Appendix A
Estimation Methods

Overview

The organization of this appendix generally follows the organization of the body of the report: the discussion is divided by greenhouse gas and by emissions source.

Carbon Dioxide

Most U.S. anthropogenic carbon dioxide emissions result from energy consumption. Energy production contributes a small amount from the flaring of natural gas at oil and gas wells and the scrubbing of carbon dioxide from natural gas, and a number of industrial processes also emit carbon dioxide through non-combustion processes. The largest single source of emissions from these processes is the calcination of limestone in cement production. Other sources include lime manufacture, limestone and dolomite consumption, soda ash manufacture and consumption, industrial carbon dioxide manufacture, and aluminum production. Lastly, some small adjustments are made to reach the total for national emissions. This appendix describes each carbon dioxide emissions source, the estimation methods used, and the data sources.

Several emissions sources are excluded from the carbon dioxide emissions presented in this report, due either to the uncertainty of estimates or because they are based on biomass combustion (which is assumed to be consumed sustainably with a net flux of carbon dioxide to the atmosphere equal to zero). Should the energy use of biomass fuels result in a long-term decline in the total carbon embodied in standing biomass (e.g., forests), the net release of carbon would be treated as a land use issue (see Chapter 6).

Energy Consumption

Emissions Sources

Most U.S. commercial energy is produced through the combustion of fossil fuels, such as coal, natural gas, and petroleum. Chemically, the main components of fossil fuels are hydrocarbons, made up of molecules containing hydrogen and carbon atoms. When these fuels are burned, atmospheric oxygen combines with the hydrogen atoms to create water vapor and with the carbon atoms to create carbon dioxide. In principle, if the amount of fuel burned and the amount of carbon in the fuel are known, the volume of carbon dioxide emitted into the atmosphere can be computed with a high degree of precision. In practice, however, a combination of real-world complexities can reduce the precision of the estimate. These complexities are discussed further in this appendix. Nonetheless, energy-related carbon dioxide emissions are known with greater reliability than are other greenhouse gas emissions sources, and the uncertainty of the estimate is probably in the 3 to 5 percent range. Appendix C, “Uncertainty in Emissions Estimates,” contains an extended discussion of the nature and sources of uncertainty in the estimates.

One real-world complexity is that not all the carbon in fuel is perfectly combusted. About 1.5 percent of the carbon in fossil fuels is emitted in the form of carbon monoxide, which swiftly decays into carbon dioxide in the atmosphere. Another 1 percent is emitted in the form of non-methane volatile organic compounds, which also eventually decay into carbon dioxide. The carbon dioxide emissions reported in Chapter 2 include all “potential” carbon dioxide emissions from the sources covered, including both carbon dioxide emitted directly and carbon emitted in other forms (such as carbon monoxide) that rapidly decay into carbon dioxide in the atmosphere.

Estimation Methods

Carbon emissions in this report were calculated by multiplying energy consumption for each fuel type by an associated carbon emissions coefficient. The result was then modified by subtracting carbon sequestered by nonfuel use. This section describes the derivation of information on energy consumption, emissions coefficients, and carbon sequestered by nonfuel use.

Consumption Data

The Energy Information Administration (EIA) collects a wide variety of information from primary suppliers on a frequent basis and from energy consumers less often, but still in a timely manner. Thus, levels of energy consumption in the United States are fairly well known by end-use sector and detailed fuel type.[1] To estimate carbon dioxide emissions, EIA uses annual data from the four end-use sectors (residential, commercial, industrial, and transportation) and for all the fossil fuels (coal, natural gas, and the full slate of petroleum products). The petroleum products include asphalt and road oil, aviation gasoline, distillate fuel, jet fuel, kerosene, liquefied petroleum gases (LPG), lubricants, motor gasoline, residential fuel, and other petroleum products. Definitions and heating values of the fossil fuels are documented in the appendixes of EIA's recurring reports: the *Annual Energy Review (AER)* and *State Energy Data Report (SEDR)*, as well as the *Petroleum Supply Annual*, *Coal Industry Annual*, and *Natural Gas Annual*. This approach to estimating emissions enables EIA to provide detailed information about trends in sources of emissions.

Information about consumption of "other petroleum" is derived from unpublished EIA data. In recent years, these products have included crude oil, naphtha with a boiling temperature <401°F, petrochemical feedstocks with a boiling temperature ≥401°F, motor gasoline blending components, miscellaneous products, petroleum coke, pentanes plus, still gas, special naphthas, waxes, and unfinished oils.

Emission Coefficients

The amount of carbon released when a fossil fuel is burned depends on the density, carbon content, and gross heat of combustion of the fuel.[2] Most of the coefficients for major fuels are assumed to be constant over time. However, for motor gasoline, LPG, jet fuel, and crude oil, EIA developed annualized carbon emission coefficients to reflect changes in chemical composition or product mix over the years. Appendix B contains a more detailed discussion of the methods employed for developing the coefficients. Table B1 in Appendix B presents a full listing of emissions factors for crude oil, natural gas, and the complete slate of petroleum products.

Methodology for Reallocating Nonutility Power Producers' Fuel Emissions from the Industrial Sector to the Electric Power Sector for Sharing Out to End-Use Sectors

Last year the report *Emissions of Greenhouse Gases in the United States, 1999* contained: "Table 10 U.S. Carbon Dioxide Emissions from Electricity Generation, 1990-1999" that estimated carbon dioxide emissions for both electric utilities and nonutility power producers (NUPPs). This was a standalone table and the emissions from this table were

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[1]Although some of EIA's detailed sectoral surveys are conducted only every 4 years on a sample basis, EIA collects information about apparent consumption of petroleum products (taken as "petroleum product supplied") in mandatory monthly surveys of primary suppliers (e.g., refiners, pipeline operators, importers/exporters, and bulk terminal operators).

[2]Combustion of hydrocarbons results in the production of carbon dioxide, water vapor, and heat. In the United States, the heat resulting from combustion is generally measured as the heat associated with production of water vapor and carbon dioxide. This is commonly referred to as the "higher" or "gross" heating value and is used in EIA statistics on thermal energy. The estimates in this report consistently employ coefficients that reflect the higher heating value assumption. Internationally, however, the "lower" heating value is used. If the lower heating value were used, the Btu content of the fuel would be 5 to 10 percent lower, and the coefficients would be 5 to 10 percent larger, but the carbon emissions estimate would be unchanged. This is sometimes a source of discrepancy. See Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997). Web site www.ipcc.ch/pub/guide.htm.

not integrated with the rest of the report where all fuel inputs to NUPPs were counted in the industrial sector – with the exception of coal consumed by Other Power Producers (OPPs).[3]

As EIA is in the process of changing its integrated data systems for fuel inputs over to a combined electric power sector rather than an electric utility sector, when this process is complete there will be an integrated data series from which to obtain the data needed for this Emissions Report. In the interim (i.e. the 2000 data year) to do this on an integrated basis for the Emissions Report there has been a methodology developed that not only estimates emissions for the electric power sector but that allocates those emissions to all end-use sectors and subtracts the appropriate amount of emissions from fuel inputs for electricity generation from the industrial sector.

The methodology outlined below describes the four-step process employed.

STEP ONE -- Estimate and separate the electrical energy component from the thermal energy component of the fuel consumed by nonutility power producers (NUPPs). For recent years (1999 and 2000), EIA has separated the thermal and electrical component of NUPP data. Therefore it is possible to derive a heat rate (the amount of input energy per kilowatthour of electricity) by comparing the amount of energy consumed with the amount of electricity generated. By using this heat rate as a proxy for heat rates previous to 1999, the thermal energy can be separated from the energy used to generate electricity by multiplying that heat rate times the number of kilowatthours of generation (a number that is known going back to 1989).

Coal

The coal consumed by OPPs for both process heat and electricity generation is counted in the electric power sector in the integrated data in for example Table 2.6 of the Monthly Energy Review (MER).[4] Because of this and because the data on NUPPs elsewhere in the MER contain OPP data, a subtraction of NUPP coal consumption for electricity generation from the total industrial coal category will not work. The coal emissions must first be built from the bottom up within the industrial sector. After this is completed a "net difference" can be calculated. The net difference will not correspond directly to the removal of NUPP energy for electricity, but will be the difference when OPPs are added back into the NUPP power pool and both are subtracted from the industrial sector. This will still represent a net decrease in industrial sector energy.

Method:

- Begin with total coal consumption in quadrillion Btu from Table 1.4 of the MER. From this amount subtract out residential coal consumption (Table 2.2) and commercial coal consumption (Table 2.3).
- Electric utility coal consumption has to be calculated separately because the numbers in Table 2.6 contain data for OPPs. This number is obtained my multiplying the heat content given in Table A5 times the physical unit values for electric utilities given in Tables 6.2 or 7.7.
- The remaining value represents industrial sector coal consumption for coke plants, thermal energy and electricity generation.
- Coking coal in Btu can be calculated by multiplying its physical amount in Table 6.2 times its heat content in table A5.
- When coking coal is subtracted this leaves only coal for thermal output and electric generation in the industrial sector.

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[3]EIA currently uses several terms that are very similar, and that can mean the same thing or have slightly different meanings. The term nonutility generators (NUGs) and nonutility power producers (NUPPs) are synonymous. Independent Power Producers are NUPPs engaged only in the generation of electricity. The other category of NUPP consists of cogenerators. Cogenerators are further divided into conventional cogenerators that produce industrial process heat for their own use and produce electricity as a co-product or by-product and special cogenerators that produce both heat and electricity, but sell both to other parties. These are also called "Other Power Producers." Currently the coal inputs for both the heat and electricity generation of Other Power Producers are counted as input to the electric power sector in EIA's integrated data.

[4]All the table numbers referred to in this discussion are for the Monthly Energy Review, July 2001, unless otherwise specified. A copy of the Monthly Energy Review can be found at http://www.eia.doe.gov/emeu/mer/contents.html

- Table 7.8 gives NUPP coal consumption. For 1999 and 2000 these data contain only coal for electricity generation.

- Using billion kilowatthours of generation (Table 7.4) backcast the electricity only number to 1990 by using the heat rate calculated for 1999 and multiplying it times the generation numbers.
- The above values are used to separate thermal and electricity fuel inputs going back to 1990.

The thermal coal energy stays in the industrial sector and the electricity coal energy value is reallocated from the industrial sector to the electric power sector that is shared out to end-use sectors by electricity sales. It is assumed for this analysis that both direct use and sales to end users by NUPPs in Table 7.5 are industrial uses of electricity. While some of the direct sales to end-users may be to large commercial consumers, the vast majority of it will be to other industrial customers. This may entail some double counting as there is evidence that some sales of end-users is of purchased electricity. However, the data are not currently available to disentangle these values.

