 6-6. 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 6-7 summarizes the emissions and resulting change in emissions using GWPs from the SAR or the TAR for 1990 and 2003.

Table 6-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks using the TAR GWPs (Tg CO₂ Eq.)

Gas/Source	1990	1997	1998	1999	2000	2001	2002	2003
CO ₂	5,009.6	5,580.0	5,607.2	5,678.0	5,858.2	5,744.8	5,796.8	5,841.5
Fossil Fuel Combustion	4,711.7	5,263.2	5,278.7	5,345.9	5,545.1	5,448.0	5,501.4	5,551.6
Non-Energy Use of Fuels	108.0	120.3	135.4	141.6	124.7	120.1	118.8	118.0
Natural Gas Flaring	5.8	7.9	6.6	6.9	5.8	6.1	6.2	6.0
Cement Manufacture	33.3	38.3	39.2	40.0	41.2	41.4	42.9	43.0
Lime Manufacture	11.2	13.7	13.9	13.5	13.3	12.8	12.3	13.0
Limestone and Dolomite Use	5.5	7.2	7.4	8.1	6.0	5.7	5.9	4.7
Soda Ash Manufacture and Consumption	4.1	4.4	4.3	4.2	4.2	4.1	4.1	4.1
Carbon Dioxide Consumption	0.9	0.8	0.9	0.8	1.0	0.8	1.0	1.3
Waste Combustion	10.9	17.8	17.1	17.6	18.0	18.8	18.8	18.8
Titanium Dioxide Production	1.3	1.8	1.8	1.9	1.9	1.9	2.0	2.0
Aluminum Production	6.3	5.6	5.8	5.9	5.7	4.1	4.2	4.2
Iron and Steel Production	85.4	71.9	67.4	64.4	65.7	58.9	55.1	53.8

Ferroalloys	2.0	2.0	2.0	2.0	1.7	1.3	1.2	1.4
Ammonia Manufacture	19.3	20.7	21.9	20.6	19.6	16.7	18.6	15.6
Phosphoric Acid Production	1.5	1.5	1.6	1.5	1.4	1.3	1.3	1.4
Petrochemical Production	2.2	2.9	3.0	3.1	3.0	2.8	2.9	2.8
<i>Land-Use Change and Forestry (Sink)^a</i>	<i>(1,042.0)</i>	<i>(930.0)</i>	<i>(881.0)</i>	<i>(826.1)</i>	<i>(822.4)</i>	<i>(826.9)</i>	<i>(826.5)</i>	<i>(828.0)</i>
<i>International Bunker Fuels^b</i>	<i>113.5</i>	<i>109.9</i>	<i>114.6</i>	<i>105.3</i>	<i>101.4</i>	<i>97.9</i>	<i>89.5</i>	<i>84.2</i>
<i>Biomass Combustion^b</i>	<i>216.7</i>	<i>233.2</i>	<i>217.2</i>	<i>222.3</i>	<i>226.8</i>	<i>200.5</i>	<i>207.2</i>	<i>216.8</i>
CH₄	663.0	634.7	623.3	610.4	607.0	598.9	594.1	596.9
Stationary Sources	8.6	8.1	7.5	7.8	8.0	7.3	7.0	7.3
Mobile Sources	5.2	4.4	4.3	4.0	3.7	3.4	3.2	2.9
Coal Mining	89.7	68.6	68.7	64.5	61.6	60.9	57.4	58.9
Abandoned Coal Mines	6.6	8.9	7.8	8.0	8.5	7.6	7.0	7.0
Natural Gas Systems	140.6	146.4	144.3	139.5	144.6	144.4	143.1	137.9
Petroleum Systems	21.9	20.6	20.2	19.5	19.2	19.1	18.7	18.7
Petrochemical Production	1.3	1.8	1.8	1.9	1.8	1.6	1.7	1.7
Silicon Carbide Production	+	+	+	+	+	+	+	+
Iron and Steel Production	1.4	1.4	1.3	1.3	1.3	1.2	1.1	1.1
Enteric Fermentation	129.1	129.6	127.8	127.9	126.6	125.4	125.5	125.9
Manure Management	34.2	39.9	42.5	42.5	41.7	42.6	43.1	42.9
Rice Cultivation	7.8	8.2	8.7	9.1	8.2	8.4	7.5	7.6
Agricultural Residue Burning	0.8	0.8	0.9	0.8	0.9	0.8	0.8	0.9
Landfills	188.6	161.4	151.7	146.8	143.1	138.2	138.9	143.7
Wastewater Treatment	27.2	34.7	35.7	36.9	37.6	38.0	39.2	40.3
<i>International Bunker Fuels^b</i>	<i>0.2</i>	<i>0.2</i>	<i>0.2</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>
N₂O	364.7	378.4	389.3	364.9	383.8	368.4	363.3	359.7
Stationary Source	11.7	12.9	12.8	12.9	13.4	12.8	12.9	13.2
Mobile Sources	41.8	52.7	52.8	52.2	50.8	46.7	43.6	40.2
Adipic Acid	14.5	9.8	5.7	5.2	5.8	4.7	5.6	5.7
Nitric Acid	17.0	20.3	19.9	19.2	18.7	15.2	16.4	15.1
Manure Management	15.5	16.6	16.6	16.6	17.0	17.2	17.1	16.7
Agricultural Soil Management	241.6	240.6	255.7	232.4	251.9	245.5	241.2	242.1
Agricultural Residue Burning	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Human Sewage	12.4	14.0	14.3	14.7	14.9	14.9	15.0	15.2
N ₂ O Product Usage	4.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Waste Combustion	0.4	0.4	0.3	0.3	0.3	0.4	0.4	0.4
Settlements Remaining Settlements	5.3	5.8	5.9	5.9	5.7	5.5	5.8	5.8
Forest Land Remaining Forest Land	0.1	0.3	0.3	0.4	0.3	0.4	0.4	0.4
<i>International Bunker Fuels^b</i>	<i>0.9</i>	<i>0.9</i>	<i>1.0</i>	<i>0.9</i>	<i>0.9</i>	<i>0.8</i>	<i>0.8</i>	<i>0.7</i>
HFCs, PFCs, and SF₆	88.6	119.1	133.8	132.1	136.1	126.7	135.5	134.1
Substitution of Ozone Depleting Substances	0.3	45.2	55.1	63.8	72.8	81.0	89.0	97.0
Aluminum Production	17.0	10.1	8.3	8.3	8.2	3.7	4.9	3.5
HFC-22 Production ^c	35.9	30.7	41.2	31.2	30.6	20.3	20.3	12.7
Semiconductor Manufacture ^d	3.2	7.1	8.0	8.1	7.0	5.0	5.1	5.1
Electrical Transmission and Distribution ^e	27.1	20.1	15.8	15.2	14.5	14.3	13.7	13.1
Magnesium Production and Processing ^e	5.0	5.9	5.4	5.6	3.0	2.4	2.5	2.8
Total	6,125.9	6,712.2	6,753.6	6,785.4	6,985.1	6,838.8	6,889.7	6,932.2

+ Does not exceed 0.05 Tg CO₂ 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, CF₄, C₂F₆, C₃F₈, SF₆, and the addition of NF₃

^e SF₆ emitted

Note: Totals may not sum due to independent rounding.

Table 6-5: Change in U.S. Greenhouse Gas Emissions and Sinks Using TAR vs. SAR GWPs (Tg CO₂ Eq)

Gas	1990	1997	1998	1999	2000	2001	2002	2003
CO ₂	NC	NC	NC	NC	NC	NC	NC	NC
CH ₄	57.7	55.2	54.2	53.1	52.8	52.1	51.7	51.9
N ₂ O	(17.3)	(17.9)	(18.4)	(17.3)	(18.2)	(17.4)	(17.2)	(17.0)
HFCs, PFCs, and SF ₆ *	(2.7)	(2.6)	(1.9)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)
Total	37.7	34.7	33.8	33.1	31.9	31.9	31.7	31.9

NC (No change)

*Includes NF₃

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

Table 6-6: Change in U.S. Greenhouse Gas Emissions Using TAR vs. SAR GWPs (Percent)

Gas/Source	1990	1997	1998	1999	2000	2001	2002	2003
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 ₂ O	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)
HFCs, PFCs, and SF ₆	(2.9%)	(2.1%)	(1.4%)	(2.0%)	(2.0%)	(2.1%)	(2.0%)	(2.2%)
Substitution of Ozone Depleting Substances	(26.8%)	(2.7%)	(2.6%)	(3.1%)	(2.9%)	(2.7%)	(2.8%)	(2.5%)
Aluminum Production ^a	(7.2%)	(7.9%)	(7.9%)	(7.9%)	(8.1%)	(6.8%)	(6.8%)	(6.6%)
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%	11.9%	11.6%	12.7%	18.1%	16.4%
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 CF₄ and C₂F₆

^b HFC-23 emitted

^c Emissions from HFC-23, CF₄, C₂F₆, C₃F₈, SF₆, and the addition of NF₃

^d SF₆ emitted

Note: Excludes Sinks. Parentheses indicate negative values.

Table 6-7: Effects on U.S. Greenhouse Gas Emissions Using TAR vs. SAR GWPs (Tg CO₂Eq)

Gas	Trend from 1990 to 2003		Revisions to Annual Estimates	
	SAR	TAR	1990	2003
CO ₂	832.0	832.0	NC	NC
CH ₄	(60.4)	(66.1)	57.6	51.9
N ₂ O	(5.2)	(5.0)	(17.3)	(17.0)
HFCs, PFCs, and SF ₆ *	45.8	45.5	(2.7)	(2.9)
Total	812.1	806.3	37.7	31.9
Percent Change	13.3%	13.2%	0.6%	0.5%

NC (No Change)

*Includes NF₃

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 6-5 and Table 6-6. Table 6-8 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 (8.3 percent in 2003), due the predominance of CH₄ emissions in this sector. Emissions from all other sectors were comprised of mainly CO₂ or a mix of gases, which moderated the effect of the changes.

Table 6-8: Comparison of Emissions by Sector using IPCC SAR and TAR GWP Values (Tg CO₂Eq)

Sector	1990	1997	1998	1999	2000	2001	2002	2003
Energy								
SAR GWP (Used in Inventory)	5,141.7	5,712.8	5,737.7	5,802.6	5,985.3	5,877.3	5,920.7	5,963.4
TAR GWP	5,162.9	5,732.0	5,756.6	5,820.7	6,003.7	5,895.6	5,938.6	5,981.1
Difference (%)	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Industrial Processes								
SAR GWP (Used in Inventory)	299.9	327.1	334.9	329.2	332.1	304.7	315.4	308.6
TAR GWP	296.0	323.3	332.0	325.7	328.4	301.2	311.8	304.9
Difference (%)	(1.3%)	(1.1%)	(0.9%)	(1.1%)	(1.1%)	(1.1%)	(1.1%)	(1.2%)
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)	426.5	432.8	449.8	425.9	444.1	437.5	432.4	433.3
TAR GWP	429.2	436.1	452.6	429.7	446.8	440.4	435.6	436.4

Difference (%)	0.6%	0.8%	0.6%	0.9%	0.6%	0.7%	0.7%	0.7%
Land-Use Change and Forestry								
SAR GWP (Used in Inventory)	(1,036.5)	(923.6)	(874.5)	(819.5)	(816.1)	(820.7)	(820.1)	(821.6)
TAR GWP	(1,036.7)	(923.9)	(874.8)	(819.8)	(816.4)	(821.0)	(820.4)	(821.9)
Difference (%)	+	+	+	+	+	+	+	+
Waste								
SAR GWP (Used in Inventory)	210.1	193.7	186.0	183.1	180.6	176.5	178.3	183.8
TAR GWP	228.3	210.1	201.6	198.4	195.6	191.1	193.1	199.1
Difference (%)	8.7%	8.5%	8.4%	8.3%	8.3%	8.3%	8.3%	8.3%
Net Emissions (Sources and Sinks)								
SAR GWP (Used in Inventory)	5,046.1	5,747.5	5,838.8	5,926.1	6,130.8	5,980.1	6,031.6	6,072.2
TAR GWP	5,083.8	5,782.2	5,872.6	5,959.2	6,162.6	6,012.0	6,063.2	6,104.1
Difference (%)	0.7%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%

NC (No change)

+ Does not exceed 0.05 Tg CO₂ 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,¹ where it shields the earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,² 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.³ 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,⁴ 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 6-9.

Table 6-9: Emissions of Ozone Depleting Substances (Gg)

Compound	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Class I														
CFC-11	28.0	28.8	12.8	12.0	10.9	9.7	8.3	7.9	7.3	6.7	10.2	9.7	9.2	8.8

¹ 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.

² 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.

³ 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.

⁴ Older refrigeration and air-conditioning equipment, fire extinguishing systems, meter-dose inhalers, and foam products blown with CFCs/HCFCs may still contain ODS.

CFC-12	154.7	156.2	154.4	148.1	121.3	94.7	82.7	72.0	59.4	49.8	42.1	34.2	27.7	21.4
CFC-113	59.4	60.5	56.3	51.9	34.9	11.5	+	+	+	+	+	+	+	+
CFC-114	5.1	3.6	2.2	0.6	0.6	0.5	0.5	0.6	0.5	0.3	0.2	0.1	+	+
CFC-115	4.5	4.7	4.5	4.1	3.9	3.5	2.9	2.4	1.8	1.6	1.5	1.4	1.3	1.2
Carbon Tetrachloride	4.3	4.4	3.6	2.7	1.9	0.9	+	+	+	+	+	+	+	+
Methyl Chloroform	222.5	227.0	209.1	190.4	147.7	72.1	8.7	+	+	+	+	+	+	+
Halon-1211	0.4	0.4	0.5	0.5	0.6	0.5	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2
Halon-1301	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Class II														
HCFC-22	37.1	39.8	41.3	43.1	47.3	51.4	55.2	59.0	62.6	65.7	73.5	76.1	77.7	79.0
HCFC-123	+	+	0.2	0.5	0.8	1.0	1.3	1.5	1.8	2.0	2.2	2.4	2.6	2.7
HCFC-124	+	+	0.4	1.3	2.4	2.9	3.4	3.9	4.3	4.3	4.6	4.4	4.2	3.9
HCFC-141b	0.9	1.2	1.1	1.9	2.8	3.8	5.0	5.6	6.2	6.8	6.9	6.7	6.2	5.3
HCFC-142b	2.1	3.3	4.5	5.7	4.9	3.7	2.4	2.6	2.8	2.9	3.0	3.1	3.2	3.3
HCFC-225ca/cb	+	+	+	+	+	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

+ 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.