Natural Gas

Because all NUPP natural gas consumption is included in the industrial sector data, it is a more straight forward calculation.

Method:
- Take the value for thermal and electric in the industrial sector directly from table 2.4 as it includes all NUPP natural gas consumption. (This number can be checked using the same method used for coal.)
- Starting the same way as with the coal calculation, use table 1.4 to obtain total natural gas consumption from which is subtracted residential and commercial consumption from tables 2.2 and 2.3 respectively.
- Electric utility natural gas consumption can be taken directly from table 2.6 as it is consistent with the data published elsewhere in the MER (i.e. the physical units in Tables 4.4 or 7.7).
- In addition, transportation natural gas consumption from Table 2.5 needs to be subtracted. The resulting value can be compared with the Btu value in Table 2.4. While Table 2.4 can be used directly for the calculation a validation check reveals that the numbers are within plus 6 and minus 8 trillion Btu out of 8,000 to 10,000 trillion Btu.
- Using the natural gas data in Tables 7.4 and 7.8 perform the same calculation as above in order to separate the thermal and electrical energy fuel input for years prior to 1999.

Petroleum

While petroleum provides a relatively small amount of fuel for NUPP electricity generation, it is a complex calculation due to the various types of petroleum-based fuels.

Method:

- Using the same method as for natural gas above one can arrive at a calculated value that can be checked against the value for petroleum in Table 2.4. A check indicates that for most cases the same number as in Table 2.4 was produced and where there are differences they are extremely small.
- There are three different petroleum fuel types: light, heavy and petroleum coke. As in the above method, Table 7.4 (generation) was used to arrive at a heat rate and to backcast using the 1999 value for the years 1990 to 1998 for the electricity only portion of petroleum consumption. This is a small number compared to the other fossil fuels.

STEP TWO – Subtract out the energy value of the fuel used by NUPPs to generate electricity from the total fuel used in the industrial sector. Now that there has been a value calculated by fuel for the electrical energy component of industrial energy consumption, that value can be subtracted from the industrial sector fuel use. This leaves only the energy that is consumed directly in the industrial sector for process heat and other non-electric applications.

Coal

As mentioned above the coal calculation is complicated by the inclusion of the OPPs in the electric power sector rather than in the industrial sector in the MER data set upon which the greenhouse gas estimates are based. This difference is quite large. For example, total industrial coal consumption in Table 2.4 is 2.257 quadrillion Btu. When this value is calculated to include all NUPP including OPPs this value is 4.8 quadrillion Btu – over twice the amount. Therefore simply subtracting the NUPP coal for electricity from the existing industrial sector data will yield a double subtraction because the NUPP electricity coal calculation contains OPP electricity coal while the MER-based industrial sector coal does not. For coal then the entire category needs to be built up from the bottom – adding thermal to coking coal. When this amount is calculated the difference from the MER-based industrial sector coal value can be calculated as a subtraction. This subtraction represents the net change that results from the following:

- Add back both electrical and thermal energy from coal for OPPs in the industrial sector,
- Calculate the coal-fired thermal and electrical energy for all NUPPs,
- Leave the thermal component in the industrial sector,
- Include the coal electrical generation component in the total for electric power generation to be shared out to all the sectors,
- Subtract the net difference from the industrial sector.

Natural Gas

Because all natural gas associated with NUPPs is included in the industrial sector data, the value associated with electricity generation can be directly subtracted from the industrial sector total.

Petroleum

This adjustment is relatively small and can be made the same way as the natural gas adjustment – i.e. as a direct subtraction from the total. The complexity in the petroleum estimate is due to the different types of fuel with differing emission factors. For that reason they are calculated separately.

STEP THREE – Apply the appropriate emission factors to the energy values of the fuels reallocated from the industrial sector to the electric power sector. Now that the fossil fuel used to generate electricity has been reallocated from the industrial sector to the electric power sector, the emissions associated with that energy consumption can be estimated. The reallocated amounts of energy are multiplied times the appropriate emissions factor for that sector. Because emission factors can vary by sector (even for the same fuel) this part of the reallocation can cause small changes in total emissions. The amounts of these changes are in the range of 0.1 to 0.2 MMTCe out of total energy emissions of over 1,500 MMTCe in recent years.

STEP FOUR – Combine all the electricity-related emissions and share them out to the end use sectors to produce new total emissions by sector. To complete the process the total emissions for the electric power sector including electric utilities, nonutility power producers and the electricity component of industrial cogenerators is shared out to each end-use sector by using the sector's share of total electricity sales. It is assumed that NUPP direct sales to end-users are all to other large industrials since data are not available to determine how much of the electricity may be going to large commercial customers.

Once the Btu value of electrical energy has been removed by fuel from thermal energy that value is used to calculate carbon dioxide emissions that are combined with emissions from electric utilities and shared out to all end-use sectors by electricity consumption. This is a relatively straight-forward calculation, however some adjustments must be made. Table 7.5 is the source for the electricity end-use data upon which the shares are calculated. In this table the end-use sectors are: residential, commercial, industrial and "Other." Other is a combination of transportation (railroads and railways) and sales to public authorities for streetlights and similar uses.

All the NUPP electricity in the categories "Direct Use," or "Sales to End Users," are assumed to be industrial sector electricity since most of the sales to end-users are other industrial concerns. The remaining electricity is already

included in the electric-utility retail sales category. The amount of electricity that is sold through the grid to other sectors can be calculated by subtracting the NUPP total from Table 7.5 from the total on Table 7.4. For example in 2000 the total from Table 7.5 is 208.4 billion kWh, while the total from Table 7.4 is 784.6 billion kWh. This indicates that 576.2 billion kWh are generated by NUPPs and sold through the grid, some of which in turn ends up being purchased by industrial customers, but some of which is purchased by commercial, residential and transportation customers.

The additional amount shared out to the residential, commercial and transportation customers by virtue of the inclusion of NUPP fuel inputs represents the amount of the transfer from the industrial sector to these other sectors. The emissions from fossil fuels are shared out among sectors based on total generation (i.e. fossil and non-fossil), regardless of the type of generation, as there is not a way to map generation types to end-use customers within sectors.

Implementation within Greenhouse Gas Spreadsheets

To implement these changes a new spreadsheet was created (alternative01). This spreadsheet calculates the above values and then transmits the Btu values to the appropriate sectoral spreadsheets where they are multiplied times the emission factors in the same way as the original method. The spreadsheets are marked with an "N" to indicate the new method (e.g. NResidential). The old method is maintained as a point of reference. The new sectoral allocations are added together in "Totalsnew." These spreadsheets look the same as those developed for the original method. Once the integrated data within EIA has incorporated nonutility power producers into the electric power sector, this method will no longer be needed and the data will draw upon the older and more direct methodology. For the calculated reallocation of emissions see Table A1.

Table A1. Changes in Values for the Old Versus the New Method for the Treatment of Nonutility Power Producers, 1990 to 2000

(Million Metric Tons of Carbon Equivalent)

Energy Sector Totals	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	P2000
Residential (old)	255.27	259.28	258.53	274.19	271.95	273.40	289.65	288.61	289.30	291.58	302.34
Residential (new)	257.04	261.62	261.81	278.35	275.80	277.85	293.92	292.75	293.70	298.79	313.36
Commercial (old)	208.70	208.30	207.81	213.55	216.95	220.59	229.24	241.45	244.78	246.16	257.32
Commercial (new)	210.28	210.37	210.76	217.22	220.40	224.62	233.06	245.38	250.42	253.06	267.83
Industrial (old)	455.90	444.37	461.55	460.95	470.74	469.38	483.96	489.72	479.77	480.03	487.20
Industrial (new)	452.66	439.81	455.06	452.89	463.26	461.07	476.05	481.54	469.54	465.79	465.71
Transportation (old)	431.76	424.24	431.07	436.36	449.30	457.75	468.86	473.64	481.55	499.45	514.82
Transportation (new)	431.76	424.24	431.07	436.36	449.30	457.75	468.86	473.64	481.55	499.45	514.82
Total (old)	1351.63	1336.19	1358.96	1385.05	1408.94	1421.13	1471.71	1493.42	1495.40	1517.22	1561.67
Total (new)	1351.73	1336.03	1358.71	1384.83	1408.76	1421.29	1471.89	1493.30	1495.22	1517.09	1561.71
Electric Power (old)	483.15	479.53	480.52	497.67	504.59	504.28	523.82	543.57	562.98	558.67	573.26
Electric Power (new)	506.98	505.98	512.03	532.43	540.71	542.53	562.15	583.07	607.21	612.60	641.58
Differences											
Residential (new-old)	1.77	2.34	3.28	4.16	3.85	4.45	4.27	4.14	4.40	7.21	11.02
Commercial (new-old)	1.58	2.07	2.95	3.67	3.45	4.03	3.82	3.93	5.64	6.90	10.50
Industrial (new-old)	-3.25	-4.57	-6.49	-8.06	-7.49	-8.31	-7.91	-8.19	-10.23	-14.24	-21.48
Transportation (new-old)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total (new-old)	0.10	-0.16	-0.26	-0.23	-0.19	0.17	0.19	-0.12	-0.18	-0.13	0.04
Electric Power (new-old)	23.83	26.45	31.52	34.77	36.12	38.25	38.32	39.50	44.22	53.93	68.32

Source: Methodology outlined in this report.

Changes to Energy Consumption Data

While, in general, emissions can be estimated simply by multiplying fuel consumption by the appropriate emissions coefficients, several small adjustments to EIA energy statistics are necessary to eliminate double counting or miscounting of emissions. Usually the adjustments amount to less than 0.1 percent of energy-related carbon emissions. They include:

- **Ethanol.** About 70 million barrels of ethanol are included in annual U.S. gasoline consumption after 1992. Because ethanol is a biofuel, the carbon it contains should not be counted as an emission. Hence, carbon from ethanol is deducted from transportation gasoline consumption. Ethanol consumption is reported in EIA's *Renewable Energy Annual* and the *Petroleum Supply Annual*.

- **Synthetic gas from coal.** Small amounts of "supplemental gas," particularly, gas from the Great Plains Coal Gasification Plant in North Dakota, are manufactured from coal. The coal is counted in industrial energy consumption, and the gas is shipped into the pipeline system. EIA deducts the carbon in synthetic gas (as reported in the *Natural Gas Annual*) from industrial coal emissions.

- **Still gas to pipelines.** Several refineries sell small volumes of "still gas" as supplemental gas to pipelines. EIA deducts the carbon in still gas sales to pipelines (as reported in the *Natural Gas Annual*) from industrial "other petroleum" consumption.

- **Biogas.** The *Natural Gas Annual* reports that small volumes of "supplemental gas" of biological origin (probably landfill gas) are incorporated in U.S. pipeline gas supplies. In keeping with the accounting rule of excluding carbon of biological origin, these supplies are deducted from U.S. natural gas consumption.

- **Carbon dioxide in geothermal steam.** Geothermal steam at The Geysers in Guerneyville, California, where most U.S. geothermal electric power is generated, contains appreciable amounts of carbon dioxide dissolved in the steam, which is released into the atmosphere when the steam is brought to the Earth's surface for power production. EIA includes emissions from this source, at a rate of less than 0.1 million metric tons of carbon per year.

Carbon Sequestration: Nonfuel Use of Fossil Fuels

Gross emissions can be estimated by multiplying fossil fuel consumption by an emissions factor embodying the estimated carbon content of the fuel. However, portions of the fossil fuels consumed are not actually combusted but are used as chemical feedstocks, construction materials, lubricants, solvents, or reducing agents (Table A2). EIA estimates "nonfuel" use of fossil fuels annually in Table 1.15 of the *Annual Energy Review*.[5] For this report, EIA has estimated the fate of the carbon in fuels used for nonfuel purposes (see Table 5 in Chapter 2), based on the rates of sequestration shown in Table A3. Some but not all of the carbon is emitted to the atmosphere. The principal nonfuel uses of fossil fuels, the methods of estimating nonfuel consumption, and the fate of the carbon are listed below.

[5]Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), p. 33.

Table A2. Fossil Fuel Consumption for Nonfuel Use, 1990,1992-2000
(Quadrillion Btu)

	1990	1992	1993	1994	1995	1996	1997	1998	1999	P2000
Petroleum										
Asphalt and Road Oil	1.17	1.10	1.15	1.17	1.18	1.18	1.22	1.26	1.32	1.28
LPG	1.20	1.39	1.35	1.55	1.59	1.65	1.67	1.60	1.81	1.86
Pentanes Plus	0.08	0.06	0.28	0.26	0.30	0.32	0.30	0.27	0.33	.31
Lubricants	0.36	0.33	0.34	0.35	0.35	0.34	0.35	0.37	0.37	.37
Industrial	0.19	0.17	0.17	0.18	0.18	0.17	0.18	0.19	0.19	.19
Transportation	0.18	0.16	0.16	0.17	0.17	0.16	0.17	0.18	0.18	.18
Petro-chem Feed	1.12	1.20	1.22	1.26	1.21	1.21	1.40	1.40	1.31	1.34
Petroleum Coke	0.18	0.25	0.17	0.18	0.19	0.21	0.18	0.31	0.38	.23
Special Naphtha	0.11	0.10	0.10	0.08	0.07	0.07	0.07	0.11	0.15	.10
Other: Waxes & Misc., Dist., and Resid.	0.23	0.20	0.20	0.20	0.20	0.19	0.20	0.22	0.21	.21
Total Petroleum	4.46	4.64	4.80	5.05	5.08	5.17	5.40	5.54	5.88	5.69
Coal	0.02	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.02	.03
Natural Gas	0.59	0.61	0.61	0.69	0.67	0.68	0.70	0.73	0.75	.71
to Fertilizers	0.28	0.35	0.33	0.34	0.33	0.34	0.34	0.37	0.38	.34
Total	5.07	5.29	5.45	5.77	5.79	5.88	6.12	6.27	6.61	6.43

P = preliminary data.

Notes: Asphalt and lubricants are as reported in EIA's *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999) for 1990-1997, and *Monthly Energy Review*, DOE/EIA-0035(2001/07) (Washington, DC, July 2001) for 1998-2000. Some slight differences exist between this table and the *Annual Energy Review*. Data in this table are revised from the data contained in the previous EIA report, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99) (Washington, DC, October 2000).

Source: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001), Table 1.15, p. 33, and underlying estimates.

- **Natural Gas.** Nonfuel use of natural gas is based on periodic (1985, 1988, 1991, 1994 and 1998) reports in EIA's Manufacturing Energy Consumption Survey (MECS). Based on MECS, nonfuel use is divided into three categories: nitrogenous fertilizers, other chemical use, and all other nonfuel uses. Feedstock use of natural gas to make nitrogenous fertilizers is a nonsequestering use, because the underlying chemical in nitrogenous fertilizers is ammonia (NH_3), which is manufactured by steam reforming of natural gas and reacting the synthesis gas with atmospheric nitrogen, leaving the carbon in the feedstock literally "up in the air." In many cases, the carbon dioxide is recovered to make urea or for industrial use. However, carbon in urea and industrial carbon dioxide are generally only temporarily delayed on their way to the atmosphere. EIA assumes that other nonfuel uses in the chemical industry result in 100-percent carbon sequestration. Natural gas is used as a feedstock for a range of chemical products other than ammonia, particularly methanol. Although the methanol used to make methyl tertiary butyl ether (MTBE) winds up in the gasoline pool and is combusted, EIA already counts the carbon in MTBE in gasoline emissions, and to count it again in the feedstock would be double counting. Future research on the fate of the carbon in feedstocks for other chemical industry uses will probably gradually reduce the 100-percent sequestration share currently assumed.

- **Liquefied Petroleum Gases.** Nonfuel use of LPG (ethane, propane, and butane) through 1996 is estimated on the basis of sales of these products to the chemical industry, as reported in the American Petroleum Institute (API) survey, *Sales of Natural Gas Liquids and Liquefied Refinery Gases*, from which EIA deducts chemical industry fuel use of LPG as reported periodically in the MECS. For 1997-2000 the sales to the chemical industry are estimated based on the 1996 ratio of the API's data to EIA's *Petroleum Supply Annual* (PSA) value for LPG, which is then multiplied by the PSA data for 1997-2000. Most of the ethane, propane, and butane used by the chemical industry is used to manufacture ethylene, propylene, and butadiene, respectively, all of which are intermediate products for plastics. Following the recommendation of the Intergovernmental Panel on Climate

Change (IPCC), EIA assumes that 80 percent of nonfuel use is sequestered in plastics, synthetic rubber, and related products.[6]

- **Asphalt and Road Oil.** EIA assumes that asphalt and road oil use is nonfuel use by definition, and that all carbon in asphalt and road oil is sequestered.

- **Pentanes Plus.** "Pentanes plus" are hydrocarbons heavier than butane extracted from natural gas at gas processing plants. Their principal uses are as contributors to the gasoline pool and as petrochemical feedstocks. Nonfuel use of pentanes plus is estimated on the basis of the API's annual survey of natural gas liquids and refinery gases sold to the chemical industry. Following IPCC practice for LPG, EIA assumes that 80 percent of the carbon in pentanes plus used by the chemical industry is sequestered.

- **Petrochemical Feedstocks.** EIA's petroleum surveys recognize two categories of products called "petrochemical feedstocks." These are presumably naphtha and gas oils destined for ethylene crackers, and probably some mix of aromatic hydrocarbons (benzene, toluene, and xylene) and feedstocks used to make aromatic hydrocarbons. All petrochemical feedstock supplies are included in nonfuel use by definition, and, following the practice of the IPCC, EIA assumes that 75 percent of the carbon in synthetic feedstocks and 50 percent of the carbon in gas oil feedstock is sequestered in plastics, synthetic fibers, and related products.

- **Distillate and Residual Fuels.** The MECS reports small volumes (10 million barrels and 1 million barrels, respectively) of distillate and residual oils used for nonfuel purposes in the chemical industry. Following the practice for gas oil petrochemical feedstocks, EIA assumes 50-percent sequestration. Future research may shed more light on the industrial processes that use these fuels.

- **Petroleum Coke.** Petroleum coke is a coal-like solid, about 90 percent carbon by weight, created after intensive extraction of lighter hydrocarbons from petroleum feedstocks by oil refiners. Most petroleum coke is used in the refineries as fuel or as a catalyst. EIA estimates nonfuel use by taking the quantity of petroleum coke supplied and deducting all known fuel uses (refinery use from the *Petroleum Supply Annual*, electric utility use from the *Electric Power Annual*, and industrial use from the MECS). EIA assumes that 50 percent of the carbon in petroleum coke for nonfuel use is sequestered. It should be noted, however, that significant sequestering nonfuel uses of petroleum coke in the United States are difficult to identify. In conjunction with the Environmental Protection Agency this estimate is currently under evaluation and it may yield a downward estimation in the sequestering amounts allocated to petroleum coke. The principal identified nonfuel use is for sacrificial anodes in primary aluminum smelting, a nonsequestering use that EIA counts separately under process emissions (see the next section). It appears that petroleum coke is also used in small quantities by many different industries as a reducing agent (a source of carbon monoxide that, in turn, can be used to scour oxygen from products such as lead oxide (to produce lead) or iron oxide (to produce iron). These are, however, nonsequestering uses.

[6]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 1.28, web site www.ipcc.ch/pub/guide.htm.

Table A3. Rates of Sequestration for U.S. Fossil Fuel Consumption

Fuel Type	Fraction of Fuel Combusted	Fraction of Nonfuel Use of Energy Sequestered
Petroleum		
Motor Gasoline	0.99	--
LPG	0.995	0.8
Jet Fuel	0.99	--
Distillate Fuel	0.99	0.5
Residual Fuel	0.99	0.5
Asphalt and Road Oil	0.99	1
Lubricants	0.99	0.5
Petrochemical Feed	0.99	0.75
Aviation Gas	0.99	--
Kerosene	0.99	--
Petroleum Coke	0.99	0.5
Special Naphtha	0.99	0
Other		
Aviation Gas		
Blending Components	0.99	--
Crude Oil	0.99	--
Naphtha <401oF	0.99	0.75
Other Oil 401oF	0.99	0.5
Petrochemical Feed		
Still Gas	0.99	0.8
Motor Gasoline		
Blending Components	0.99	--
Miscellaneous	0.99	1
Natural Gasoline	0.99	--
Plant Condensate	0.99	--
Pentanes Plus	0.99	0.8
Still Gas	0.995	--
Special Naphthas	0.99	0
Unfinished Oils	0.99	--
Unfractionated Stream	0.99	--
Waxes	0.99	1
Coal		
Residential and Commercial	0.99	--
Industrial Coking	0.99	0.75
Industrial Other	0.99	--
Electric Utility	0.99	--
Natural Gas		
Flare Gas	1	--
Natural Gas	0.995	0.29-0.52
Crude Oil	0.99	--

Sources: EIA estimates documented in this chapter; and Intergovernmental Panel on Climate Change, Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Vol. 3 (Paris, France, 1997), pp. 1.28-1.29, web site www.iea.org/ipcc/invs6.htm.