6.3. Sulfur Dioxide Emissions

Sulfur dioxide (SO₂), emitted into the atmosphere through natural and anthropogenic processes, affects the Earth's radiative budget through photochemical transformation into sulfate aerosols that can (1) scatter sunlight back to space, thereby reducing the radiation reaching the Earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., stratospheric ozone, by providing surfaces for heterogeneous chemical reactions). The overall effect of SO₂-derived aerosols on radiative forcing is believed to be negative (IPCC 1996). However, because SO₂ is short-lived and unevenly distributed through the atmosphere, its radiative forcing impacts are highly uncertain. Sulfur dioxide emissions have been provided below in Table 6-10.

The major source of SO₂ emissions in the United States is the burning of sulfur containing fuels, mainly coal. Metal smelting and other industrial processes also release significant quantities of SO₂. The largest contributor to U.S. emissions of SO₂ is electricity generation, accounting for 68 percent of total SO₂ emissions in 2003 (see Table 6-11); coal combustion accounted for approximately 92 percent of that total. The second largest source was industrial fuel combustion, which produced 7 percent of 2003 SO₂ emissions. Overall, SO₂ emissions in the United States decreased by 31 percent from 1990 to 2003. The majority of this decline came from reductions from electricity generation, primarily due to increased consumption of low sulfur coal from surface mines in western states.

Sulfur dioxide is important for reasons other than its effect on radiative forcing. It is a major contributor to the formation of urban smog and acid rain. As a contributor to urban smog, high concentrations of SO₂ can cause significant increases in acute and chronic respiratory diseases. In addition, once SO₂ is emitted, it is chemically transformed in the atmosphere and returns to earth as the primary contributor to acid deposition, or acid rain. Acid rain has been found to accelerate the decay of building materials and paints, and to cause the acidification of lakes and streams and damage trees. As a result of these harmful effects, the United States has regulated the emissions of SO₂ under the Clean Air Act. The EPA has also developed a strategy to control these emissions via four programs: (1) the National Ambient Air Quality Standards program,¹ (2) New Source Performance Standards,² (3) the New Source Review/Prevention of Significant Deterioration Program,³ and (4) the sulfur dioxide allowance program.⁴

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.

Table 6-10: SO₂ Emissions (Gg)

Sector/Source	1990	1997	1998	1999	2000	2001	2002	2003
Energy	19,629	16,104	16,196	14,932	13,796	13,404	12,917	13,432
Stationary Combustion	18,407	15,104	15,191	13,915	12,848	12,461	11,946	12,477
Mobile Combustion	793	659	665	704	632	624	631	634
Oil and Gas Activities	390	312	310	283	286	289	315	293
Waste Combustion	39	29	30	30	29	30	24	28
Industrial Processes	1,306	985	991	984	1,031	1,047	1,009	1,029
Chemical Manufacturing	269	235	237	295	307	310	298	298
Metals Processing	658	369	367	275	284	301	246	259
Storage and Transport	6	5	5	5	6	6	5	6
Other Industrial Processes	362	371	376	347	372	389	378	386
Miscellaneous*	11	5	5	61	63	40	82	80

¹ [42 U.S.C § 7409, CAA § 109]

² [42 U.S.C § 7411, CAA § 111]

³ [42 U.S.C § 7473, CAA § 163]

⁴ [42 U.S.C § 7651, CAA § 401]

Solvent Use	+		1	1	1	1	1	2	2
Degreasing	+		+	+	+	+	+	+	+
Graphic Arts	+		+	+	+	+	+	+	+
Dry Cleaning	NA		+	+	+	+	+	+	+
Surface Coating	+		+	+	+	+	+	+	+
Other Industrial	+		1	1	1	1	1	2	2
Non-industrial	NA		NA	NA	NA	NA	NA	NA	NA
Agriculture	NA		NA	NA	NA	NA	NA	NA	NA
Agricultural Burning	NA		NA	NA	NA	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	17,091	17,189	15,917	14,829	14,452	13,928	14,463

Source: Data taken from EPA (2004) 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 6-11: SO₂ Emissions from Electricity Generation (Gg)

Fuel Type	1990	1997	1998	1999	2000	2001	2002	2003
Coal	13,807	11,443	11,312	10,639	9,621	9,056	8,591	9,122
Petroleum	580	466	691	527	429	478	453	481
Natural Gas	1	5	5	151	157	181	172	182
Misc. Internal Combustion	45	51	52	54	54	55	53	56
Other	NA	4	110	45	78	74	70	74
Total	14,432	11,970	12,170	11,416	10,339	9,843	9,338	9,915

Source: Data taken from EPA (2004) 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 ₂ O, CO, NO _x , NMVOC
Mobile Combustion (excluding CO ₂)	CH ₄ , N ₂ O, CO, NO _x , NMVOC
Coal Mining	CH ₄
Abandoned Coal Mines	CH ₄
Natural Gas Systems	CH ₄
Petroleum Systems	CH ₄
Natural Gas Flaring	CO ₂
Industrial Processes	
Titanium Dioxide Production	CO ₂
Aluminum Production	CO ₂ , CF ₄ , C ₂ F ₆
Iron and Steel Production	CO ₂ , CH ₄
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
Adipic Acid	N ₂ O
Nitric Acid	N ₂ O
Substitution of Ozone Depleting Substances	HFCs, PFCs ^a
HCFC-22 Production	HFC-23
Semiconductor Manufacture	HFCs, PFCs, SF ₆ ^b
Electrical Transmission and Distributing	SF ₆
Magnesium Production and Processing	SF ₆
Solvent and Other Product Use	
N ₂ O Product Usage	CO, NO _x , NMVOC
Agriculture	
Enteric Fermentation	CH ₄
Manure Management	CH ₄ , N ₂ O
Rice Cultivation	CH ₄
Agricultural Residue Burning	N ₂ O
Agricultural Soil Management	CH ₄ , N ₂ O, CO, NO _x
Land-Use Change and Forestry	
CO ₂ Flux	CO ₂ (sink)
Settlements Remaining Settlements	CO ₂ (sink)
Forest Land Remaining Forest Land	CO ₂ (sink)
Waste	
Landfills	CH ₄
Wastewater Treatment	CH ₄
Human Sewage	N ₂ O

^a In 1999, included HFC-23, HFC-125, HFC-134a, HFC-143a, HFC-152a, HFC-227ea, HFC-236fa, HFC-4310mee, C₄F₁₀, C₆F₁₄, PFC/PFPEs

^b Included such gases as HFC-23, CF₄, C₂F₆, SF₆.

6.5. Constants, Units, and Conversions

Metric Prefixes

Although most activity data for the United States is gathered in customary U.S. units, these units are converted into metric units per international reporting guidelines. Table 6-12 provides a guide for determining the magnitude of metric units.

Table 6-12: 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 Conversions¹

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 6-13 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 6-13: Conversion Factors to Energy Units (Heat Equivalents)

Fuel Type (Units)	Factor
Solid Fuels (Million Btu/Short ton)	
Anthracite coal	22.573
Bituminous coal	23.89
Sub-bituminous coal	17.14
Lignite	12.866
Coke	24.8
Natural Gas (Btu/Cubic foot)	1,027

¹ Reference: EIA (1998a)

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) *Annual 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
BOD ₅	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
FAO	Food and Agricultural Organization
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
IENR	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
NMVOG	Non-methane volatile organic compound
NO _x	Nitrogen Oxides
NPRA	National Petroleum and Refiners Association
NRC	National Research Council
NRCS	Natural Resources Conservation Service
NRI	National Resources Inventory
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
TgCO 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 6-14: Guide to Chemical Formulas

Symbol	Name
Al	Aluminum
Al ₂ O ₃	Aluminum Oxide
Br	Bromine
C	Carbon
CH ₄	Methane
C ₂ H ₆	Ethane
C ₃ H ₈	Propane
CF ₄	Perfluoromethane
C ₂ F ₆	Perfluoroethane, hexafluoroethane
c-C ₃ F ₆	Perfluorocyclopropane
C ₃ F ₈	Perfluoropropane
c-C ₄ F ₈	Perfluorocyclobutane
C ₄ F ₁₀	Perfluorobutane
C ₅ F ₁₂	Perfluoropentane
C ₆ F ₁₄	Perfluorohexane
CF ₃ I	Trifluoroiodomethane
CFCl ₃	Trichlorofluoromethane (CFC-11)
CF ₂ Cl ₂	Dichlorodifluoromethane (CFC-12)
CF ₃ Cl	Chlorotrifluoromethane (CFC-13)
C ₂ F ₃ Cl ₃	Trichlorotrifluoroethane (CFC-113)*
CCl ₃ CF ₃	CFC-113a*
C ₂ F ₄ Cl ₂	Dichlorotetrafluoroethane (CFC-114)
C ₂ F ₅ Cl	Chloropentafluoroethane (CFC-115)
CHCl ₂ F	HCFC-21
CHF ₂ Cl	Chlorodifluoromethane (HCFC-22)
C ₂ F ₃ HCl ₂	HCFC-123
C ₂ F ₄ HCl	HCFC-124
C ₂ FH ₃ Cl ₂	HCFC-141b
C ₂ H ₃ F ₂ Cl	HCFC-142b
CF ₃ CF ₂ CHCl ₂	HCFC-225ca
CClF ₂ CF ₂ CHClF	HCFC-225cb
CCl ₄	Carbon tetrachloride
CHClCCl ₂	Trichloroethylene
CCl ₂ CCl ₂	Perchloroethylene, tetrachloroethene
CH ₃ Cl	Methylchloride
CH ₃ CCl ₃	Methylchloroform
CH ₂ Cl ₂	Methylenechloride
CHCl ₃	Chloroform, trichloromethane
CHF ₃	HFC-23
CH ₂ F ₂	HFC-32
CH ₃ F	HFC-41
C ₂ HF ₅	HFC-125
C ₂ H ₂ F ₄	HFC-134
CH ₂ FCF ₃	HFC-134a
C ₂ H ₃ F ₃	HFC-143*
C ₂ H ₃ F ₃	HFC-143a*
CH ₂ FCH ₂ F	HFC-152*
C ₂ H ₄ F ₂	HFC-152a*
CH ₃ CH ₂ F	HFC-161
C ₃ HF ₇	HFC-227ea
CF ₃ CF ₂ CH ₂ F	HFC-236cb
CF ₃ CHFCHF ₂	HFC-236ea
C ₃ H ₂ F ₆	HFC-236fa
C ₃ H ₃ F ₅	HFC-245ca
CHF ₂ CH ₂ CF ₃	HFC-245fa
CF ₃ CH ₂ CF ₂ CH ₃	HFC-365mfc
C ₅ H ₂ F ₁₀	HFC-43-10mee

CF ₃ OCHF ₂	HFE-125
CF ₂ HOCF ₂ H	HFE-134
CH ₃ OCF ₃	HFE-143a
CF ₃ CHFOCF ₃	HFE-227ea
CF ₃ CHClOCHF ₂	HCFE-235da2
CF ₃ CHFOCHF ₂	HFE-236ea2
CF ₃ CH ₂ OCF ₃	HFE-236fa
CF ₃ CF ₂ OCH ₃	HFE-245cb2
CHF ₂ CH ₂ OCF ₃	HFE-245fa1
CF ₃ CH ₂ OCHF ₂	HFE-245fa2
CHF ₂ CF ₂ OCH ₃	HFE-254cb2
CF ₃ CH ₂ OCH ₃	HFE-263fb2
CF ₃ CF ₂ OCF ₂ CHF ₂	HFE-329mcc2
CF ₃ CF ₂ OCH ₂ CF ₃	HFE-338mcf2
CF ₃ CF ₂ CF ₂ OCH ₃	HFE-347mcc3
CF ₃ CF ₂ OCH ₂ CHF ₂	HFE-347mcf2
CF ₃ CHFCF ₂ OCH ₃	HFE-356mec3
CHF ₂ CF ₂ CF ₂ OCH ₃	HFE-356pcc3
CHF ₂ CF ₂ OCH ₂ CHF ₂	HFE-356pcf2
CHF ₂ CF ₂ CH ₂ OCHF ₂	HFE-356pcf3
CF ₃ CF ₂ CH ₂ OCH ₃	HFE-365mcf3
CHF ₂ CF ₂ OCH ₂ CH ₃	HFE-374pcf2
C ₄ F ₉ OCH ₃	HFE-7100
C ₄ F ₉ OC ₂ H ₅	HFE-7200
CHF ₂ OCF ₂ OC ₂ F ₄ OCHF ₂	H-Galden 1040x
CHF ₂ OCF ₂ OCHF ₂	HG-10
CHF ₂ OCF ₂ CF ₂ OCHF ₂	HG-01
CH ₃ OCH ₃	Dimethyl ether
CH ₂ Br ₂	Dibromomethane
CH ₂ BrCl	Dibromochloromethane
CHBr ₃	Tribromomethane
CHBrF ₂	Bromodifluoromethane
CH ₃ Br	Methylbromide
CF ₂ BrCl	Bromodichloromethane (Halon 1211)
CF ₃ Br(CBrF ₃)	Bromotrifluoromethane (Halon 1301)
CF ₃ I	FIC-131I
CO	Carbon monoxide
CO ₂	Carbon dioxide
CaCO ₃	Calcium carbonate, Limestone
CaMg(CO ₃) ₂	Dolomite
CaO	Calcium oxide, Lime
Cl	atomic Chlorine
F	Fluorine
Fe	Iron
Fe ₂ O ₃	Ferric oxide
FeSi	Ferrosilicon
H, H ₂	atomic Hydrogen, molecular Hydrogen
H ₂ O	Water
H ₂ O ₂	Hydrogen peroxide
OH	Hydroxyl
N, N ₂	atomic Nitrogen, molecular Nitrogen
NH ₃	Ammonia
NH ₄ ⁺	Ammonium ion
HNO ₃	Nitric Acid
NF ₃	Nitrogen trifluoride
N ₂ O	Nitrous oxide
NO	Nitric oxide
NO ₂	Nitrogen dioxide
NO ₃	Nitrate radical
Na	Sodium
Na ₂ CO ₃	Sodium carbonate, soda ash
Na ₃ AlF ₆	Synthetic cryolite

O, O ₂	atomic Oxygen, molecular Oxygen
O ₃	Ozone
S	atomic Sulfur
H ₂ SO ₄	Sulfuric acid
SF ₆	Sulfur hexafluoride
SF ₅ CF ₃	Trifluoromethylsulphur pentafluoride
SO ₂	Sulfur dioxide
Si	Silicon
SiC	Silicon carbide
SiO ₂	Quartz

* Distinct isomers.