- **Still Gas.** Still gas is the gas that floats to the top of distillation columns in oil refineries. Its chemical composition is a highly variable blend of free hydrogen, methane, carbon monoxide, and heavier hydrocarbons, depending on the refinery process, the feedstock, and process conditions. EIA estimates nonfuel use by deducting all known fuel uses (refinery fuel use from the *Petroleum Supply Annual* and pipeline gas supplies from the *Natural Gas Annual*). The remainder is assumed to be dispatched to chemical plants as a feedstock. Following the IPCC practice for LPG, EIA assumes that 80 percent of the carbon in still gas is sequestered.

- **Special Naphtha.** "Special naphtha" is a catch-all for an array of hydrocarbon-based solvents, such as hexane and the volatile oils used in petroleum-based paint. In general, solvents evaporate into the atmosphere as "nonmethane volatile organic compounds" after use and swiftly weather into atmospheric carbon dioxide. EIA assumes that all special naphthas are for nonfuel use and that no carbon in special naphtha is sequestered.

- **Lubricants.** The most common petroleum-based lubricant is motor oil, but the category also includes numerous other products, such as industrial greases. Following the IPCC, EIA assumes that 50 percent of the carbon in lubricants is sequestered. The ultimate fate of lubricants is not easy to determine. For example, it is often the case that "recycling" motor oil means burning it as boiler fuel.

- **Waxes and Polishes.** The principal use of waxes is to make wax paper and food packaging materials, which usually end up in landfills. Following the IPCC, EIA assumes 100-percent nonfuel use and 100-percent carbon sequestration for these materials.

- **Miscellaneous.** EIA assumes 100-percent nonfuel use and 100-percent carbon sequestration for this category.

- **Coal.** The manufacture of coke is the largest nonfuel use of coal. By convention, however, coke manufacture is treated as a fuel use. This is not unreasonable, because coke is almost always ultimately combusted. Coke is manufactured by "cooking" high-grade coal in huge ovens in the absence of oxygen. Volatile materials, moisture, and certain categories of impurities are driven off, leaving behind a high-carbon material suitable for metallurgical use. Among the byproducts of the process are "coal tars" or "coal liquids," which typically are rich in aromatic hydrocarbons, such as benzene. Coal tars generally are used as feedstocks in the chemical industry. "Nonfuel use" of coal, as defined for this report, consists of the coal tars driven off during the manufacture of coke. Coal tar production was obtained, for years prior to 1995, from the International Trade Commission's *Synthetic Organic Chemicals*. Since 1995, production has been estimated on the basis of the ratio of 1994 coke production to coal tar production. Following the IPCC guidelines, EIA assumes that 75 percent of the carbon in coal tars is sequestered.

Carbon Sequestration: Fraction Combusted

A small amount of carbon sequestration is associated with the combustion of fossil fuels. Using IPCC assumptions, EIA assumes that oxidation of liquid and solid fuels during combustion is 99 percent complete, and that 1 percent of the carbon remains sequestered. Oxidation of gaseous fuels (LPG and natural gas) is assumed to be 99.5 percent complete.[7] Conceptually, fuel may be "lost" before combustion due to evaporation, leaks, or spills; it may be subject to incomplete combustion and vented to the atmosphere in the form of volatile organic compounds or particulates; or it may remain at the site of combustion in the form of carbon-containing ash or soot.

Data Sources

Fossil Fuel Consumption: (1990-1997), Energy Information Administration, *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999). (1998-2000), Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/07) (Washington, DC, July 2001); *Petroleum Supply Annual 2000*, DOE/EIA-0340(2000)/1

[7]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 1.29, web site www.ipcc.ch/pub/guide.htm.

(Washington, DC, June 2001); *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000); and *Renewable Energy Annual 2000*, DOE/EIA-0603(2000) (Washington, DC, December 2000).

Nonfuel Use of Energy and Biofuels Consumption: Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-384(2000) (Washington, DC, August 2001); Energy Information Administration, *Manufacturing Consumption of Energy*, DOE/EIA-0512(various years) (Washington, DC); American Petroleum Institute, *Sales of Natural Gas Liquids and Liquefied Refinery Gas* (various years); U.S. International Trade Commission, *Synthetic Organic Chemicals*, USITC Publication 2933 (various years through 1994); and Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 1.28,www.ipcc.ch/pub/guide.htm

Adjustments to U.S. Energy Consumption

In recent years, there have been several estimates of U.S. carbon emissions, some of which differ by as much as 5 percent. Two significant reasons for the differences in emissions estimates (beyond those associated with differences in coefficients) are the definitions of “energy consumption” and “the United States” employed by researchers. Subtle differences in definition can produce variations of several percentage points in reported energy consumption and, hence, in carbon emissions. Some estimates include U.S. territories while others exclude them. If consumption is estimated as “apparent consumption” based on production plus imports minus exports plus stock change, then statistical discrepancies will be included in consumption. International bunker fuels are sometimes counted as domestic consumption and sometimes as exports. This section describes how each adjustment is accommodated in the EIA estimates.

U.S. Territories

Emissions Sources

EIA’s energy data for the United States cover only the 50 States and the District of Columbia. In contrast, energy data produced by the International Energy Agency for the United States cover the 50 States plus U.S. territories, including Puerto Rico, the U.S. Virgin Islands, and Guam. Annual energy consumption in the U.S. territories is only about 0.5 quadrillion Btu (Table A4). For the territories as a group, oil consumption ranges between 220,000 and 325,000 barrels per day, and coal consumption averages 315,000 to 425,000 short tons per year, in the U.S. Virgin Islands and Puerto Rico.

Estimation Methods

Energy consumption for U.S. territories is converted to carbon emissions by using the same emissions coefficients applied to U.S. energy data. Carbon emissions for U.S. territories range from 9 to 12 million metric tons per year (see Table 4 in Chapter 2). Because a large portion of reported energy consumption in U.S. territories is from “other petroleum,” there is a degree of uncertainty about the correct emissions factor to be used in this area, as well as the reliability of underlying data.

Data Sources

1980-1999: Energy Information Administration, *International Energy Annual*, DOE/EIA-0219 (Washington, DC, various years), and the International Energy Database (March 2000). 2000: EIA estimate.

Table A4. U.S. Territories Primary Energy Consumption (Btu), 1990, 1992-2000 (Quadrillion Btu)

Territory	1990	1992	1993	1994	1995	1996	1997	1998	1999	P2000
Puerto Rico	0.30	0.33	0.35	0.36	0.35	0.34	0.33	0.35	0.35	0.38
Virgin Islands, U.S.	0.12	0.12	0.12	0.12	0.19	0.16	0.20	0.26	0.28	0.29
American Samoa	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Guam	0.03	0.04	0.05	0.07	0.05	0.04	0.05	0.04	0.05	0.05
Hawaiian Trade Zone	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
U.S. Pacific Islands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wake Island	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Total	**0.47**	**0.52**	**0.55**	**0.58**	**0.62**	**0.57**	**0.61**	0.68	**0.71**	0.75

*Less than 5 trillion Btu.
P = preliminary data.
Notes: Data in this table are revised from the data contained in the previous EIA report, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99) (Washington, DC, October 2000).
Sources: Energy Information Administration, *International Energy Annual*, DOE/EIA-0219 (various years), and unpublished data included in "Other" countries in the Asia/Pacific region. Data are shown in tables of "Apparent Consumption of Petroleum Products." Data for 2000 based on unpublished preliminary information.

International Bunker Fuels

Emissions Sources

The term “international bunker fuels” refers to fuels sold to and consumed by air or marine vessels engaging in international transport activities. By convention, trade statistics treat the sale of bunker fuels as a form of export by the selling country, because the purchaser promptly hauls the fuel outside national boundaries. This convention is followed by organizations that prepare international energy statistics, such as the United Nations and the International Energy Agency.

Bunker fuels, however, are an export without a corresponding import, because the purchasing vessel generally combusts the fuel during transport. EIA energy statistics, which are based on domestic sales of products, treat bunker fuels sales in the same manner as the sale of other fuels, i.e. as domestic energy consumption. Therefore, carbon emissions from bunker fuels are already incorporated in the domestic energy consumption statistics of the United States, primarily as transportation-related consumption of residual and distillate fuel oil by cargo and passenger vessels and kerosene-based jet fuel by commercial aircraft. Table A5 shows U.S. international bunker fuel usage. Beginning with the 1999 data year, we have included estimates for military bunker fuels that make up about 10 percent of the total category.

Estimation Methods

Carbon coefficients are applied to annual consumption estimates for each of the relevant international bunker fuels, namely residual and distillate fuel oil to account for international marine bunkers, and kerosene-based jet fuel for international aviation bunkers. It is assumed that 99 percent of the fuel is combusted. Consumption estimates for distillate and residual fuel oil are each taken as the sum of oil laden on American and foreign ocean-going vessels in the United States. Since the data available for jet fuel consumption by U.S. air carriers reflects total fuel consumed on international routes, EIA estimates assume that domestic fuel purchases for outgoing international flights are 50 percent of this total. Jet fuel consumption by foreign air carriers fueled in the United States are based on the share of total expenses by these air carriers in U.S. ports that account for fuel and oil purchases, multiplied by the average annual price of jet fuel in U.S. ports. The estimate of military bunker fuels is obtained from the EPA inventory of the previous year. The 1999 estimate is used as a proxy for 2000 emissions.

Data Sources

Distillate and Residual Fuels (1980-1987): Energy Information Administration, *International Energy Annual*, DOE/EIA-0219 (Washington, DC, various years). (1988-2000): U.S. Department of Commerce, Bureau of the Census, Foreign Trade Division, “Report of Bunker Fuel Oil Laden on Vessels Cleared for Foreign Countries” (unpublished, various years); EIA estimate. Jet Fuels (1980-1987): Oak Ridge National Laboratory, *Transportation Energy Data Book* (Oak Ridge, TN, various years). (1988-2000): U.S. Department of Commerce, Bureau of Economic Analysis, unpublished BE-36 survey data (various years); Air Transportation Association, *Monthly Fuel Cost and Consumption* (various years), web site www.air-transport.org/public/industry/16.asp. Military Bunker Fuels: U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-1999* (Washington, DC 20460) April 2001.

Table A5. Consumption and Carbon emissions from International Bunker Fuels Supplied in the United States, 1990,1992-2000

Item	1990	1992	1993	1994	1995	1996	1997	1998	1999	P2000
Carbon Emissions (MMTCE)										
Marine Bunkers										
Distillate	1.7	1.5	1.7	1.4	1.6	1.2	1.2	1.7	0.8	0.8
Residual	15.2	14.3	11.4	11.2	11.1	11.4	12.2	12.7	10.4	9.4
Total Marine	*16.9*	*15.8*	*13.0*	*12.6*	*12.7*	*12.7*	*13.4*	*14.4*	*11.3*	*10.2*
Aviation Bunkers										
US Carriers	5.0	5.3	5.3	5.5	5.7	6.0	6.3	6.6	6.8	7.1
Foreign Carriers	5.3	5.6	5.8	6.0	6.6	6.8	7.6	7.6	8.5	7.8
Total Aviation	*10.4*	*11.0*	*11.1*	*11.5*	*12.4*	*12.8*	*13.9*	*14.2*	*15.3*	*14.9*
Total	27.3	26.7	24.2	24.1	25.1	25.4	27.3	28.6	26.6	25.1
Internat'l Bunker Fuels Consumed (Quadrillion Btu)										
Marine	0.8	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.5	0.5
Aviation	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8
Total	1.3	1.3	1.2	1.2	1.2	1.3	1.4	1.4	1.3	1.3

P = preliminary data.

Source: Distillate and Residual Fuels (1980-1987): Energy Information Administration, International Energy Annual, DOE/EIA-0219 (Washington, DC). (1988-2000); U.S. Department of Commerce, Bureau of the Census, Foreign Trade Division, "Report of Bunker Fuel Oil Laden on Vessels Cleared for Foreign Countries", (Unpublished). Jet Fuels (1980-1987): Oak Ridge National Laboratory, Transportation Energy Data Book (Oak Ridge, TN, various years). (1988-2000): U.S. Department of Commerce, Bureau of Economic Analysis, Unpublished BE-36 survey data (various years). Air Transportation Association, Monthly Fuel Cost and Consumption (various years), see web site http://www.air-transport.org/public/industry/31.asp

Other Carbon Dioxide Emissions

Other carbon dioxide emissions include emissions from energy production and industrial emissions that are not caused by the combustion or feedstock use of commercial fossil fuels. These emissions typically are created either by the combustion of waste products containing fossil carbon (natural gas flaring) or by chemical reactions with carbon-containing minerals (for example, calcining sodium carbonate [limestone] to make lime or cement).

Energy Production

Emissions Sources

U.S. energy production also generates small volumes of carbon dioxide emissions. The two principal sources are the flaring of natural gas and the venting of carbon dioxide produced in conjunction with natural gas.[8] When a field is developed for petroleum extraction, any natural gas associated with that field may be flared if its use is not economically justifiable. This is typically the case for remote sites or when the gas is of poor quality or minimal volume. During natural gas production, flaring may be used for disposal of waste products (e.g., hydrogen sulfide), capacity testing, or as a result of process upsets.

Emissions from the second source, carbon dioxide produced in conjunction with natural gas, occur during production activities. Natural gas is actually a mixture of several different gases including carbon dioxide. If the carbon dioxide content of natural gas is large enough to reduce the heating value of the gas below the specification for pipeline gas (870 Btu per standard cubic foot), the carbon dioxide is typically extracted by amine scrubbing. The extracted carbon dioxide generally is released to the atmosphere.

Estimation Methods

The method for estimating emissions from natural gas flaring is based on the volume of vented and flared gas reported to EIA (assuming that all gas is flared). To calculate carbon emissions, the figures are aggregated, converted into Btu, and then multiplied by an emissions coefficient of 14.92 million metric tons of carbon per quadrillion Btu.

As estimates presented in Chapter 2 indicate, natural gas flaring is a minor source of emissions, accounting for only about 2 to 5 million metric tons of carbon annually. There is some uncertainty associated with this estimate, given that operators in the field are not required to meter gas that is vented or flared.

The carbon dioxide produced in conjunction with natural gas is estimated by multiplying regional natural gas production data by regional carbon dioxide contents from a Gas Research Institute (GRI) study. The estimates of carbon dioxide emitted during transmission and distribution are derived by multiplying pipeline and end-use consumption data by the carbon dioxide content of natural gas delivered to consumers from a second GRI study. Emissions associated with production activities are calculated by subtracting consumption-related emissions from the total carbon dioxide initially produced. For 1999 and 2000 the 1998 value was moved by production of dry gas in quadrillion Btu as it appears in Table 1.3 of the *Monthly Energy Review July 2001*.

Data Sources

Flaring (1980-1999): Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131 (Washington, DC, various years). (2000): *Natural Gas Monthly*, DOE/EIA-0130(2000/08) (Washington, DC, August 2001). Carbon Dioxide Produced with Natural Gas: Composition (1980-1998): Gas Research Institute, *Chemical Composition of Discovered and Undiscovered Natural Gas in the United States: 1993 Update*, GRI-93/0456.1; Gas Research Institute, *Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States*, GRI-92/0123. Production (1980-1996): Dwight's Energy Data Lease/Well Production File. (1997-1998): Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131 (Washington, DC, 1999). (1999, 2000) Energy Information Administration, *Monthly Energy Review*, DOE/EIA-035(2001/07) (Washington, DC, July 2001). Transmission and End-Use Consumption (1980-1998):

[8]See discussion of carbon dioxide manufacture for the treatment of vented carbon dioxide.

Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131 (Washington, DC, various years). (1999): Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000).

Industrial Processes

In addition to energy-related emissions, carbon dioxide is also produced during certain industrial processes. The primary source of industrial emissions is the calcination of limestone ($CaCO_3$) to create lime (CaO). These two compounds are basic materials in a variety of manufacturing processes, particularly cement, iron and steel, and glass. Other sources of industrial emissions include the production and use of soda ash (Na_2CO_3), the manufacture of carbon dioxide, and aluminum production.

For this source category, emissions estimates are based on the compound used in the industrial process. Table A6 shows activity data for industrial processes. By multiplying the amount of production or consumption of the compound by a carbon coefficient (the relative amount of carbon in that compound), a process-specific estimate is derived. During the period 1990 through 2000, carbon dioxide emissions from industrial sources have ranged from 16 to 19 million metric tons of carbon annually. Each industrial process, emissions source, and estimation method is discussed below.

Cement Manufacture

More than half (58 percent) of the carbon dioxide emissions from industrial sources originate from cement manufacturing (see Chapter 2).

Emissions Sources. Four basic materials are required to make cement: calcium, silicon, aluminum, and iron. Substrates of these materials are ground into a powder and heated in a kiln. While in the kiln, limestone (the predominant source of calcium) is broken down into carbon dioxide and lime. The carbon dioxide is driven off into the atmosphere. After the kilning process has been completed, cement clinker is left.

Estimation Methods. One mole of calcined limestone produces one mole of carbon dioxide and one mole of lime. Since virtually all of the lime produced is absorbed into the clinker, the lime content of clinker is assumed to be representative of the amount of carbon dioxide emitted. In order to estimate emissions from cement manufacture, a carbon coefficient must be calculated. EIA has adopted the IPCC recommendation that 64.6 percent of cement clinker is lime.[9] Multiplying this lime content factor by the ratio of carbon produced to lime produced yields the coefficient for cement clinker. A separate coefficient is necessary for estimating emissions from the additional lime used to produce masonry cement. In this case, the amount of lime not accounted for as clinker is assumed to be 3 percent.[10] This factor is then multiplied by the same production ratio of carbon to lime, generating the carbon coefficient for masonry cement. It should also be noted that during clinker production, some of the clinker materials remain in the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). The carbon dioxide emissions attributable to the calcinated portion of the CKD are not accounted for by the clinker production emission factor. In keeping with the IPCC/OECD/IEA 1999 draft meeting report on emissions from industrial processes and the new gases (appearing in *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories)*, EIA estimates that an additional increment of carbon dioxide emissions from clinker production equal to 2-percent of direct emissions from clinker production are attributable to cement kiln dust.

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[9]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 2.6,www.ipcc.ch/pub/guide.htm

[10]U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999* (Washington, DC, April 2001), p. 3-5.

Table A6. Production Data for U.S. Carbon Dioxide Emissions from Industrial Sources, 1990,1992-2000
(Thousand Metric Tons)

Source	1990	1992	1993	1994	1995	1996	1997	1998	1999	P2000
Cement Clinker	63,326	62,184	65,745	69,787	69,983	70,361	72,686	74,523	76,003	78,500
Masonry Cement	2,911	2,806	2,962	3,613	3,603	3,469	3,634	3,989	4,000	5,000
Lime Produced	15,832	16,199	16,700	17,400	18,500	19,200	19,700	20,100	19,600	20,100
Limestone in Iron Smelting	3,955	3,098	2,561	2,538	2,615	2,538	2,549	2,477	2,379	2,600
Limestone in Steelmaking	682	612	1,087	1,225	1,126	949	750	798	612	1,029
Limestone in Glass	272	354	439	680	754	450	203	443	443	443
Limestone in FGD	4,369	4,479	4,274	4,621	5,815	6,125	6,595	6,322	6,835	6,835
Limestone in Dolomite Manufacture	986	641	549	526	428	691	673	654	295	295
Soda Ash Production (from Trona)	8,147	8,269	8,056	8,111	9,167	9,056	9,500	9,167	8,833	8,722
Soda Ash in Glass	3,177	3,082	3,095	3,150	3,130	3,040	3,130	3,220	3,270	3,270
Soda Ash in FGD	179	156	146	191	211	206	295	191	210	210
Sodium Silicate	740	827	913	914	1,091	1,002	1,101	1,096	948	1,075
Sodium Tripolyphosphate	451	419	419	419	419	419	419	205	181	181
Aluminum Manufacture	4,048	4,042	3,695	3,299	3,375	3,577	3,603	3,713	3,779	3,700
Copper Primary Smelting	1,577	1,710	1,790	1,840	1,930	2,010	2,070	2,140	1,890	1,610

P = preliminary data.
Sources: U.S. Department of the Interior, United States Geological Survey, *Mineral Commodity Summaries* (Washington, DC, various years). *Cement Annual Report* (Washington, DC, various years). *Soda Ash Annual Report* (Washington, DC, various years) (soda ash production calculated from quantity of trona ore production). *Crushed Stone Annual Report* (Washington, DC, various years). *Iron and Steel Annual Report* (Washington, DC, various years). *Copper Annual Report* (Washington, DC, various years). *Aluminum Annual Report* (Washington, DC, various years). Chemical Manufacturers Association, *U.S. Chemical Industry Statistical Handbook 1999* (Washington, DC, August 1999). Energy Information Administration unpublished survey data, *Steam Electric Plant Operation and Design Report, Form EIA-767* (Washington, DC, various years). Freedonia Group, Inc., *Carbon Dioxide*, Business Research Report B286 (Cleveland, OH, November 1991), and *Carbon Dioxide*, Industry Study 564 (Cleveland, OH, February 1994). American Iron and Steel Institute, *Annual Statistical Report* (Washington, DC, various years).