6.8. Glossary

Abiotic.⁷ Nonliving. Compare *biotic*.

Absorption of radiation.¹ The uptake of radiation by a solid body, liquid or gas. The absorbed energy may be transferred or re-emitted.

Acid deposition.⁶ A complex chemical and atmospheric process whereby recombined emissions of sulfur and nitrogen compounds are redeposited on earth in wet or dry form. See *acid rain*.

Acid rain.⁶ Rainwater that has an acidity content greater than the postulated natural pH of about 5.6. It is formed when sulfur dioxides and nitrogen oxides, as gases or fine particles in the atmosphere, combine with water vapor and precipitate as sulfuric acid or nitric acid in rain, snow, or fog. The dry forms are acidic gases or particulates. See *acid deposition*.

Acid solution.⁷ Any water solution that has more hydrogen ions (H⁺) than hydroxide ions (OH⁻); any water solution with a pH less than 7. See *basic solution*, *neutral solution*.

Acidic.⁷ See acid solution.

Adiabatic process.⁹ A thermodynamic change of state of a system such that no heat or mass is transferred across the boundaries of the system. In an adiabatic process, expansion always results in cooling, and compression in warming.

Aerosol.^{1&9} Particulate matter, solid or liquid, larger than a molecule but small enough to remain suspended in the atmosphere. Natural sources include salt particles from sea spray and dust and clay particles as a result of weathering of rocks, both of which are carried upward by the wind. Aerosols can also originate as a result of human activities and are often considered pollutants. Aerosols are important in the atmosphere as nuclei for the condensation of water droplets and ice crystals, as participants in various chemical cycles, and as absorbers and scatterers of solar radiation, thereby influencing the radiation budget of the Earth's climate system. See *climate*, *particulate matter*.

Afforestation.² Planting of new forests on lands that have not been recently forested.

Air carrier⁸ An operator (e.g., airline) in the commercial system of air transportation consisting of aircraft that hold certificates of, Public Convenience and Necessity, issued by the Department of Transportation, to conduct scheduled or non-scheduled flights within the country or abroad.

Air pollutant. See *air pollution*.

Air pollution.⁷ One or more chemicals or substances in high enough concentrations in the air to harm humans, other animals, vegetation, or materials. Such chemicals or physical conditions (such as excess heat or noise) are called air pollutants.

Albedo.⁹ The fraction of the total solar radiation incident on a body that is reflected by it.

Alkalinity.⁶ Having the properties of a base with a pH of more than 7. A common alkaline is baking soda.

Alternative energy.⁶ Energy derived from nontraditional sources (e.g., compressed natural gas, solar, hydroelectric, wind).

Anaerobic.⁶ A life or process that occurs in, or is not destroyed by, the absence of oxygen.

Anaerobic decomposition.² The breakdown of molecules into simpler molecules or atoms by microorganisms that can survive in the partial or complete absence of oxygen.

Anaerobic lagoon.² A liquid-based manure management system, characterized by waste residing in water to a depth of at least six feet for a period ranging between 30 and 200 days. Bacteria produce methane in the absence of oxygen while breaking down waste.

Anaerobic organism.⁷ Organism that does not need oxygen to stay alive. See *aerobic organism*.

Antarctic "Ozone Hole."⁶ Refers to the seasonal depletion of stratospheric ozone in a large area over Antarctica. See *ozone layer*.

Anthracite.² A hard, black, lustrous coal containing a high percentage of fixed carbon and a low percentage of volatile matter. Often referred to as hard coal.

Anthropogenic.² Human made. In the context of greenhouse gases, emissions that are produced as the result of human activities.

Arable land.⁷ Land that can be cultivated to grow crops.

Aromatic.⁶ Applied to a group of hydrocarbons and their derivatives characterized by the presence of the benzene ring.

Ash.⁶ The mineral content of a product remaining after complete combustion.

Asphalt.² A dark-brown-to-black cement-like material containing bitumen as the predominant constituent. It is obtained by petroleum processing. The definition includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalt.

Atmosphere.¹ The mixture of gases surrounding the Earth. The Earth's atmosphere consists of about 79.1 percent nitrogen (by volume), 20.9 percent oxygen, 0.036 percent carbon dioxide and trace amounts of other gases. The atmosphere can be divided into a number of layers according to its mixing or chemical characteristics, generally determined by its thermal properties (temperature). The layer nearest the Earth is the *troposphere*, which reaches up to an altitude of about 8 kilometers (about 5 miles) in the polar regions and up to 17 kilometers (nearly 11 miles) above the equator. The *stratosphere*, which reaches to an altitude of about 50 kilometers (31 miles) lies atop the troposphere. The *mesosphere*, which extends from 80 to 90 kilometers atop the stratosphere, and finally, the *thermosphere*, or *ionosphere*, gradually diminishes and forms a fuzzy border with outer space. There is relatively little mixing of gases between layers.

Atmospheric lifetime. See *lifetime*.

Atomic weight.⁶ The average weight (or mass) of all the isotopes of an element, as determined from the proportions in which they are present in a given element, compared with the mass of the 12 isotope of carbon (taken as precisely 12.000), that is the official international standard; measured in daltons.

Atoms.⁷ Minute particles that are the basic building blocks of all chemical elements and thus all matter.

Aviation Gasoline.⁸ All special grades of gasoline for use in aviation reciprocating engines, as given in the American Society for Testing and Materials (ASTM) specification D 910. Includes all refinery products within the gasoline range that are to be marketed straight or in blends as aviation gasoline without further processing (any refinery operation except mechanical blending). Also included are finished components in the gasoline range, which will be used for blending or compounding into aviation gasoline.

Bacteria.⁷ One-celled organisms. Many act as decomposers that break down dead organic matter into substances that dissolve in water and are used as nutrients by plants.

Barrel (bbl).⁶ A liquid-volume measure equal to 42 United States gallons at 60 degrees Fahrenheit; used in expressing quantities of petroleum-based products.

Basic solution.⁷ Water solution with more hydroxide ions (OH⁻) than hydrogen ions (H⁺); water solutions with pH greater than 7. See *acid solution*, *alkalinity*, *acid*.

Biodegradable.⁷ Material that can be broken down into simpler substances (elements and compounds) by bacteria or other decomposers. Paper and most organic wastes such as animal manure are biodegradable. See *nonbiodegradable*.

Biofuel.^{3&7} Gas or liquid fuel made from plant material (biomass). Includes wood, wood waste, wood liquors, peat, railroad ties, wood sludge, spent sulfite liquors, agricultural waste, straw, tires, fish oils, tall oil, sludge waste, waste alcohol, municipal solid waste, landfill gases, other waste, and ethanol blended into motor gasoline.

Biogeochemical cycle.⁷ Natural processes that recycle nutrients in various chemical forms from the environment, to organisms, and then back to the environment. Examples are the carbon, oxygen, nitrogen, phosphorus, and hydrologic cycles.

Biological oxygen demand (BOD).⁷ Amount of dissolved oxygen needed by aerobic decomposers to break down the organic materials in a given volume of water at a certain temperature over a specified time period. See *BOD₅*.

Biomass.⁷ Total dry weight of all living organisms that can be supported at each trophic level in a food chain. Also, materials that are biological in origin, including organic material (both living and dead) from above and below ground, for example, trees, crops, grasses, tree litter, roots, and animals and animal waste.

Biomass energy.¹ Energy produced by combusting biomass materials such as wood. The carbon dioxide emitted from burning biomass will not increase total atmospheric carbon dioxide if this consumption is done on a sustainable basis (i.e., if in a given period of time, regrowth of biomass takes up as much carbon dioxide as is released from biomass combustion). Biomass energy is often suggested as a replacement for fossil fuel combustion.

Biosphere.^{2&7} The living and dead organisms found near the earth's surface in parts of the lithosphere, atmosphere, and hydrosphere. The part of the global carbon cycle that includes living organisms and biogenic organic matter.

Biotic.⁷ Living. Living organisms make up the biotic parts of ecosystems. See *abiotic*.

Bitumen.⁷ Goopy, black, high-sulfur, heavy oil extracted from tar sand and then upgraded to synthetic fuel oil. See *tar sand*.

Bituminous coal.² A dense, black, soft coal, often with well-defined bands of bright and dull material. The most common coal, with moisture content usually less than 20 percent. Used for generating electricity, making coke, and space heating.

BOD₅.² The biochemical oxygen demand of wastewater during decomposition occurring over a 5-day period. A measure of the organic content of wastewater. See *biological oxygen demand*.

British thermal unit (Btu).³ The quantity of heat required to raise the temperature of one pound of water one degree of Fahrenheit at or near 39.2 degrees Fahrenheit.

Bunker fuel.² Fuel supplied to ships and aircraft for international transportation, irrespective of the flag of the carrier, consisting primarily of residual and distillate fuel oil for ships and jet fuel for aircraft.

Capacity Factor.³ The ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full- power operation during the same period.

Carbon black.² An amorphous form of carbon, produced commercially by thermal or oxidative decomposition of hydrocarbons and used principally in rubber goods, pigments, and printer's ink.

Carbon cycle.² All carbon reservoirs and exchanges of carbon from reservoir to reservoir by various chemical, physical, geological, and biological processes. Usually thought of as a series of the four main reservoirs of carbon interconnected by pathways of exchange. The four reservoirs, regions of the Earth in which carbon behaves in a systematic manner, are the atmosphere, terrestrial biosphere (usually includes freshwater systems), oceans, and sediments (includes fossil fuels). Each of these global reservoirs may be subdivided into smaller pools, ranging in size from individual communities or ecosystems to the total of all living organisms (biota).

Carbon dioxide.² A colorless, odorless, non-poisonous gas that is a normal part of the ambient air. Carbon dioxide is a product of fossil fuel combustion. Although carbon dioxide does not directly impair human health, it is a greenhouse gas that traps terrestrial (i.e., infrared) radiation and contributes to the potential for global warming. See *global warming*.

Carbon dioxide equivalent (CO₂ Eq.).¹ A metric measure used to compare the emissions of the different greenhouse gases based upon their global warming potential (GWP). Greenhouse gas emissions in the United States are most commonly expressed as "teragrams of carbon dioxide equivalents" (Tg CO₂ Eq.). Global warming potentials are used to convert greenhouse gases to carbon dioxide equivalents. See *global warming potential, greenhouse gas*.

Carbon flux.⁹ The rate of exchange of carbon between pools (i.e., reservoirs).

Carbon intensity. The relative amount of carbon emitted per unit of energy or fuels consumed.

- Carbon pool.**⁹ The reservoir containing carbon as a principal element in the geochemical cycle.
- Carbon sequestration.**¹ The uptake and storage of carbon. Trees and plants, for example, absorb carbon dioxide, release the oxygen and store the carbon. Fossil fuels were at one time biomass and continue to store the carbon until burned. See *carbon sinks*.
- Carbon sinks.**¹ Carbon reservoirs and conditions that take-in and store more carbon (i.e., carbon sequestration) than they release. Carbon sinks can serve to partially offset greenhouse gas emissions. Forests and oceans are large carbon sinks. See *carbon sequestration*.
- Carbon tetrachloride (CCl₄).**¹¹ A compound consisting of one carbon atom and four chlorine atoms. It is an ozone depleting substance. Carbon tetrachloride was widely used as a raw material in many industrial applications, including the production of chlorofluorocarbons, and as a solvent. Solvent use was ended in the United States when it was discovered to be carcinogenic. See *ozone depleting substance*.
- Chemical reaction.**⁷ Interaction between chemicals in which there is a change in the chemical composition of the elements or compounds involved.
- Chlorofluorocarbons (CFCs).**⁷ Organic compounds made up of atoms of carbon, chlorine, and fluorine. An example is CFC-12 (CCl₂F₂), used as a refrigerant in refrigerators and air conditioners and as a foam blowing agent. Gaseous CFCs can deplete the ozone layer when they slowly rise into the stratosphere, are broken down by strong ultraviolet radiation, release chlorine atoms, and then react with ozone molecules. See *Ozone Depleting Substance*.
- Climate.**^{1&9} The average weather, usually taken over a 30 year time period, for a particular region and time period. Climate is not the same as weather, but rather, it is the average pattern of weather for a particular region. Weather describes the short-term state of the atmosphere. Climatic elements include precipitation, temperature, humidity, sunshine, wind velocity, phenomena such as fog, frost, and hail-storms, and other measures of the weather. See *weather*.
- Climate change.**¹ The term “climate change” is sometimes used to refer to all forms of climatic inconsistency, but because the Earth's climate is never static, the term is more properly used to imply a significant change from one climatic condition to another. In some cases, “climate change” has been used synonymously with the term, “global warming”; scientists however, tend to use the term in the wider sense to also include natural changes in climate. See *global warming, greenhouse effect, enhanced greenhouse effect, radiative forcing*.
- Climate feedback.**¹ An atmospheric, oceanic, terrestrial, or other process that is activated by direct climate change induced by changes in radiative forcing. Climate feedbacks may increase (positive feedback) or diminish (negative feedback) the magnitude of the direct climate change.
- Climate lag.**¹ The delay that occurs in climate change as a result of some factor that changes very slowly. For example, the effects of releasing more carbon dioxide into the atmosphere may not be known for some time because a large fraction is dissolved in the ocean and only released to the atmosphere many years later.
- Climate sensitivity.**¹ The equilibrium response of the climate to a change in radiative forcing; for example, a doubling of the carbon dioxide concentration. See *radiative forcing*.
- Climate system (or Earth system).**¹ The atmosphere, the oceans, the biosphere, the cryosphere, and the geosphere, together make up the climate system.
- Coal.**² A black or brownish black solid, combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alteration, or coalification, from lignite to anthracite. See *anthracite, bituminous coal, subbituminous coal, lignite*.
- Coal coke.**² A hard, porous product made from baking bituminous coal in ovens at temperatures as high as 2,000 degrees Fahrenheit. It is used both as a fuel and as a reducing agent in smelting iron ore in a blast furnace.
- Coal gasification.**⁷ Conversion of solid coal to synthetic natural gas (SNG) or a gaseous mixture that can be burned as a fuel.
- Coal liquefaction.**⁷ Conversion of solid coal to a liquid fuel such as synthetic crude oil or methanol.

Coalbed methane.² Methane that is produced from coalbeds in the same manner as natural gas produced from other strata. Methane is the principal component of natural gas.

Co-control benefit.¹⁰ It is the additional benefit derived from an environmental policy that is designed to control one type of pollution, while reducing the emissions of other pollutants as well. For example, a policy to reduce carbon dioxide emissions might reduce the combustion of coal, but when coal combustion is reduced, so too are the emissions of particulates and sulfur dioxide.⁵ The benefits associated with reductions in emissions of particulates and sulfur dioxide are the co-control benefits of reductions in carbon dioxide.

Cogeneration.⁷ Production of two useful forms of energy such as high-temperature heat and electricity from the same process.

Combustion.² Chemical oxidation accompanied by the generation of light and heat.

Commercial End-Use Sector: Defined economically, consists of business establishments that are not engaged in transportation or in manufacturing or other types of industrial activities (e.g., agriculture, mining, or construction). Commercial establishments include hotels, motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; religious and nonprofit organizations; health, social, and educational institutions; and Federal, State, and local governments. Street lights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial.

Compost.⁷ Partially decomposed organic plant and animal matter that can be used as a soil conditioner or fertilizer.

Composting.⁷ Partial breakdown of organic plant and animal matter by aerobic bacteria to produce a material that can be used as a soil conditioner or fertilizer. See *compost*.

Compound.⁷ Combination of two or more different chemical elements held together by chemical bonds. See *element*. See *inorganic compound*, *organic compound*.

Concentration.⁷ Amount of a chemical in a particular volume or weight of air, water, soil, or other medium. See *parts per billion*, *parts per million*.

Conference Of Parties (COP).¹⁰ The Conference of the Parties is the “supreme body” of the United Nations Framework Convention on Climate Change (UNFCCC), that is, its highest decision-making authority. It is an association of all the countries that are Parties to the UNFCCC. The COP meets every year, unless the Parties decide otherwise. (unfccc.int)

Conifer.⁷ See *coniferous trees*.

Coniferous trees.⁷ Cone-bearing trees, mostly evergreens, that have needle-shaped or scale-like leaves. They produce wood known commercially as softwood. See *deciduous trees*.

Cooling Degree Days: The number of degrees per day that the average daily temperature is above 65° Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures for a 24 hour period. (See Degree Days)

Criteria pollutant.² A pollutant determined to be hazardous to human health and regulated under EPA's National Ambient Air Quality Standards. The 1970 amendments to the Clean Air Act require EPA to describe the health and welfare impacts of a pollutant as the “criteria” for inclusion in the regulatory regime. In this report, emissions of the criteria pollutants CO, NO_x, NMVOCs, and SO₂ are reported because they are thought to be precursors to greenhouse gas formation.

Crop residue.² Organic residue remaining after the harvesting and processing of a crop.

Crop rotation.⁷ Planting the same field or areas of fields with different crops from year to year to reduce depletion of soil nutrients. A plant such as corn, tobacco, or cotton, which removes large amounts of nitrogen from the soil, is planted one year. The next year a legume such as soybeans, which add nitrogen to the soil, is planted.

Crude oil.² A mixture of hydrocarbons that exist in liquid phase in underground reservoirs and remain liquid at atmospheric pressure after passing through surface separating facilities. See *petroleum*.

Deciduous trees.⁷ Trees such as oaks and maples that lose their leaves during part of the year. See *coniferous trees*.

Decomposition.⁹ The breakdown of matter by bacteria and fungi. It changes the chemical composition and physical appearance of the materials.

Deforestation.¹ Those practices or processes that result in the conversion of forested lands for non-forest uses. This is often cited as one of the major causes of the enhanced greenhouse effect for two reasons: 1) the burning or decomposition of the wood releases carbon dioxide; and 2) trees that once removed carbon dioxide from the atmosphere in the process of photosynthesis are no longer present.

Degradable.⁷ See *biodegradable*.

Degree Days (Population Weighted): Heating or cooling degree days weighted by the population of the area in which the degree days are recorded. To compute State population-weighted degree days, each State is divided into from one to nine climatically homogeneous divisions, which are assigned weights based on the ratio of the population of the division to the total population of the State. Degree day readings for each division are multiplied by the corresponding population weight for each division and those products are then summed to arrive at the State population-weighted degree day value. To compute national population-weighted degree days, the Nation is divided into nine Census regions, each comprising from three to eight States, which are assigned weights based on the ratio of the population of the Nation. Degree day readings for each region are multiplied by the corresponding population weight for each region and those products are then summed to arrive at the national population-weighted degree day value. (See Heating Degree Days, Cooling Degree Days, and Degree Day Normals)

Degree Day Normals: Simple arithmetic averages of monthly or annual degree days over a long period of time (usually the 30 year period of 1961 through 1990). The averages may be simple degree day normals or population-weighted degree day normals.

Desertification.¹ The progressive destruction or degradation of existing vegetative cover to form a desert. This can occur due to overgrazing, deforestation, drought, and the burning of extensive areas. Once formed, deserts can only support a sparse range of vegetation. Climatic effects associated with this phenomenon include increased reflectivity of solar radiation, reduced atmospheric humidity, and greater atmospheric dust (aerosol) loading.

Distillate fuel oil.² A general classification for the petroleum fractions produced in conventional distillation operations. Included are products known as No. 1, No. 2, and No. 4 fuel oils and No. 1, No. 2, and No. 4 diesel fuels. Used primarily for space heating, on and off-highway diesel engine fuel (including railroad engine fuel and fuel for agricultural machinery), and electric power generation.

Economy.⁷ System of production, distribution, and consumption of economic goods.

Ecosystem.¹⁰ The complex system of plant, animal, fungal, and microorganism communities and their associated non-living environment interacting as an ecological unit. Ecosystems have no fixed boundaries; instead their parameters are set to the scientific, management, or policy question being examined. Depending upon the purpose of analysis, a single lake, a watershed, or an entire region could be considered an ecosystem.

Electric Utility Sector: Privately and publicly owned establishments that generate, transmit, distribute, or sell electricity primarily for use by the public and meet the definition of an electric utility. Electric utilities include investor-owned, publicly owned, cooperative, and Federal utilities. Historically, they have generally been vertically integrated companies that provide for generation, transmission, distribution, and/or energy services for all customers in a designated service territory. Nonutility power producers are not included in the electric utility sector.

Electrons.⁷ Tiny particle moving around outside the nucleus of an atom. Each electron has one unit of negative charge (-) and almost no mass.

Element.⁷ Chemicals such as hydrogen (H), iron (Fe), sodium (Na), carbon (C), nitrogen (N), or oxygen (O), whose distinctly different atoms serve as the basic building blocks of all matter. There are 92 naturally occurring elements. Another 15 have been made in laboratories. Two or more elements combine to form compounds that make up most of the world's matter. See *compound*.

Emission inventory. A list of air pollutants emitted into a community's, state's, nation's, or the Earth's atmosphere in amounts per some unit time (e.g. day or year) by type of source. An emission inventory has both political and scientific applications.

Emissions coefficient/factor.² A unique value for scaling emissions to activity data in terms of a standard rate of emissions per unit of activity (e.g., grams of carbon dioxide emitted per barrel of fossil fuel consumed).

Emissions.² Releases of gases to the atmosphere (e.g., the release of carbon dioxide during fuel combustion). Emissions can be either intended or unintended releases. See *fugitive emissions*.

Energy conservation.⁷ Reduction or elimination of unnecessary energy use and waste. See *energy-efficiency*.

Energy intensity.⁵ Ratio between the consumption of energy to a given quantity of output; usually refers to the amount of primary or final energy consumed per unit of gross domestic product.

Energy quality.⁷ Ability of a form of energy to do useful work. High-temperature heat and the chemical energy in fossil fuels and nuclear fuels are concentrated high quality energy. Low-quality energy such as low-temperature heat is dispersed or diluted and cannot do much useful work.

Energy.³ The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. In the United States, electrical energy is often measured in kilowatt-hours (kWh), while heat energy is often measured in British thermal units (Btu).

Energy-efficiency.^{6&8} The ratio of the useful output of services from an article of industrial equipment to the energy use by such an article; for example, vehicle miles traveled per gallon of fuel (mpg).

Enhanced greenhouse effect.¹ The concept that the natural greenhouse effect has been enhanced by anthropogenic emissions of greenhouse gases. Increased concentrations of carbon dioxide, methane, and nitrous oxide, CFCs, HFCs, PFCs, SF₆, NF₃, and other photochemically important gases caused by human activities such as fossil fuel consumption, trap more infra-red radiation, thereby exerting a warming influence on the climate. See *greenhouse gas, anthropogenic, greenhouse effect, climate*.

Enhanced oil recovery.⁷ Removal of some of the heavy oil left in an oil well after primary and secondary recovery. See *primary oil recovery, secondary oil recovery*.

Enteric fermentation.² A digestive process by which carbohydrates are broken down by microorganisms into simple molecules for absorption into the bloodstream of an animal.

Environment.⁷ All external conditions that affect an organism or other specified system during its lifetime.

Ethanol (C₂H₅OH).⁸ Otherwise known as ethyl alcohol, alcohol, or grain spirit. A clear, colorless, flammable oxygenated hydrocarbon with a boiling point of 78.5 degrees Celsius in the anhydrous state. In transportation, ethanol is used as a vehicle fuel by itself (E100), blended with gasoline (E85), or as a gasoline octane enhancer and oxygenate (10 percent concentration).

Evapotranspiration.¹⁰ The loss of water from the soil by evaporation and by transpiration from the plants growing in the soil, which rises with air temperature.

Exponential growth.⁷ Growth in which some quantity, such as population size, increases by a constant percentage of the whole during each year or other time period; when the increase in quantity over time is plotted, this type of growth yields a curve shaped like the letter J.

Feedlot.⁷ Confined outdoor or indoor space used to raise hundreds to thousands of domesticated livestock. See *rangeland*.

Fertilization, carbon dioxide.¹ An expression (sometimes reduced to 'fertilization') used to denote increased plant growth due to a higher carbon dioxide concentration.

Fertilizer.⁷ Substance that adds inorganic or organic plant nutrients to soil and improves its ability to grow crops, trees, or other vegetation. See *organic fertilizer*.

Flaring.⁹ The burning of waste gases through a flare stack or other device before releasing them to the air.

Fluidized bed combustion (FBC).⁷ Process for burning coal more efficiently, cleanly, and cheaply. A stream of hot air is used to suspend a mixture of powdered coal and limestone during combustion. About 90 to 98 percent

of the sulfur dioxide produced during combustion is removed by reaction with limestone to produce solid calcium sulfate.

Fluorocarbons.¹ Carbon-fluorine compounds that often contain other elements such as hydrogen, chlorine, or bromine. Common fluorocarbons include chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). See *chlorofluorocarbons, hydrochlorofluorocarbons, hydrofluorocarbons, perfluorocarbons*.

Forcing mechanism.¹ A process that alters the energy balance of the climate system (i.e., changes the relative balance between incoming solar radiation and outgoing infrared radiation from Earth). Such mechanisms include changes in solar irradiance, volcanic eruptions, and enhancement of the natural greenhouse effect by emission of carbon dioxide.

Forest.⁷ Terrestrial ecosystem (biome) with enough average annual precipitation (at least 76 centimeters or 30 inches) to support growth of various species of trees and smaller forms of vegetation.

Fossil fuel. A general term for buried combustible geologic deposits of organic materials, formed from decayed plants and animals that have been converted to crude oil, coal, natural gas, or heavy oils by exposure to heat and pressure in the earth's crust over hundreds of millions of years. See *coal, petroleum, crude oil, natural gas*.

Fossil fuel combustion.¹ Burning of coal, oil (including gasoline), or natural gas. The burning needed to generate energy release carbon dioxide by-products that can include unburned hydrocarbons, methane, and carbon monoxide. Carbon monoxide, methane, and many of the unburned hydrocarbons slowly oxidize into carbon dioxide in the atmosphere. Common sources of fossil fuel combustion include cars and electric utilities.