Lime Manufacture

Lime is an important chemical with a variety of industrial, chemical, and environmental applications.

Emissions Sources. Lime production involves three main stages: stone preparation, calcination, and hydration. Carbon diox ide is generated during the calcination stage, when limestone is roasted at high temperatures, just as it is released during clinker production. The carbon dioxide is driven off as a gas and normally exits the system with the stack gas.

Estimation Methods. Based on the ratio of the molecular weight of carbon dioxide to the weight of calcium carbonate, EIA assumes that 785 metric tons of carbon dioxide, or 214 metric tons of carbon, are released for every 1,000 metric tons of lime produced. This factor is applied to annual levels of lime manufacture to estimate potential emissions. EIA does not account for the instances in which the carbon dioxide is recovered or reabsorbed. Representatives of the National Lime Association believe that 10 to 20 percent of the carbon dioxide emitted in lime manufacture is recovered for industrial use or reabsorbed from the atmosphere by chemical reactions induced by the use of lime.

Limestone Consumption

These are basic raw materials used by a wide variety of industries, including the construction, agriculture, chemical, and metallurgical industries.

Emissions Sources. Limestone (including dolomite) can be used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems in utility and industrial plants, as a raw material in glass manufacturing, or as an input for the production of dead-burned dolomite. Limestone is heated during these processes, generating carbon dioxide as a byproduct.

Estimation Methods. Assuming that limestone has a carbon content of 12 percent and dolomite 13.2 percent, EIA applies the appropriate factor to the annual level of consumption in the iron smelting, steelmaking, and glass manufacture industries, and in flue gas desulfurization systems that use this sorbent. This amounts to 120 metric tons of carbon for every 1,000 metric tons of limestone consumed, or 132 metric tons of carbon for every 1,000 tons of dolomite consumed (when dolomite is distinguished in the data). In the case of limestone (including dolomite) used in flue gas desulfurization units, the estimate of carbon emitted was adjusted based on the application of a capacity utilization rate from the calcination process of sorbents used, typically limestone (including dolomite). According to information obtained in May 1999 from the U.S. Geological Survey regarding the characterization of limestone consumed in fluidized-bed combustion systems and flue gas desulfurization units, the utilization rate of calcium obtained from the calcination process, ranges from approximately 30 to 40 percent.

Soda Ash Manufacture and Consumption

Commercial soda ash (sodium carbonate) is used in many familiar consumer products, such as glass, soap and detergents, paper, textiles, and food.

Emissions Sources. Two methods are used to manufacture natural soda ash in the United States. The majority of production comes from Wyoming, where soda ash is manufactured by calcination of trona ore in the form of naturally occurring sodium sesquicarbonate. For every mole of soda ash created in this reaction, one mole of carbon dioxide is also produced and vented to the atmosphere. The other process used to manufacture soda ash is carbonation of brines; however, the carbon dioxide driven off in this process is captured and reused.

Once manufactured, most soda ash is consumed in glass and chemical production. Other uses include water treatment, flue gas desulfurization, soap and detergent production, and pulp and paper production. As soda ash is processed for these purposes, additional carbon dioxide may be emitted if the carbon is oxidized. Because of the limited availability of specific information about such emissions, only certain uses of soda ash are considered in this report. Sodium silicate and sodium tripolyphosphate are included as chemicals manufactured from soda ash and components of detergents.

Estimation Methods. For soda ash manufacture, in order to ensure that carbon dioxide from the carbonation of brines is not included in emissions estimates, the calculations in this report are derived solely from trona ore production figures. Approximately 1.8 metric tons of trona ore are required to yield 1 metric ton of soda ash. This amounts to 97 metric tons of carbon dioxide for every 1,000 tons of trona ore produced annually. For soda ash consumption, EIA applies a factor of 113 metric tons of carbon for every 1,000 metric tons of soda ash consumed in glass manufacturing or in flue gas desulfurization.

Carbon Dioxide Manufacture

Emissions Source. Carbon dioxide is produced from a small number of natural wells and as a byproduct of chemical (i.e., ammonia) manufacturing. The Freedonia Group has determined that, in the United States, there is an 80 percent to 20 percent split between carbon dioxide produced as a byproduct and carbon dioxide produced from wells.[11] Emissions of byproduct carbon dioxide are incorporated into the natural gas energy consumption estimates as nonfuel, nonsequestered carbon and therefore are not included here to avoid double counting. Most carbon dioxide produced from wells is injected back into the ground for enhanced oil recovery. This process sequesters the carbon dioxide, at least in the short run. Conceptually, only carbon dioxide produced from wells and diverted to industrial use is emitted to the atmosphere.

Estimation Methods. The Freedonia Group estimates that non-sequestering industrial use of carbon dioxide resulted in emissions of 1.3 million metric tons of carbon in 1993.[12] If 20 percent of this industrial use is supplied by wells, emissions can be estimated at 0.26 million metric tons of carbon. Based on the Freedonia report, the 2000 estimate is calculated by assuming an annual 4.2-percent increase, implying emissions of 0.35 million metric tons of carbon.

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[11]The Freedonia Group, Inc., *Carbon Dioxide*, Business Research Report B286 (Cleveland, OH, November 1991), p. 46.
[12]The Freedonia Group, Inc., *Carbon Dioxide*, Industry Study 564 (Cleveland, OH, February 1994), p. 37.

Aluminum Manufacture

Aluminum is an element used in alloys. Because it is light in weight, malleable, and not readily corroded or tarnished, it is used as a principal material for kitchen utensils, aircraft, some automobiles, bicycles, and other manufactured products. The United States is a major producer of aluminum and also an importer, depending on market conditions.

Emissions Sources. As part of the primary aluminum smelting process, alumina (aluminum oxide, Al_2O_3) is vaporized by a powerful electric current. Emissions from the electricity used to generate the current are included with emissions from industrial electricity consumption and are not counted separately. The current also vaporizes a carbon "sacrificial anode," typically manufactured from petroleum coke. This is a nonsequestering nonfuel use of a fossil fuel. To avoid double counting, 50 percent of nonfuel use of petroleum coke is carried as "sequestering." Thus, process emissions from aluminum smelting can be considered as a deduction from the sequestering portion of nonfuel use of petroleum coke.

Estimation Methods. The 1994 MECS indicated that nonfuel use of fuels by aluminum smelters (SIC 3334) totaled 40 trillion Btu in 1994.[13] The composition of nonfuel use by fuel type has been withheld for confidentiality purposes, but it is probable that most of the 40 trillion Btu consists of petroleum coke, which would imply an emissions factor of about 0.338 metric tons of carbon per metric ton of aluminum smelted (0.04 quadrillion Btu of coke × 27.85 million metric tons of carbon per quadrillion Btu / 3.295 million metric tons of aluminum smelted in 1994). EIA now uses an emissions factor of 0.4 metric tons carbon per metric ton of aluminum smelted, which is at the low end of Abrahamson's range and also equals the mass balance for a "typical" aluminum smelter from another source.[14]

Municipal Solid Waste

A portion of the municipal solid waste(MSW) that is burned contains plastics. The carbon that goes into plastics is subtracted from the inventory. Therefore, when those plastics are burned they must be accounted for as additions to the atmosphere of carbon. The U.S. EPA accounted for MSW for the first time in the 1998 official inventory. This document uses the EPA estimate for 1990 through 1999 and uses the 1999 estimate for 2000. This number is currently reported under "waste" as it includes for example emissions from the burning of toxic wastes in addition to the MSW, much of which is burned in the generation of electrical energy.

Data Sources for Industrial Processes

The U.S. Geological Survey reports listed below can be found on the Internet at minerals.er.usgs.gov/pubs/commodity.

Cement and Clinker Production (1980-1999): U.S. Department of the Interior, U.S. Geological Survey, *Cement Annual Report* (Washington, DC, various years). **(2000):** U.S. Department of the Interior, U.S. Geological Survey, *Mineral Commodity Summaries* (Washington, DC, 2001).

Lime Manufacture: (1980-2000): U.S. Department of the Interior, U.S. Geological Survey, *Mineral Commodity Summaries* (Washington, DC, various years).

Limestone Consumption in Iron Smelting, Steelmaking, and Glass Manufacture: (1980-1999): U.S. Department of the Interior, U.S. Geological Survey, *Crushed Stone Report* (Washington, DC, various years). **(2000):** EIA estimate. **Limestone Consumption in Flue Gas Desulfurization: (1980-1999):** Energy Information Administration, unpublished survey data, Form EIA-767, "Steam Electric Plant Operation and Design Report" (Washington, DC, various years). **(2000):** EIA estimate.

Soda Ash Manufacture and Soda Ash Consumption in Glass Making (1980-2000): U.S. Department of the Interior, U.S. Geological Survey, *Soda Ash Report* (Washington, DC, various years). **Soda Ash Consumption in Flue Gas**

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[13]Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997), Table A3, p. 49.

[14]Drexel University Project Team, *Energy Analysis of 108 Industrial Processes* (Lilburn, GA: The Fairmont Press, 1996), p. 282.

Desulfurization (1980-1999): Energy Information Administration, unpublished survey data, Form EIA-767, "Steam Electric Plant Operation and Design Report" (Washington, DC, various years). **(2000):** EIA estimate. **Sodium Silicate and Sodium Tripolyphosphate: (1980-1996):** Chemical Manufacturers Association, *U.S. Chemical Industry Statistical Handbook 1998* (Washington, DC, September 1998), pp. 37-38. **(1997-2000):** data published by the U.S. Department of Commerce, Bureau of the Census, in its annual and quarterly *Current Industrial Reports* on inorganic materials.

Carbon Dioxide: Freedonia Group, Inc., *Carbon Dioxide*, Business Research Report B286 (Cleveland, OH, November 1991), and *Carbon Dioxide*, Industry Study 564 (Cleveland, OH, February 1994).

Aluminum (1980-2000): U.S. Department of the Interior, U.S. Geological Survey, *Aluminum Report* (Washington, DC, various years).

Municipal Solid Waste (1990-1999, 2000 estimate): U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999* (Washington, DC, April 2001).