Freon. See chlorofluorocarbon.

Fugitive emissions.² Unintended gas leaks from the production processing, transmission, and/or transportation of fossil fuels, CFCs from refrigeration leaks, SF₆ from electrical power distributor, etc.

Gasohol.⁷ Vehicle fuel consisting of a mixture of gasoline and ethyl or methyl alcohol; typically 10 to 23 percent ethanol by volume.

General Aviation.⁸ That portion of civil aviation, which encompasses all facets of aviation except air carriers. It includes any air taxis, commuter air carriers, and air travel clubs, which do not hold Certificates of Public Convenience and Necessity. See *air carriers*.

General circulation model (GCM).¹ A global, three-dimensional computer model of the climate system which can be used to simulate human-induced climate change. GCMs are highly complex and they represent the effects of such factors as reflective and absorptive properties of atmospheric water vapor, greenhouse gas concentrations, clouds, annual and daily solar heating, ocean temperatures and ice boundaries. The most recent GCMs include global representations of the atmosphere, oceans, and land surface.

Geosphere.¹ The soils, sediments, and rock layers of the Earth's crust, both continental and beneath the ocean floors.

Geothermal energy.⁷ Heat transferred from the earth's molten core to under-ground deposits of dry steam (steam with no water droplets), wet steam (a mixture of steam and water droplets), hot water, or rocks lying fairly close to the earth's surface.

Global Warming Potential (GWP).¹ The index used to translate the level of emissions of various gases into a common measure in order to compare the relative radiative forcing of different gases without directly calculating the changes in atmospheric concentrations. GWPs are calculated as the ratio of the radiative forcing that would result from the emissions of one kilogram of a greenhouse gas to that from the emission of one kilogram of carbon dioxide over a period of time (usually 100 years). Gases involved in complex atmospheric chemical processes have not been assigned GWPs. See *lifetime*.

Global warming.¹⁰ The progressive gradual rise of the earth's surface temperature thought to be caused by the greenhouse effect and responsible for changes in global climate patterns. See *enhanced greenhouse effect, greenhouse effect, climate change*.

Grassland.⁷ Terrestrial ecosystem (biome) found in regions where moderate annual average precipitation (25 to 76 centimeters or 10 to 30 inches) is enough to support the growth of grass and small plants but not enough to support large stands of trees.

Greenhouse effect.⁷ Trapping and build-up of heat in the atmosphere (troposphere) near the earth's surface. Some of the heat flowing back toward space from the earth's surface is absorbed by water vapor, carbon dioxide, ozone, and several other gases in the atmosphere and then reradiated back toward the earth's surface. If the atmospheric concentrations of these greenhouse gases rise, the average temperature of the lower atmosphere will gradually increase. See *enhanced greenhouse effect, climate change, global warming*.

Greenhouse gas (GHG).¹ Any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include, but are not limited to, water vapor, carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrochlorofluorocarbons (HCFCs), ozone (O₃), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆). See *carbon dioxide, methane, nitrous oxide, hydrochlorofluorocarbon, ozone, hydrofluorocarbon, perfluorocarbon, sulfur hexafluoride*.

Halocarbons.¹ Chemicals consisting of carbon, sometimes hydrogen, and either chlorine, fluorine, bromine or iodine.

Halons.¹ Compounds, also known as bromofluorocarbons, that contain bromine, fluorine, and carbon. They are generally used as fire extinguishing agents and cause ozone depletion. Bromine is many times more effective at destroying stratospheric ozone than chlorine. See *ozone depleting substance*.

Heat.⁷ Form of kinetic energy that flows from one body to another when there is a temperature difference between the two bodies. Heat always flows spontaneously from a hot sample of matter to a colder sample of matter. This is one way to state the second law of thermodynamics. See *temperature*.

Heat content.⁵ The amount of heat per unit mass released upon complete combustion.

Heating Degree Days: The number of degrees per day that the average daily temperature is below 65° Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures for a 24 hour period. (See Degree Days)

Higher heating value.⁵ Quantity of heat liberated by the complete combustion of a unit volume or weight of a fuel assuming that the produced water vapor is completely condensed and the heat is recovered; also known as gross calorific value. See *lower heating value*.

Histosol.⁹ Wet organic soils, such as peats and mucks.

Hydrocarbons.¹ Substances containing only hydrogen and carbon. Fossil fuels are made up of hydrocarbons. Some hydrocarbon compounds are major air pollutants.

Hydrochlorofluorocarbons (HCFCs).¹ Compounds containing hydrogen, fluorine, chlorine, and carbon atoms. Although ozone depleting substances, they are less potent at destroying stratospheric ozone than chlorofluorocarbons (CFCs). They have been introduced as temporary replacements for CFCs and are also greenhouse gases. See *ozone depleting substance*.

Hydroelectric power plant.⁷ Structure in which the energy of fading or flowing water spins a turbine generator to produce electricity.

Hydrofluorocarbons (HFCs).¹ Compounds containing only hydrogen, fluorine, and carbon atoms. They were introduced as alternatives to ozone depleting substances in serving many industrial, commercial, and personal needs. HFCs are emitted as by-products of industrial processes and are also used in manufacturing. They do not significantly deplete the stratospheric ozone layer, but they are powerful greenhouse gases with global warming potentials ranging from 140 (HFC-152a) to 11,700 (HFC-23).

Hydrologic cycle. The process of evaporation, vertical and horizontal transport of vapor, condensation, precipitation, and the flow of water from continents to oceans. It is a major factor in determining climate through its influence on surface vegetation, the clouds, snow and ice, and soil moisture. The hydrologic cycle is responsible for 25 to 30 percent of the mid-latitudes' heat transport from the equatorial to polar regions.

Hydropower.⁷ Electrical energy produced by falling or flowing water. See *hydroelectric power plant*.

Hydrosphere.⁷ All the earth's liquid water (oceans, smaller bodies of fresh water, and underground aquifers), frozen water (polar ice caps, floating ice, and frozen upper layer of soil known as permafrost), and small amounts of water vapor in the atmosphere.

Industrial End-Use Sector: Comprises manufacturing industries, which make up the largest part of the sector, along with mining, construction, agriculture, fisheries, and forestry. Establishments in this sector range from steel mills to small farms to companies assembling electronic components. Nonutility power producers are also included in the industrial end-use sector.

Infrared radiation.¹ The heat energy that is emitted from all solids, liquids, and gases. In the context of the greenhouse issue, the term refers to the heat energy emitted by the Earth's surface and its atmosphere. Greenhouse gases strongly absorb this radiation in the Earth's atmosphere, and re-radiate some of it back towards the surface, creating the greenhouse effect.

Inorganic compound.⁷ Combination of two or more elements, neither of which is carbon. See *organic compound*.

Inorganic fertilizer.⁷ See *synthetic fertilizer*.

Intergovernmental Panel on Climate Change (IPCC).¹ Recognizing the problem of potential global climate change, the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) established the Intergovernmental Panel on Climate Change (IPCC) in 1988. The role of the IPCC is to assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts and options for adaptation and mitigation. (www.ipcc.ch)

Irreversibilities.¹⁰ Changes that, once set in motion, cannot be reversed, at least on human time scales.

Jet fuel⁸ Includes both naphtha-type and kerosene-type fuels meeting standards for use in aircraft turbine engines. Although most jet fuel is used in aircraft, some is used for other purposes such as generating electricity.

Joule.¹ The energy required to push with a force of one Newton for one meter.

Kerogen.⁷ Solid, waxy mixture of hydrocarbons found in oil shale, with a fine grained sedimentary rock. When the rock is heated to high temperatures, the kerogen is vaporized. The vapor is condensed and then sent to a refinery to produce gasoline, heating oil, and other products. See *oil shale, shale oil*.

Kerosene.² A petroleum distillate that has a maximum distillation temperature of 401 degrees Fahrenheit at the 10 percent recovery point, a final boiling point of 572 degrees Fahrenheit, and a minimum flash point of 100 degrees Fahrenheit. Used in space heaters, cookstoves, and water heaters, and suitable for use as an illuminant when burned in wick lamps.

Landfill.⁷ Land waste disposal site in which waste is generally spread in thin layers, compacted, and covered with a fresh layer of soil each day.

Lifetime (atmospheric).¹ The lifetime of a greenhouse gas refers to the approximate amount of time it would take for the anthropogenic increment to an atmospheric pollutant concentration to return to its natural level (assuming emissions cease) as a result of either being converted to another chemical compound or being taken out of the atmosphere via a sink. This time depends on the pollutant's sources and sinks as well as its reactivity. The lifetime of a pollutant is often considered in conjunction with the mixing of pollutants in the atmosphere; a long lifetime will allow the pollutant to mix throughout the atmosphere. Average lifetimes can vary from about a week (e.g., sulfate aerosols) to more than a century (e.g., CFCs, carbon dioxide). See *residence time*.

Light-duty vehicles.⁸ Automobiles and light trucks combined.

Lignite.² A brownish-black coal of low rank with high inherent moisture and volatile matter content, used almost exclusively for electric power generation. Also referred to as brown coal.

Liquefied natural gas (LNG).⁷ Natural gas converted to liquid form by cooling to a very low temperature.

Liquefied petroleum gas (LPG).² Ethane, ethylene, propane, propylene, normal butane, butylene, and isobutane produced at refineries or natural gas processing plants, including plants that fractionate new natural gas plant liquids.

Litter.⁹ Undecomposed plant residues on the soil surface. See *decomposition*.

Longwave radiation.⁹ The radiation emitted in the spectral wavelength greater than 4 micrometers corresponding to the radiation emitted from the Earth and atmosphere. It is sometimes referred to as terrestrial radiation or infrared radiation, although somewhat imprecisely. See *infrared radiation*.

Low Emission Vehicle (LEV).⁸ A vehicle meeting the low-emission vehicle standards.

Lower heating value.⁵ Quantity of heat liberated by the complete combustion of a unit volume or weight of a fuel assuming that the produced water remains as a vapor and the heat of the vapor is not recovered; also known as net calorific value. See *higher heating value*.

Lubricant.² A substance used to reduce friction between bearing surfaces or as a process material, either incorporated into other materials used as aids in manufacturing processes or as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Other substances may be added to impart or improve useful properties. Does not include by-products of lubricating oil from solvent extraction or tars derived from de-asphalting. Lubricants include all grades of lubricating oils from spindle oil to cylinder oil and those used in greases. Lubricant categories are paraffinic and naphthenic.

Manure.⁷ Dung and urine of animals that can be used as a form of organic fertilizer.

Mass balance.⁹ The application of the principle of the conservation of matter.

Mauna Loa.⁹ An intermittently active volcano 13,680 feet (4,170 meters) high in Hawaii.

Methane (CH₄).¹ A hydrocarbon that is a greenhouse gas with a global warming potential most recently estimated at 21. Methane is produced through anaerobic (without oxygen) decomposition of waste in landfills, animal digestion, decomposition of animal wastes, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion. The atmospheric concentration of methane has been shown to be increasing at a rate of about 0.6 percent per year and the concentration of about 1.7 per million by volume (ppmv) is more than twice its pre-industrial value. However, the rate of increase of methane in the atmosphere may be stabilizing.

Methanol (CH₃OH).⁸ A colorless poisonous liquid with essentially no odor and little taste. It is the simplest alcohol with a boiling point of 64.7 degrees Celsius. In transportation, methanol is used as a vehicle fuel by itself (M100), or blended with gasoline (M85).

Methanotrophic.⁷ Having the biological capacity to oxidize methane to CO₂ and water by metabolism under aerobic conditions. See *aerobic*.

Methyl bromide (CH₃Br).¹¹ An effective pesticide; used to fumigate soil and many agricultural products. Because it contains bromine, it depletes stratospheric ozone when released to the atmosphere. See *ozone depleting substance*.

Metric ton.¹ Common international measurement for the quantity of greenhouse gas emissions. A metric ton is equal to 1000 kilograms, 2204.6 pounds, or 1.1023 short tons.

Mineral.⁷ Any naturally occurring inorganic substance found in the earth's crust as a crystalline solid.

Model year.⁸ Refers to the "sales" model year; for example, vehicles sold during the period from October 1 to the next September 31 is considered one model year.

Molecule.⁷ Chemical combination of two or more atoms of the same chemical element (such as O₂) or different chemical elements (such as H₂O).

Montreal Protocol on Substances that Deplete the Ozone Layer.¹¹ The Montreal Protocol and its amendments control the phaseout of ozone depleting substances production and use. Under the Protocol, several international organizations report on the science of ozone depletion, implement projects to help move away from ozone depleting substances, and provide a forum for policy discussions. In the United States, the Protocol is implemented under the rubric of the Clean Air Act Amendments of 1990. See *ozone depleting substance*, *ozone layer*.

Motor gasoline.² A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, obtained by blending appropriate refinery streams to form a fuel suitable for use in spark-ignition

engines. Motor gasoline includes both leaded and unleaded grades of finished gasoline, blending components, and gasohol.

Municipal solid waste (MSW).² Residential solid waste and some non-hazardous commercial, institutional, and industrial wastes. This material is generally sent to municipal landfills for disposal. See *landfill*.

Naphtha.² A generic term applied to a petroleum fraction with an approximate boiling range between 122 and 400 degrees Fahrenheit.

Natural gas.⁷ Underground deposits of gases consisting of 50 to 90 percent methane (CH₄) and small amounts of heavier gaseous hydrocarbon compounds such as propane (C₃H₈) and butane (C₄H₁₀).

Natural gas liquids (NGLs).² Those hydrocarbons in natural gas that are separated as liquids from the gas. Includes natural gas plant liquids and lease condensate.

Nitrogen cycle.⁷ Cyclic movement of nitrogen in different chemical forms from the environment, to organisms, and then back to the environment.

Nitrogen fixation.⁷ Conversion of atmospheric nitrogen gas into forms useful to plants and other organisms by lightning, bacteria, and blue-green algae; it is part of the nitrogen cycle.

Nitrogen oxides (NO_x).¹ Gases consisting of one molecule of nitrogen and varying numbers of oxygen molecules. Nitrogen oxides are produced, for example, by the combustion of fossil fuels in vehicles and electric power plants. In the atmosphere, nitrogen oxides can contribute to formation of photochemical ozone (smog), impair visibility, and have health consequences; they are considered pollutants.

Nitrous oxide (N₂O).¹ A powerful greenhouse gas with a global warming potential most recently evaluated at 310. Major sources of nitrous oxide include soil cultivation practices, especially the use of commercial and organic fertilizers, fossil fuel combustion, nitric acid production, and biomass burning.

Nonbiodegradable.⁷ Substance that cannot be broken down in the environment by natural processes. See *biodegradable*.

Nonlinearities.¹⁰ Occur when changes in one variable cause a more than proportionate impact on another variable.

Non-methane volatile organic compounds (NMVOCs).² Organic compounds, other than methane, that participate in atmospheric photochemical reactions.

Non-point source.⁷ Large land area such as crop fields and urban areas that discharge pollutant into surface and underground water over a large area. See *point source*.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity of instrumentality that owns electric generating capacity and is not an electric utility. Nonutility producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated, franchised, service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

Nuclear electric power.³ Electricity generated by an electric power plant whose turbines are driven by steam generated in a reactor by heat from the fissioning of nuclear fuel.

Nuclear energy.⁷ Energy released when atomic nuclei undergo a nuclear reaction such as the spontaneous emission of radioactivity, nuclear fission, or nuclear fusion.

Oil shale.⁷ Underground formation of a fine-grained sedimentary rock containing varying amounts of kerogen, a solid, waxy mixture of hydrocarbon compounds. Heating the rock to high temperatures converts the kerogen to a vapor, which can be condensed to form a slow flowing heavy oil called shale oil. See *kerogen, shale oil*.

Oil. See crude oil, petroleum.

Ore.⁷ Mineral deposit containing a high enough concentration of at least one metallic element to permit the metal to be extracted and sold at a profit.

Organic compound.⁷ Molecule that contains atoms of the element carbon, usually combined with itself and with atoms of one or more other element such as hydrogen, oxygen, nitrogen, sulfur, phosphorus, chlorine, or fluorine. See *inorganic compound*.

Organic fertilizer.⁷ Organic material such as manure or compost, applied to cropland as a source of plant nutrients.

Oxidize.² To chemically transform a substance by combining it with oxygen.

Oxygen cycle.⁷ Cyclic movement of oxygen in different chemical forms from the environment, to organisms, and then back to the environment.

Ozone.⁶ A colorless gas with a pungent odor, having the molecular form of O₃, found in two layers of the atmosphere, the stratosphere and the troposphere. Ozone is a form of oxygen found naturally in the stratosphere that provides a protective layer shielding the Earth from ultraviolet radiation's harmful health effects on humans and the environment. In the troposphere, ozone is a chemical oxidant and major component of photochemical smog. Ozone can seriously affect the human respiratory system.

Ozone Depleting Substance (ODS).¹¹ A family of man-made compounds that includes, but are not limited to, chlorofluorocarbons (CFCs), bromofluorocarbons (halons), methyl chloroform, carbon tetrachloride, methyl bromide, and hydrochlorofluorocarbons (HCFCs). These compounds have been shown to deplete stratospheric ozone, and therefore are typically referred to as ODSs.

Ozone layer.⁷ Layer of gaseous ozone (O₃) in the stratosphere that protects life on earth by filtering out harmful ultraviolet radiation from the sun. See *stratosphere, ultraviolet radiation*.

Ozone precursors.² Chemical compounds, such as carbon monoxide, methane, non-methane hydrocarbons, and nitrogen oxides, which in the presence of solar radiation react with other chemical compounds to form ozone, mainly in the troposphere. See *troposphere*

Particulate matter (PM).⁷ Solid particles or liquid droplets suspended or carried in the air.

Particulates. See *particulate matter*.

Parts per billion (ppb).⁷ Number of parts of a chemical found in one billion parts of a particular gas, liquid, or solid mixture. See *concentration*.

Parts per million (ppm).⁷ Number of parts of a chemical found in one million parts of a particular gas, liquid, or solid. See *concentration*.

Pentanes plus.² A mixture of hydrocarbons, mostly pentanes and heavier fractions, extracted from natural gas.

Perfluorocarbons (PFCs).¹ A group of human-made chemicals composed of carbon and fluorine only. These chemicals (predominantly CF₄ and C₂F₆) were introduced as alternatives, along with hydrofluorocarbons, to the ozone depleting substances. In addition, PFCs are emitted as by-products of industrial processes and are also used in manufacturing. PFCs do not harm the stratospheric ozone layer, but they are powerful greenhouse gases: CF₄ has a global warming potential (GWP) of 6,500 and C₂F₆ has a GWP of 9,200.

Petrochemical feedstock.² Feedstock derived from petroleum, used principally for the manufacture of chemicals, synthetic rubber, and a variety of plastics. The categories reported are naphtha (endpoint less than 401 degrees Fahrenheit) and other oils (endpoint equal to or greater than 401 degrees Fahrenheit).

Petrochemicals.⁷ Chemicals obtained by refining (i.e., distilling) crude oil. They are used as raw materials in the manufacture of most industrial chemicals, fertilizers, pesticides, plastics, synthetic fibers, paints, medicines, and many other products. See *crude oil*.

Petroleum coke.² A residue that is the final product of the condensation process in cracking.

Petroleum.² A generic term applied to oil and oil products in all forms, such as crude oil, lease condensate, unfinished oils, petroleum products, natural gas plant liquids, and non-hydrocarbon compounds blended into finished petroleum products. See *crude oil*.

Photosynthesis.⁷ Complex process that takes place in living green plant cells. Radiant energy from the sun is used to combine carbon dioxide (CO₂) and water (H₂O) to produce oxygen (O₂) and simple nutrient molecules, such as glucose (C₆H₁₂O₆).

Photovoltaic and solar thermal energy.² Energy radiated by the sun as electromagnetic waves (electromagnetic radiation) that is converted into electricity by means of solar (i.e., photovoltaic) cells or useable heat by concentrating (i.e., focusing) collectors.

Point source.⁷ A single identifiable source that discharges pollutants into the environment. Examples are smokestack, sewer, ditch, or pipe. See *non-point source*.

Pollution.⁷ A change in the physical, chemical, or biological characteristics of the air, water, or soil that can affect the health, survival, or activities of humans in an unwanted way. Some expand the term to include harmful effects on all forms of life.

Polyvinyl chloride (PVC).² A polymer of vinyl chloride. It is tasteless, odorless and insoluble in most organic solvents. A member of the family vinyl resin, used in soft flexible films for food packaging and in molded rigid products, such as pipes, fibers, upholstery, and bristles.

Population.⁷ Group of individual organisms of the same species living within a particular area.

Prescribed burning.⁷ Deliberate setting and careful control of surface fires in forests to help prevent more destructive fires and to kill off unwanted plants that compete with commercial species for plant nutrients; may also be used on grasslands.

Primary oil recovery.⁷ Pumping out the crude oil that flows by gravity into the bottom of an oil well. See *enhanced oil recovery, secondary oil recovery*.

Quad.⁸ Quad stands for quadrillion, which is, 10^{15} .

Radiation.¹ Energy emitted in the form of electromagnetic waves. Radiation has differing characteristics depending upon the wavelength. Because the radiation from the Sun is relatively energetic, it has a short wavelength (e.g., ultraviolet, visible, and near infrared) while energy re-radiated from the Earth's surface and the atmosphere has a longer wavelength (e.g., infrared radiation) because the Earth is cooler than the Sun. See *ultraviolet radiation, infrared radiation, solar radiation, longwave radiation, terrestrial radiation*.

Radiative forcing.¹ A change in the balance between incoming solar radiation and outgoing infrared (i.e., thermal) radiation. Without any radiative forcing, solar radiation coming to the Earth would continue to be approximately equal to the infrared radiation emitted from the Earth. The addition of greenhouse gases to the atmosphere traps an increased fraction of the infrared radiation, reradiating it back toward the surface of the Earth and thereby creates a warming influence.

Rail.⁸ Includes "heavy" and "light" transit rail. Heavy transit rail is characterized by exclusive rights-of-way, multi-car trains, high speed rapid acceleration, sophisticated signaling, and high platform loading. Also known as subway, elevated railway, or metropolitan railway (metro). Light transit rail may be on exclusive or shared rights of way, high or low platform, multi-car trains or single cars, automated or manually operated. In generic usage, light rail includes streetcars, trolley cars, and tramways.

Rangeland.⁷ Land, mostly grasslands, whose plants can provide food (i.e., forage) for grazing or browsing animals. See *feedlot*.

Recycling.⁷ Collecting and reprocessing a resource so it can be used again. An example is collecting aluminum cans, melting them down, and using the aluminum to make new cans or other aluminum products.

Reforestation.² Replanting of forests on lands that have recently been harvested.

Renewable energy.² Energy obtained from sources that are essentially inexhaustible, unlike, for example, the fossil fuels, of which there is a finite supply. Renewable sources of energy include wood, waste, geothermal, wind, photovoltaic, and solar thermal energy. See *hydropower, photovoltaic*.

Residence time.¹ Average time spent in a reservoir by an individual atom or molecule. Also, this term is used to define the age of a molecule when it leaves the reservoir. With respect to greenhouse gases, residence time usually refers to how long a particular molecule remains in the atmosphere. See *lifetime*.

Residential End-Use Sector: Consists of all private residences, whether occupied or vacant, owned or rented, including single family homes, multifamily housing units, and mobile homes. Secondary home, such as summer homes, are also included. Institutional housing, such as school dormitories, hospitals, and military

barracks, generally are not included in the residential end-use sector, but are instead included in the commercial end-use sector.

Residual fuel oil.² The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations and that conform to ASTM Specifications D396 and D975. Included are No. 5, a residual fuel oil of medium viscosity; Navy Special, for use in steam-powered vessels in government service and in shore power plants; and No. 6, which includes Bunker C fuel oil and is used for commercial and industrial heating, electricity generation, and to power ships. Imports of residual fuel oil include imported crude oil burned as fuel.

Secondary oil recovery.⁷ Injection of water into an oil well after primary oil recovery to force out some of the remaining thicker crude oil. See *enhanced oil recovery, primary oil recovery*.

Sector. Division, most commonly used to denote type of energy consumer (e.g., residential) or according to the Intergovernmental Panel on Climate Change, the type of greenhouse gas emitter (e.g. industrial process). See *Intergovernmental Panel on Climate Change*.

Septic tank.⁷ Underground tank for treatment of wastewater from a home in rural and suburban areas. Bacteria in the tank decompose organic wastes and the sludge settles to the bottom of the tank. The effluent flows out of the tank into the ground through a field of drainpipes.

Sewage treatment (primary).⁷ Mechanical treatment of sewage in which large solids are filtered out by screens and suspended solids settle out as sludge in a sedimentation tank.

Shale oil.⁷ Slow-flowing, dark brown, heavy oil obtained when kerogen in oil shale is vaporized at high temperatures and then condensed. Shale oil can be refined to yield gasoline, heating oil, and other petroleum products. See *kerogen, oil shale*.

Short ton.¹ Common measurement for a ton in the United States. A short ton is equal to 2,000 lbs. or 0.907 metric tons.

Sink.¹ A reservoir that uptakes a pollutant from another part of its cycle. Soil and trees tend to act as natural sinks for carbon.

Sludge.⁷ Goopy solid mixture of bacteria and virus laden organic matter, toxic metals, synthetic organic chemicals, and solid chemicals removed from wastewater at a sewage treatment plant.

Soil.⁷ Complex mixture of inorganic minerals (i.e., mostly clay, silt, and sand), decaying organic matter, water, air, and living organisms.

Soil carbon.⁹ A major component of the terrestrial biosphere pool in the carbon cycle. The amount of carbon in the soil is a function of the historical vegetative cover and productivity, which in turn is dependent in part upon climatic variables.

Solar energy.⁷ Direct radiant energy from the sun. It also includes indirect forms of energy such as wind, falling or flowing water (hydropower), ocean thermal gradients, and biomass, which are produced when direct solar energy interact with the earth. See *solar radiation*.

Solar radiation.¹ Energy from the Sun. Also referred to as short-wave radiation. Of importance to the climate system, solar radiation includes ultra-violet radiation, visible radiation, and infrared radiation.

Source.⁴ Any process or activity that releases a greenhouse gas, an aerosol, or a precursor of a greenhouse gas into the atmosphere.

Special naphtha.² All finished products within the naphtha boiling range that are used as paint thinners, cleaners, or solvents. Those products are refined to a specified flash point.

Still gas.² Any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. Principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, propylene, etc. Used as a refinery fuel and as a petrochemical feedstock.

Stratosphere.⁷ Second layer of the atmosphere, extending from about 19 to 48 kilometers (12 to 30 miles) above the earth's surface. It contains small amounts of gaseous ozone (O₃), which filters out about 99 percent of the

incoming harmful ultraviolet (UV) radiation. Most commercial airline flights operate at a cruising altitude in the lower stratosphere. See *ozone layer, ultraviolet radiation*.

Stratospheric ozone. See *ozone layer*.

Strip mining.⁷ Cutting deep trenches to remove minerals such as coal and phosphate found near the earth's surface in flat or rolling terrain. See *surface mining*.

Subbituminous coal.² A dull, black coal of rank intermediate between lignite and bituminous coal.