Methane

Energy Sources

Coal Mining

Emissions Sources

As coal is formed from organic material by natural chemical and physical processes, methane is also produced. The methane is stored in the pores (open spaces) of the coal itself and in cracks and fractures within the coalbed. As coal is mined, the pressure surrounding the stored methane decreases, allowing much of it to be released into the operating coal mine (in the case of an underground mine) or into the atmosphere (in the case of a surface mine). The methane remaining in the coal pores is emitted when the coal is transported and pulverized for combustion. There are five avenues for methane emissions from coal mines:

- **Ventilation Systems in Underground Mines.** Methane in concentrations over 5 percent is explosive and presents a mortal danger to coal miners. To meet safety standards set by the Mine Safety and Health Administration (MSHA) requiring levels of methane concentration to be maintained well below the 5-percent threshold, mine operators use large fans to provide a steady airflow across the mine face and ventilate the mine shaft. Typically, these ventilation systems release substantial quantities of methane in the fan exhaust.

- **Degasification Systems in Underground Mines.** When the volume of gas in underground mines is too high to be practically reduced to safe levels by standard ventilation techniques, degasification systems are employed. Degasification may take place before mining or may take the form of gob-wells or in-mine horizontal boreholes. Methane captured by degasification systems may be vented, flared, or recovered for energy.

- **Surface Mines.** Because coal mined from the surface has formed at lower temperature and pressure than coal from underground mines, its methane content is lower. Further, because the coal is located near the surface, methane has had ample opportunity to migrate to the atmosphere before mining. Thus, while methane emissions from surface mines are heterogeneous in nature, they are systematically smaller than emissions from underground mines.

- **Post-Mining Emissions.** Methane that remains in coal pores after either underground or surface mining will desorb slowly as the coal is transported (typically by train) to the end user. Because coal that is consumed in large industrial or utility boilers is pulverized before combustion, methane remaining in the coal pores after transport will be released prior to combustion.

- **Methane Recovery for Energy.** In some cases (for example, in some mining degasification systems), methane is emitted from coal mines in sufficiently high volumes and concentrations to permit commercial recovery of the gas as either pipeline gas, power generation fuel, or for mine site uses. Because coal mine methane recovered commercially is combusted, the quantities recovered are subtracted from estimates of total coal mine methane emissions.

Estimation Methods

Ventilation Systems in Underground Mines. Emissions from this source are segregated into two classes: emissions from "gassy" mines and emissions from "nongassy" mines.[15] Because methane concentrations and airflows in gassy mines are carefully monitored by the MSHA, a fairly reliable set of data can be derived for emissions from ventilation systems in gassy mines. Prior to 1993, MSHA data are available for only a subsample of years (1980, 1985, 1988, 1990, 1993). Thus, EIA developed a methodology that uses available in conjunction with coal production data to develop emissions factors per ton of coal mined on a basin-by-basin level (Table A7).[16] Emissions factors for nonsample years are interpolated. The resulting emissions factors are then multiplied by production data (see Table A8) to estimate emissions from this source for the period through 1998. For 1999 and 2000 ventilation emissions from "gassy" mines are estimated based directly on a compilation of MSHA data by the U.S. EPA Office of Air and Radiation.

Table A7. Methane Emissions Factors for Gassy Underground Coal Mines, 1990-1998

Gassy Mines	Units	1990	1991	1992	1993	1994	1995	1996	1997	1998
Northern Appalachia	CFD/Ton	1.01	1.09	1.17	1.24	0.79	0.8	0.81	0.85	0.86
Central Appalachia	CFD/Ton	1.45	1.42	1.39	1.35	1.17	1.17	1.17	0.90	0.81
Warrior	CFD/Ton	4.62	4.48	4.34	4.2	5.31	4.63	3.94	3.62	3.91
Illinois	CFD/Ton	0.44	0.46	0.48	0.49	0.47	0.485	0.5	0.48	0.43
Western	CFD/Ton	1.51	1.33	1.15	0.96	1.11	0.98	0.85	0.99	0.86

Sources: Coal Production numbers from Energy Information Administration Form 7-A, *Coal Production,* DOE/EIA-0118 (Washington, DC, various years), and *Coal Industry Annual*, DOE/EIA-0584, Ventilation data for 1990 and 1993 provided by G. Finfinger, U.S. Department of Interior, Bureau of Mines, Pittsburgh Research Center. Ventilation data for 1994-1998 provided by U.S. Environmental Protection Agency, Coalbed Methane Outreach Program.

Table A8. U.S. Coal Production by Type of Mining and Basin, 1990-1998
(Million Metric Tons)

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Underground									
Northern Appalachia	95.5	93.5	92.5	69.7	90.8	88.6	96.5	101.7	105.9
Central Appalachia	178.6	165.3	164.1	149.1	155.0	151.0	155.9	161.2	155.4
Warrior	15.9	15.5	14.5	14.1	13.1	16.0	16.5	16.8	15.7
Illinois	62.8	63.5	66.4	50.8	62.8	62.6	60.9	58.9	58.7
Western	31.3	30.8	31.1	34.1	40.3	40.8	41.6	43.0	43.3
Total	384.2	368.6	368.6	317.8	362.0	359.0	371.4	381.5	378.9
Surface	548.3	534.0	535.4	539.1	575.4	577.5	593.2	607.0	634.7
Total All Mines	933.4	903.4	904.7	857.5	937.4	936.8	965.0	988.5	1014.0

P = preliminary data. NA = data not available.

Sources: Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years).

[15]Gassy mines are defined as those underground coal mines with measured emissions from ventilation exhaust in excess of 100,000 cubic feet of methane per day.

[16]For purposes of this analysis, the Northern Appalachia basin includes Pennsylvania, Northern West Virginia, Maryland, and Ohio; the Central Appalachia basin includes Eastern Kentucky, Virginia, Southern West Virginia, and Tennessee; the Warrior basin includes Alabama; the Illinois basin includes Illinois, Indiana, Western Kentucky, Iowa, and Oklahoma; and the Western basin includes Colorado, New Mexico, Utah, and Wyoming.

Emissions from nongassy mines make up less than 2 percent of all emissions from underground mines.[17] Basin-level emissions factors for nongassy mines were established by dividing 2 percent of each basin's estimated emissions from nongassy mines for 1988 by that year's production levels. The resulting emissions factors are applied to annual production data for the period through 1998. For 1999 and 2000, emissions from nongassy mines are based on calculations from the U.S. EPA Office of Air and Radiation.

Degasification Systems in Underground Mines. Degasification emissions are not monitored by any regulatory agency. Where degasification does occur, the method of disposition may not be tabulated. Estimated emissions from degasification systems during the period 1993 through 1999 are based on data collected by the EPA's Office of Air and Radiation, Coalbed Methane Outreach Program. For years prior to 1993, emissions from degasification systems are estimated by multiplying annual production in mines known to have degasification systems in place by a per-ton emissions factor. For 2000, emissions from degasification systems were assumed to have remained constant from 1999 levels.

Surface Mines. Emissions from U.S. surface mines have not been systematically measured. However, studies on surface coal mines in the United States, England, France, and Canada suggest a range of 0.3 to 2.0 cubic meters per metric ton of coal mined.[18] This report adopts the central value of that range and multiplies it by U.S. surface coal production.

Post-Mining Emissions. Like emissions from surface mines, post-mining emissions are not measured systematically. Thus, global average emissions factors must be applied. Post-mining emissions for coal mined from the surface are estimated to be very low, between 0.0 and 0.2 cubic meters per metric ton of coal mined. In contrast, post-mining emissions from underground coal are estimated to be more significant, between 0.9 and 4.0 cubic meters of methane per metric ton of coal mined.[19] The central values of these ranges are adopted and multiplied by annual production data for this report.

Methane Recovery for Energy. Methane recovery for energy is restricted to a small sample of mines that typically meter their gas sales. Thus, total methane recovery can be estimated from the volume and heat content of sales. The EIA adopts a time series of methane recovery prepared by the EPA Coalbed Methane Outreach Program for all years through 1999. For 2000, methane recovery levels are assumed to remain constant from 1999 levels.

Data Sources

Ventilation Systems in Underground Mines. Coal mine ventilation data for the gassiest U.S. mines were drawn from a database prepared by the Department of Interior's Bureau of Mines for the years 1980, 1985, 1988, 1990, and 1993. Ventilation data for 1994-2000 were obtained from the EPA, Climate Protection Division, Coalbed Methane Outreach Program. Coal production data are reported to EIA on Form EIA-7A, "Coal Production Report." Basin-level emissions for nongassy mines in 1988 were calculated by the EPA's Office of Air and Radiation, in *Anthropogenic Methane Emissions in the United States: Estimates for 1990* (Washington, DC, April 1993), pp. 3-19–3-24.

Degasification Systems in Underground Mines. Data on drainage from degasification systems from 1993 through 1999 are from the EPA's Office of Air and Radiation, Climate Protection Division, Coalbed Methane Outreach Program. Emissions factors for this source are derived from estimates of 1988 emissions from degasification systems prepared by the EPA's Office of Air and Radiation, in *Anthropogenic Methane Emissions in the United States: Estimates for 1990* (Washington, DC, April 1993), pp. 3-19B–3-24. Annual production figures are reported to EIA on Form EIA-7A, "Coal Production Report."

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[17]M.A. Trevits, G.L. Finfinger, and J.C. LaScola, "Evaluation of U.S. Coal Mine Emissions," in Society for Mining, Metallurgy and Exploration, *Proceedings of the Fifth U.S. Mine Ventilation Symposium* (Littlejohn Co., 1991), p. 2.

[18]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), pp. 1.98-1.112,www.ipcc.ch/pub/guide.htm

[19]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), pp. 1.98-1.112,www.ipcc.ch/pub/guide.htm

Surface Mines. Emissions factors for surface mines are found in Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997),www.ipcc.ch/pub/guide.htm Coal production data are reported to EIA on Form EIA-7A, "Coal Production Report."

Post-Mining Emissions. Emissions factors for post-mining emissions are found in Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997),www.ipcc.ch/pub/guide.htm Coal production data are reported to EIA on Form EIA-7A, "Coal Production Report."

Methane Recovery for Energy. Methane recovery estimates the EPA's Office of Air and Radiation, Climate Protection Division, Coalbed Methane Outreach Program.

Natural Gas Production, Processing, and Distribution

Emissions Sources

Because methane is the principal constituent of natural gas (representing about 95 percent of the mixture), releases of natural gas result in methane emissions. Methane emissions can be grouped into three categories: (1) fugitive or unintentional leaks emitted from sealed surfaces such as pipelines, gaskets, and flanges; (2) vented or intentional releases from process vents, maintenance blowdowns, and pneumatic devices; and (3) releases from incomplete combustion in compressor engines, burners, and flares.[20] The natural gas industry can be divided into four source segments:

- **Gas Production.** This segment consists of gas and oil wells, surface equipment to produce gas, and gathering pipeline. Leakage occurs from valves, meters, and flanges. Pneumatic valves release gas when they are reset. Gathering pipeline may be emptied for maintenance or may have fugitive emissions.