Sulfur cycle.⁷ Cyclic movement of sulfur in different chemical forms from the environment, to organisms, and then back to the environment.

Sulfur dioxide (SO₂).¹ A compound composed of one sulfur and two oxygen molecules. Sulfur dioxide emitted into the atmosphere through natural and anthropogenic processes is changed in a complex series of chemical reactions in the atmosphere to sulfate aerosols. These aerosols are believed to result in negative radiative forcing (i.e., tending to cool the Earth's surface) and do result in acid deposition (e.g., acid rain). See *aerosols, radiative forcing, acid deposition, acid rain*.

Sulfur hexafluoride (SF₆).¹ A colorless gas soluble in alcohol and ether, slightly soluble in water. A very powerful greenhouse gas used primarily in electrical transmission and distribution systems and as a dielectric in electronics. The global warming potential of SF₆ is 23,900. See *Global Warming Potential*.

Surface mining.⁷ Removal of soil, sub-soil, and other strata and then extracting a mineral deposit found fairly close to the earth's surface. See *strip mining*.

Synthetic fertilizer.⁷ Commercially prepared mixtures of plant nutrients such as nitrates, phosphates, and potassium applied to the soil to restore fertility and increase crop yields. See *organic fertilizer*.

Synthetic natural gas (SNG).³ A manufactured product chemically similar in most respects to natural gas, resulting from the conversion or reforming of petroleum hydrocarbons. It may easily be substituted for, or interchanged with, pipeline quality natural gas.

Tailings.⁷ Rock and other waste materials removed as impurities when minerals are mined and mineral deposits are processed. These materials are usually dumped on the ground or into ponds.

Tar sand.⁷ Swamp-like deposit of a mixture of fine clay, sand, water, and variable amounts of tar-like heavy oil known as bitumen. Bitumen can be extracted from tar sand by heating. It can then be purified and upgraded to synthetic crude oil. See *bitumen*.

Temperature.⁷ Measure of the average speed of motion of the atoms or molecules in a substance or combination of substances at a given moment. See *heat*.

Terrestrial.⁷ Pertaining to land.

Terrestrial radiation.⁹ The total infrared radiation emitted by the Earth and its atmosphere in the temperature range of approximately 200 to 300 Kelvin. Terrestrial radiation provides a major part of the potential energy changes necessary to drive the atmospheric wind system and is responsible for maintaining the surface air temperature within limits of livability.

Trace gas.¹ Any one of the less common gases found in the Earth's atmosphere. Nitrogen, oxygen, and argon make up more than 99 percent of the Earth's atmosphere. Other gases, such as carbon dioxide, water vapor, methane, oxides of nitrogen, ozone, and ammonia, are considered trace gases. Although relatively unimportant in terms of their absolute volume, they have significant effects on the Earth's weather and climate.

Transportation End-Use Sector: Consists of private and public vehicles that move people and commodities. Included are automobiles, trucks, buses, motorcycles, railroads and railways (including streetcars and subways), aircraft, ships, barges, and natural gas pipelines.

Troposphere.^{1&7} The lowest layer of the atmosphere and contains about 95 percent of the mass of air in the Earth's atmosphere. The troposphere extends from the Earth's surface up to about 10 to 15 kilometers. All weather processes take place in the troposphere. Ozone that is formed in the troposphere plays a significant role in both the greenhouse gas effect and urban smog. See *ozone precursor, stratosphere, atmosphere*.

Tropospheric ozone precursor. See *ozone precursor*.

Tropospheric ozone.¹ See *ozone*.

Ultraviolet radiation (UV).¹¹ A portion of the electromagnetic spectrum with wavelengths shorter than visible light. The sun produces UV, which is commonly split into three bands of decreasing wavelength. Shorter wavelength radiation has a greater potential to cause biological damage on living organisms. The longer wavelength ultraviolet band, UVA, is not absorbed by ozone in the atmosphere. UVB is mostly absorbed by ozone, although some reaches the Earth. The shortest wavelength band, UVC, is completely absorbed by ozone and normal oxygen in the atmosphere.

Unfinished oils.³ All oils requiring further refinery processing, except those requiring only mechanical blending. Includes naphtha and lighter oils, kerosene and light gas oils, heavy gas oils, and residuum.

United Nations Framework Convention on Climate Change (UNFCCC).¹ The international treaty presented at the United Nations Conference on Environment and Development (UNCED) in June 1992. Article 2 of the Convention defines its objective. The UNFCCC also commits signatory Parties to develop and update national inventories of anthropogenic emissions of all greenhouse gases not otherwise controlled by the Montreal Protocol. The UNFCCC was ratified by the United States in 1992, and entered into force in 1995. (unfccc.int)

Vehicle miles traveled (VMT).⁸ One vehicle traveling the distance of one mile. Thus, total vehicle miles is the total mileage traveled by all vehicles.

Volatile organic compounds (VOCs).⁶ Organic compounds that evaporate readily into the atmosphere at normal temperatures. VOCs contribute significantly to photochemical smog production and certain health problems. See *non-methane volatile organic compounds*.

Wastewater.² Water that has been used and contains dissolved or suspended waste materials. See *sewage treatment*.

Water vapor.¹ The most abundant greenhouse gas; it is the water present in the atmosphere in gaseous form. Water vapor is an important part of the natural greenhouse effect. While humans are not significantly increasing its concentration, it contributes to the enhanced greenhouse effect because the warming influence of greenhouse gases leads to a positive water vapor feedback. In addition to its role as a natural greenhouse gas, water vapor plays an important role in regulating the temperature of the planet because clouds form when excess water vapor in the atmosphere condenses to form ice and water droplets and precipitation.

Waxes.² Solid or semisolid materials derived from petroleum distillates or residues. Light-colored, more or less translucent crystalline masses, slightly greasy to the touch, consisting of a mixture of solid hydrocarbons in which the paraffin series predominates. Included are all marketable waxes, whether crude scale or fully refined. Used primarily as industrial coating for surface protection.

Weather.¹ Weather is the specific condition of the atmosphere at a particular place and time. It is measured in terms of such things as wind, temperature, humidity, atmospheric pressure, cloudiness, and precipitation. In most places, weather can change from hour-to-hour, day-to-day, and season-to-season. Climate is the average of weather over time and space. A simple way of remembering the difference is that climate is what you expect (e.g. cold winters) and 'weather' is what you get (e.g. a blizzard). See *climate*.

Wetland.⁷ Land that stays flooded all or part of the year with fresh or salt water.

Wetlands.² Areas regularly saturated by surface or groundwater and subsequently characterized by a prevalence of vegetation adapted for life in saturated-soil conditions.

Wood energy.² Wood and wood products used as fuel, including roundwood (i.e., cordwood), limbwood, wood chips, bark, sawdust, forest residues, and charcoal.

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- ¹¹ U.S. Environmental Protection Agency, Ozone Depletion Glossary, <<http://www.epa.gov/ozone/defns.html>>, February 26, 1999.

ANNEX 7 Uncertainty

The annual U.S. Inventory presents the best effort to produce single-point 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) and the *IPCC Good Practice Guidance* (IPCC 2000). 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 CO₂ Emissions from Fossil Fuel Combustion for example, are considered highly accurate; the uncertainty associated with them is therefore minimal. Other categories of emissions exist, however, for which the inventory emission estimates are considered less certain. The uncertainties that surround these estimates can be attributed to (1) scientific (or model) uncertainty, arising when emission and/or removal processes are not completely understood, and resulting in the use of estimation methodologies based on incomplete or incorrect information; or to (2) a lack of precise input data such as emission factors and activity data (i.e., parameter uncertainty).

Parameter uncertainty is the principal type and source of uncertainty associated with national inventory estimates. Parameter uncertainty has been quantified for most emission sources in the U.S. Inventory. While scientific 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, it would be very difficult—if not impossible—to quantify the model uncertainty associated with most inventory estimates (primarily because, in most cases, only a single model has been developed to estimate emissions for any one source). Model uncertainty was not quantified in this report, though it may be discussed qualitatively.

The primary purpose of the uncertainty analysis conducted in support of the U.S. Inventory is to quantify parameter uncertainty and to evaluate those parameters within the methodologies used to estimate emissions to determine the uncertainty associated with the emission (and removal) estimates presented in the body of this report. By helping to examine data sources, the U.S. Inventory uncertainty analysis provides a strong foundation on which to base future improvements and revisions to the analyses and the Inventory process. For each source category, the analysis highlights opportunities for changes to data measurement, data collection, and calculation methodologies.

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. An important component of the U.S. Greenhouse Gas Inventory Program, 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. The elements of the two approaches are described with their results in the following sections. The United States is in the process of implementing a multi-year strategy to develop quantitative estimates of uncertainty for all source categories. Over time, the United States plans to implement a Tier 2 uncertainty analysis for all sources. As the current year represents the second year of this three- to five-year process, a Tier 2 approach was implemented wherever possible; six source categories that were previously analyzed using a Tier 1 approach were

improved for the current Inventory to include a Tier 2 uncertainty analysis. These include Aluminum Production (IPCC Source Category 2F7), Electrical Transmission and Distribution (IPCC Source Category 2F7), Semiconductor Manufacture (IPCC Source Category 2F6), Magnesium Production and Processing (IPCC Source Category 2C4), Wastewater Treatment (IPCC Source Category 6B), and Human Sewage (Domestic Wastewater) (IPCC Source Category 6B2).

For those sources where a Tier 2 approach was not feasible this year, a Tier 1 approach was implemented. A Tier 1 approach was only adopted for ten source categories, as shown in Figure 7-1. Quantitative uncertainty estimates were not calculated for CO₂ from Natural Gas Flaring (IPCC Source Category 1B2), although emissions from the source do appear in the body of this report. While future efforts will be made to quantify these uncertainties, efforts to date have focused on those source categories characterized by uncertainties expected to have the greatest impact on an overall uncertainty assessment of the inventory. Emissions and sinks from International Bunker Fuels, Biomass Burning, and Ambient Air Pollutants are not included in total emissions estimated for the U.S. Inventory; therefore, no quantitative uncertainty estimates have been developed for these sources.

Characterization of Uncertainty

Both Tier 1 and Tier 2 uncertainty analyses require input variables that are well-characterized. Ideally, each input (i.e., emission factor, activity data point, etc.) would be determined through the careful study of accurately measured data. The variability in such data would provide a reliable estimate of the random uncertainty associated with the measured data. Unfortunately, it is rarely the case that inventory estimates are based on such carefully measured data; more often, inputs are based on a limited number of observations, on expert judgment, or on IPCC recommendations. The characterization of uncertainty associated with these inputs, then, relies heavily on expert judgment.

Because Tier 2 Monte Carlo simulation is both more flexible and more powerful than the Tier 1 method, it is the preferred method for all source categories where sufficient and reliable data is available to characterize inputs. Unless particularly convincing measurements or expert judgment determine otherwise, the probability density functions (PDF) incorporated in the Monte Carlo analyses are limited to uniform, triangular, or normal distributions. The choice among these three PDFs depends largely on observed or measured data and expert judgment. The most common input PDF modeled among all source category analyses that used Monte Carlo simulation was the normal distribution, requiring that the mean and standard deviation of an input's distribution be known or determined. The result of such an analysis typically approximates a normally distributed curve; an example of such a curve is shown in Figure 7-1. If it can be assumed that a particular dataset (e.g., emission factor) is normally distributed, this input distribution generally yields a "tighter" confidence interval and more robust output from the method developed to estimate emissions than does a similar dataset characterized by a uniform distribution (i.e., by a minimum and maximum value).

Figure 7-1. Example of a Normally-Distributed Curve, CH₄ Emissions from Wastewater Treatment

The following sections present results based on Tier 1 or Tier 2 assessments of source category-level uncertainty.

Tier 1 Uncertainty Analyses

The Tier 1 method for estimating uncertainty is based on the error propagation equation, and its derivations as presented in the IPCC Good Practice Guidance, by combining uncertainties associated with activity data and those associated with emission (or other) factors. Inherent in employing the Tier 1 method is the assumption, for each source category, that both activity data and emission factor values are approximately normally distributed, that the coefficient of variation is less than 30 percent, and that the values to be combined are not correlated. Under the direction of the uncertainty analysis coordinator, U.S. Inventory analysts determine the uncertainty associated with source category emissions using standard spreadsheet software. The results are presented for each source category in the body of this report, and are summarized below.

Table 7-1: Uncertainty Estimates Developed Using Tier 1 Uncertainty Analysis

Source Category (IPCC Source Category)	Gas	Base Year Emissions* (Tg CO ₂ Eq.)	2003 Emissions (Tg CO ₂ Eq.)	Uncertainty (Percent of 2003 Emissions)	Trend Uncertainty	Key Source
INDUSTRIAL PROCESSES						
Nitric Acid Production (IPCC Source Category 2B2)	N ₂ O	17.8	15.8	17%	13%	
Adipic Acid Production (IPCC Source Category 2B3)	N ₂ O	15.2	6.0	9%	5%	✓
HCFC-22 Production (IPCC Source Category 2E1)	HFC-23	27.0	12.3	10%	5%	✓
SOLVENT AND OTHER PRODUCT USE						
Nitrous Oxide Product Usage (IPCC Source Category 3D)	N ₂ O	4.3	4.8	7%	11%	
AGRICULTURE						
Agricultural Soil Management (IPCC Source Category 4D)	N ₂ O	253.0	253.5	82%	26%	✓
Field Burning of Agricultural Residues (IPCC Source Category 4F)	N ₂ O	0.4	0.4	68%	+	
Field Burning of Agricultural Residues (IPCC Source Category 4F)	CH ₄	0.7	0.8	69%	1%	
LAND-USE CHANGE AND FORESTRY (SINK)						
Changes in Agricultural Soil Carbon Stocks (IPCC Source Category 5.B.1)**	CO ₂	9.5	9.5	76%	21%	
N ₂ O Fluxes from Settlements Remaining Settlements (IPCC Source Category 5.E.1)	N ₂ O	5.5	6.0	-94 to +483%	38%	
N ₂ O Fluxes from Forest Land Remaining Forest Land (IPCC Source Category 5.A.1)	N ₂ O	0.1	0.4	-96 to +483%	250%	
Changes in Carbon Stocks in Urban Trees (IPCC Source Category 5E1)	N ₂ O	(58.7)	(58.7)	37%	52%	

+ Value is less than 0.05 percent.

*Base Year is 1990 for sources of CO₂, CH₄, and N₂O; the United States has chosen 1995 as the base year for HFCs, PFCs, and SF₆.

**Changes in Agricultural Soil Carbon Stocks in this table includes only that portion of the source category attributable to liming.

Table 7-1 shows base year (1990 or 1995) and current year (2003) emissions for each source category. The combined uncertainty for each source category is expressed as a percent of the total 2003 emissions estimated for that source category. Source category trend uncertainty is described below.

Tier 2 Uncertainty Analyses

If the uncertainties associated with input variables are significantly large, if the distributions underlying the input variables are not characterized by a normal distribution, and/or if the uncertainties have significant correlation, adoption of the Tier 2 method is the preferred approach. The Tier 2 method employs the Monte Carlo Stochastic Simulation technique. This method replicates the equation (or set of equations) used to model the emission (or removal) process for a particular source category many times, using a large sample of randomly-selected values to do so. For each iteration, values for emission factors and activity data are generated through random sampling according to their individual input distributions, or probability density functions. These distributions are assigned as inputs to the analysis for each variable, and depend on observed variances that can be based on measurement studies or on expert judgment. The distribution and frequency of emission values modeled over each series of iterations provide the results of the analysis, and the upper and lower bounds of a 95 percent confidence interval are reported in the body of the report for each source category, and are summarized below in Table 7-2.

Table 7-2: Uncertainty Estimates Developed Using Tier 2 Uncertainty Analysis

IPCC Source Category	Gas	Base Year Emissions* Tg CO ₂ Eq.	2003 Emissions Tg CO ₂ Eq.	2003 Uncertainty (95% Confidence Interval)		Change from Base Year to 2003 Percent	Range of Likely Change From Base Year to 2003		U.S. Inventory Key Sources
				Low	High		Low	High	
ENERGY									
Carbon Dioxide Emissions from Fossil Fuel Combustion (portion of IPCC Source Category 1A)	CO ₂	4,711.7	5,551.6	-1%	6%	18%	16%	24%	✓
Carbon Stored in Products from Non-Energy Uses of Fossil Fuels (portion of IPCC Source Category 1A)	CO ₂	108.0	118.0	-17%	11%	9%	-10%	21%	
Stationary Combustion (excluding CO ₂) (portion of IPCC Source Category 1A)	CH ₄	7.8	6.7	-28%	99%	-15%	-38%	70%	
Stationary Combustion (excluding CO ₂) (portion of IPCC Source Category 1A)	N ₂ O	12.3	13.8	-22%	184%	13%	-12%	221%	
Mobile Combustion (excluding CO ₂)	CH ₄	4.8	2.7	-9%	4%	-44%	-49%	-42%	
Mobile Combustion (excluding CO ₂)	N ₂ O	43.7	42.1	-16%	26%	-4%	-19%	21%	✓
Coal Mining (IPCC Source Category 1B1a)	CH ₄	81.9	53.8	-4%	4%	-34%	-37%	-32%	✓
Abandoned Underground Coal Mines (IPCC Source Category 1B1a)	CH ₄	6.1	6.4	-16%	22%	6%	-11%	29%	
Petroleum Systems (IPCC Source Category 1B2a)	CH ₄	20.0	17.1	-30%	200%	-14%	-40%	157%	✓
Natural Gas Systems (IPCC Source Category 1B2b)	CH ₄	128.3	125.9	-31%	32%	-2%	-32%	30%	✓
Municipal Solid Waste Combustion (IPCC Source Category 1A5)	CO ₂	10.9	18.8	-19%	15%	72%	39%	98%	
Municipal Solid Waste Combustion (IPCC Source Category 1A5)	N ₂ O	0.4	0.5	-71%	192%	10%	-68%	221%	
INDUSTRIAL PROCESSES									
Iron and Steel Production (IPCC Source Category 2C1)	CO ₂	85.4	53.8	-41%	42%	-37%	-63%	-11%	✓
Iron and Steel Production (IPCC Source Category 2C1)	CH ₄	1.3	1.0	-11%	11%	-22%	-31%	-14%	
Cement Manufacture (IPCC Source Category 2A1)	CO ₂	33.3	43.0	-8%	8%	29%	19%	39%	✓
Ammonia Production (IPCC Source Category 2B1)	CO ₂	12.6	9.1	-15%	15%	-28%	-38%	-17%	✓
Urea Application (IPCC Source Category 2B1)	CO ₂	6.8	6.5	-8%	8%	-4%	-12%	3%	✓
Lime Manufacture (IPCC Source Category 2A2)	CO ₂	11.2	13.0	-8%	8%	16%	7%	25%	
Limestone and Dolomite Use (IPCC Source Category 2A3)	CO ₂	5.5	4.7	-7%	8%	-15%	-21%	-8%	
Soda Ash Manufacture and Consumption (IPCC Source Category 2A4)	CO ₂	4.1	4.1	-4%	4%	-1%	-5%	2%	
Titanium Dioxide Production (IPCC Source Category 2B5)	CO ₂	1.3	2.0	-16%	16%	54%	29%	79%	
Phosphoric Acid Production (IPCC Source Category 2A7)	CO ₂	1.5	1.4	-18%	18%	-10%	-26%	7%	
Ferroalloy Production (IPCC Source Category 2C2)	CO ₂	2.0	1.4	-3%	3%	-31%	-33%	-28%	

IPCC Source Category	Gas	Base Year Emissions* Tg CO ₂ Eq.	2003 Emissions Tg CO ₂ Eq.	2003 Uncertainty (95% Confidence Interval)		Change from Base Year to 2003 Percent	Range of Likely Change From Base Year to 2003		U.S. Inventory Key Sources
				Low	High		Low	High	
Carbon Dioxide Consumption (IPCC Source Category 2B5)	CO ₂	0.9	1.3	-5%	5%	47%	40%	54%	
Petrochemical Production (IPCC Source Category 2B5)	CH ₄	1.2	1.5	-7%	7%	30%	21%	39%	
Petrochemical Production (IPCC Source Category 2B5)	CO ₂	2.2	2.8	-10%	10%	25%	13%	38%	
Silicon Carbide Production (IPCC Source Category 2B4)	CH ₄	+	+	-10%	10%	-67%	-70%	-63%	
Substitution of Ozone Depleting Substances (IPCC Source Category 2F)	HFC & PFC	24.4	99.5	-10%	9%	307%	267%	342%	✓
Electrical Transmission and Distribution (IPCC Source Category 2F7)	SF ₆	21.7	14.1	-13%	14%	-35%	-43%	-26%	✓
Aluminum Production (IPCC Source Category 2C3)	CO ₂	6.3	4.2	-34%	40%	-33%	-56%	-6%	
Aluminum Production (IPCC Source Category 2C3)	CF ₄	10.5	3.3	-11%	11%	-69%	-72%	-65%	
Aluminum Production (IPCC Source Category 2C3)	C ₂ F ₆	4.8	0.5	-12%	13%	-89%	-90%	-88%	✓
Semiconductor Manufacture (IPCC Source Category 2F6)	HFC, PFC, SF ₆	5.0	4.6	-20%	23%	-8%	-27%	13%	
Magnesium Production and Processing (IPCC Source Category 2C4)	SF ₆	5.6	3.0	-11%	13%	-47%	-53%	-40%	
AGRICULTURE									
Enteric Fermentation (IPCC Source Category 4A)	CH ₄	117.9	115.0	-11%	18%	-2%	-13%	15%	✓
Manure Management (IPCC Source Category 4B)	CH ₄	31.2	39.1	-18%	20%	26%	3%	51%	✓
Manure Management (IPCC Source Category 4B)	N ₂ O	16.3	17.5	-16%	24%	8%	-9%	34%	
Rice Cultivation (IPCC Source Category 4C)	CH ₄	7.1	6.9	-58%	101%	-3%	-59%	95%	
LAND-USE CHANGE AND FORESTRY (SINK)									
Changes in Forest Carbon Stocks (IPCC Source Category 5A1)	CO ₂	(949.3)	(752.7)	-49%	49%	21%	-18%	60%	
Changes in Agricultural Soil Carbon Stocks (IPCC Source Category 5B1)**	CO ₂	(17.5)	(16.1)	-148%	136%	8%	-117%	133%	
Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills (IPCC Source Category 5E1)	CO ₂	(26.0)	(10.1)	-74%	31%	61%	49%	73%	
WASTE									
Wastewater Treatment (IPCC Source Category 6B)	CH ₄	24.8	36.8	-32%	37%	48%	1%	102%	✓
Human Sewage (Domestic Wastewater) (IPCC Source Category 6B2)	N ₂ O	13.0	15.9	-74%	88%	22%	-68%	129%	
Landfills (IPCC Source Category 6A1)	CH ₄	172.2	131.2	-36%	16%	-24%	-51%	-12%	✓

*Base Year is 1990 for sources of CO₂, CH₄, and N₂O; the United States has chosen 1995 as the base year for HFCs, PFCs, and SF₆.

**Changes in Agricultural Soil Carbon Stocks in this table includes only that portion of the source category attributable to mineral and organic soils.

+ Emissions from this source are less than 0.05 Tg CO₂ Eq.

Trend Uncertainty

In addition to estimates of uncertainty associated with the current year's emission estimates, this Annex also presents estimates of trend uncertainty. The trend is the difference between emissions estimated for the base year and that estimated for the current year. For Tier 1 analyses, trend uncertainty is estimated using the sensitivity of the calculated difference between base year and 2003 emissions to an incremental (i.e., 1 percent) increase in one or both of these values. Two sensitivities are expressed as percentages: Type A sensitivity highlights the effect on the difference between base and 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. For Tier 2 analyses, trend uncertainty is estimated using Monte Carlo Stochastic Simulation; the range of likely change from base year to 2003 is shown in Table 7-2. For the purposes of estimating trend uncertainty in the U.S. Inventory, 1990 is the base year for all CO₂, CH₄, and N₂O source categories, while 1995 is the base year for all sources of HFCs, PFCs, and SF₆.

7.3. Uncertainty Estimation as a Process

The IPCC Good Practice Guidance suggests that the resources expended for characterizing uncertainty associated with an inventory input should be proportional to its importance to the overall uncertainty assessment of the inventory. Therefore, to identify those input variables to which the overall uncertainty in the inventory is highly sensitive, an iterative approach is undertaken wherein, in the first iteration of an uncertainty analysis, initial assessments of the uncertainty of input variables are made and propagated through the inventory in order to preliminarily identify the main sources of uncertainty (in terms of key input variables); subsequently, uncertainty in the key input variables are characterized more accurately through detailed investigations.

Identifying the sources of uncertainties in the emission and sink estimates of the Inventory and quantifying the magnitude of the associated uncertainty is the crucial first step towards improving those estimates. Quantitative assessment of the parameter uncertainties 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 uncertainties within the source category estimates. Such information can be used to prioritize resources with a goal of reducing uncertainties over time within or among inventory source categories and their input parameters. In the current Inventory, potential sources of model uncertainty have been identified for some emission sources, and preliminary parameter uncertainty estimates have been developed for the vast majority of emission source categories.

Thus, a multi-year, multi-stage approach to the quantitative assessment of uncertainty of the U.S. Inventory is underway; the current year's assessment identifying the key sources of uncertainty in the Inventory is the result of the second annual quantitative assessment of uncertainty in the U.S. Inventory. Under this approach, quantitative estimates of uncertainty associated with the overall inventory are being conducted in stages, over a period of three to five years, such that a credible uncertainty assessment for individual source categories and the overall inventory can be developed relying on the IPCC Tier 2 approach.

7.4. Planned Improvements

To estimate emissions and removals from the inventory source categories, IPCC methodologies were applied and supplemented by country-specific methodologies and data. In future inventory reports, additional efforts will be necessary to improve estimation methodologies and data collection procedures, thereby reducing uncertainty. Specific areas that require further research include:

- Incorporating excluded emission sources. Quantitative estimates of the uncertainties 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 associating uncertainty figures with all those 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 CH₄ and N₂O emissions from stationary and mobile combustion is highly uncertain.

- Collecting detailed activity data. Although methodologies exist for estimating emissions for some sources, problems arise in obtaining activity data at a level of detail in which aggregate emission factors can be applied. For example, the ability to estimate emissions of SF₆ from electrical transmission and distribution is limited due to a lack of activity data regarding national SF₆ consumption or average equipment leak rates.

The approach to uncertainty analysis employed in this Inventory recognizes that developing quantitative assessments of uncertainty is not an end in itself, but a crucial step toward improving inventory estimates through systematic analysis and identification of various sources of uncertainty in the inventory estimates. Further, since the reliability of quantitative assessment of uncertainty in the overall Inventory depends upon the accuracy of the uncertainty in the input data, the U.S. plan underscores the importance of developing credible quantitative uncertainty data for the activity- and emission factor-related inventory variables that underlie the emission estimates. This will require extensive use of expert elicitation to obtain the experts' quantitative judgments of uncertainty in the inventory input variables, as many of the inventory estimates for the input variables are point estimates and, often, statistical estimates of uncertainty in these estimates are not available. The United States plans to continue to combine detailed expert elicitation with less formal interviews (based on resource availability) to increase the availability of uncertainty data for the inventory input variables, and ultimately, allow an overall level of uncertainty for the Inventory to be estimated.

References

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