- **Gas Processing.** When gas is processed, liquefied petroleum gases and natural gasoline are removed for sale or further refining. Water is also removed, and gas is conformed to commercial pipeline quality and heat content. Methane is released during maintenance, via leaks, and during system upsets when sudden increases in pressure require a gas release or result in a system rupture.

- **Transmission and Storage.** High-pressure transmission pipelines transport natural gas from production fields and gas processing facilities to distribution pipelines. Natural gas may escape through leaky pipes and valves. Methane may be emitted as part of compressor exhaust. Gas is often stored near consumption centers to meet peak demand during periods of high consumption. These storage facilities emit methane in compressor exhaust and from dehydrators.

- **Distribution.** The pressure of gas received from the transmission system is lowered at the gate station and is forwarded to distribution pipeline for delivery to residential, commercial, and industrial consumers. Leaks may occur at gate stations, through leaky pipes, and at customer meters.

Estimation Methods

Estimates of emissions from the natural gas system are scaled to commonly available activity data such as number of wells in operation, miles of gathering pipeline, gas throughput, gas volumes processed, miles of transmission pipeline and miles of distribution pipeline. The activity data are multiplied by emissions factors derived from point-in-time

[20]National Risk Management Research Laboratory, *Methane Emissions From the Natural Gas Industry*, Vol. 2, Technical Report, GRI-94/0257.1 and EPA-600-R-96-08 (Research Triangle Park, NC, June 1996), p. 19.

emissions estimates for 1992 developed in a study sponsored jointly by the U.S. Environmental Protection Agency (EPA) and the Gas Research Institute (EPA/GRI).[21] The EPA/GRI study provides activity data and disaggregated emissions factors for 86 separate gas industry process components. In an effort to take advantage of this level of detail, this report estimates the number of each process component for the years 1990-2000. Each process component is scaled to a widely available metric, such as gas withdrawals or pipeline miles most related to the process activity. The derived activity data are then applied to the component emissions factor from the EPA/GRI report.

Data Sources

Natural Gas Systems. Emission factors and activity data for 1992 are from the joint EPA/GRI study: National Risk Management Research Laboratory, *Methane Emissions From the Natural Gas Industry*, Vol. 2, Technical Report, GRI-94/0257.1 and EPA-600-R-96-08 (Research Triangle Park, NC, June 1996). Activity data for all other years are scaled to data from the following sources: gas wellheads, gross gas withdrawals, gas processing and gas removed from storage can be found in EIA's *Natural Gas Annual* (various years); transmission and distribution pipeline mileage are published annually by the American Gas Association in *Gas Facts*.

Petroleum Systems

Emissions Sources

The vast preponderance of emissions from petroleum systems occur during crude oil exploration and production. Much smaller emissions occur during crude transportation and crude refining. Emissions from petroleum systems can be divided into four types: 1) vented emissions; 2) fugitive emissions; 3) combustion emissions and 4) upset emissions.

- vented emissions are intentional releases to the atmosphere by facility design or operational practice.
- fugitive emissions are accidental and often ongoing releases associated with a leak source within the system
- combustion emissions are the result of fuel use to drive compressors or flares
- upset emissions are typically the result of safety measures such as emergency pressure releases or oil platform shutdowns[22]

The largest single emissions source is the venting at crude oil storage tanks.

Estimation Methods

Estimates of emissions from petroleum systems are derived by multiplying emission factors for approximately 90 separate components of the petroleum system by an estimate of the total number of components on the national system. To produce a time-series of estimates, the number of components for 1990 - 2000 are scaled to readily available industry activity data such as number of oil wells, refinery input, and crude transported by pipeline, marine vessel or truck.

Data Sources

Emission factors are fromr U.S. Environmental Protection Agency, Office of Air and Radiation, Draft Report, *Estimates of Methane Emissions from the U.S. Oil Industry*. Activity data are from EIA's *Monthly Energy Review* (July, various years), EIA's *Petroleum Supply Annual* (various years), Oil and Gas Journal's *Worldwide Refining Issue and Pipeline Economics Issue*.

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[21]National Risk Management Research Laboratory, *Methane Emissions From the Natural Gas Industry*, Vol. 2, Technical Report, GRI-94/0257.1 and EPA-600-R-96-08 (Research Triangle Park, NC, June 1996), p. 19.

[22]U.S. Environmental Protection Agency, Office of Air and Radiation, *Estimates of Methane Emissions from the U.S. Oil Industry*, (Draft Report, Washington, D.C.)

Stationary Combustion

Emissions Sources

The principal products of fuel combustion are carbon dioxide and water vapor. When fuel combustion is incomplete, methane may also be released. The volume of methane released varies according to the efficiency and temperature of the combustion process. Most stationary sources are large, comparatively efficient boilers, such as those found in the industrial and utility sectors, and thus have low levels of methane emissions. However, a significant amount of wood is consumed in residential woodstoves and fireplaces, which are typically inefficient combustion chambers. Wood combustion in these devices produces most of the U.S. methane emissions from stationary sources.

Estimation Methods

An emissions factor based on fuel type (for example, coal, wood, natural gas) and combustion technology (for example, utility boiler, industrial boiler, woodstove) is applied to consumption data for each fuel and technology type.

Data Sources

Emissions coefficients for stationary fuel were obtained from the EPA's Office of Air Quality Planning and Standards, *Compilation of Air Pollutant Emission Factors*, AP-42, and Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), www.ipcc.ch/pub/guide.htm. Fuel consumption data were drawn from the Energy Information Administration, *State Energy Data Report 1997*, DOE/EIA-0214(99) (Washington, DC, September 1999) for 1980-1997; and *Monthly Energy Review*, DOE/EIA-0035(01/07) (Washington, DC, July 2001) for 1998-2000. Residential woodfuel consumption data were derived from EIA's *Annual Energy Review 2000*, DOE/EIA-0384(00) (Washington, DC, July 2001).

Mobile Combustion

Emissions Sources

Methane emissions from mobile combustion are, like those from stationary combustion, the result of incomplete fuel combustion. In automobiles, methane emissions result when oxygen levels in the combustion chamber drop below levels sufficient for complete combustion. The effects of incomplete combustion in automobiles may be moderated somewhat by post-combustion emissions controls, such as catalytic converters. Methane emissions are also generated by fuel combustion in other modes of transport. Other sources include aircraft, ships and locomotives, in addition to methane emissions from farm and construction equipment. There is, however, some evidence that jet airplane engines may consume ambient methane during flight, thereby reducing their net emissions.

Estimation Methods

Methane emissions from highway vehicles are estimated by applying emissions factors (per vehicle mile traveled) to vehicle use data. Research indicates that emissions rates differ among motor vehicles by vehicle type and by type of catalytic converter (associated with the vintage of the motor vehicle) for light duty vehicles. Consequently, EIA partitions vehicle use data by vehicle type (i.e. by passenger cars, light-duty trucks, buses, motorcycles, and heavy-duty trucks), as well as by motor vehicle vintage (model year) for passenger cars and light duty trucks. Due to improvements in technology and increasing stringency of environmental regulations, motor vehicle methane emissions have generally declined over time. For non-highway sources, emissions coefficients are applied directly to annual fuel consumption data.

Data Sources

Emissions factors for all vehicles are provided in Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris,

France, 1997),www.ipcc.ch/pub/guide.htm. EIA collected data on miles traveled in personal transportation vehicles (cars and light-duty trucks) as part of its triennial Residential Transportation Energy Consumption Survey (RTECS): Energy Information Administration, *Household Vehicles Energy Consumption 1994*, DOE/EIA-0464 (Washington, DC, July 1996, and previous years). This survey contains data for the years 1983, 1985, 1988, 1991, and 1994. Vehicle miles traveled for other years are estimated using weighted averages from survey data in conjunction with statistics on the U.S. fleet of cars and trucks by model year, provided by provided by the American Automobile Manufacturers Association*, AAMA Vehicle Facts and Figures* (Detroit, MI, various years) and by Ward's Communications Inc., *Ward's Automotive Yearbook* (Southfield, MI, 1999). Vehicle miles traveled for non-household vehicles, motorcycles, buses, and heavy-duty trucks were obtained from the U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics* (Washington, DC, various years), web site www.fhwa.dot.gov/ohim/ohimstat.htm.

Fuel consumption for ships, locomotives, farm and construction equipment is based on data from EIA's *Fuel Oil and Kerosene Sales*, DOE/EIA-0535 (Washington, DC, various years). Jet and piston-powered aircraft fuel consumption data are contained in the Energy Information Administration's *Petroleum Supply Annual*, DOE/EIA-0340 (Washington, DC, various years). Data on fuel consumption by recreational boats are taken from Oak Ridge National Laboratory, Center for Transportation Analysis, *Transportation Energy Data Book* (Oak Ridge, TN, various years), web site www-cta.ornl.gov/publications/tedb.html.

Landfill Methane Emissions

Emissions Sources

After organic wastes (e.g., food, paper, yard waste) are placed in landfills, they begin to decompose. Aerobic bacteria, consuming oxygen, convert organic material to carbon dioxide, heat, and water. When available oxygen is depleted, anaerobic bacteria, including methanogens, begin digesting the waste and producing methane. Methanogenic anaerobes are highly sensitive to temperature, pH, and moisture levels. Because U.S. sanitary landfills are essentially closed systems designed to minimize entry and exit of moisture, conditions within a landfill are largely a product of the composition of the waste it contains. Thus, methane is likely to be produced at different rates and volumes both across different landfills and within a single landfill.

The biogas produced in a landfill is typically between 50 and 60 percent methane. When emitted, biogas mixing with air can result in methane concentrations within the explosive range of 5 to 15 percent. Often, landfill operators put methane control systems in place to prevent migration of high concentrations to buildings. Methane captured by control systems may be vented to the atmosphere or flared, but it is also a potentially valuable energy resource. Where landfills produce steady, large volumes of methane and landfill gas-to-energy prices are competitive with other energy alternatives, recovered gas may be used as an energy resource. In most cases, the gas is converted to electricity and used for on-site energy needs or sold to local utilities. In some cases, the gas is transported via pipeline to a local end user.

Estimation Methods

Data on methane emissions from landfills are limited to those landfills with methane recovery systems in place. For more than 100 U.S. landfills with gas recovery systems in place, Thorneloe et al. measured or estimated methane emissions at 2.1 million metric tons for 1992.[23] Methane emissions from landfills without gas recovery systems have not been measured, and even the number of landfills is subject to considerable uncertainty. Emissions from a given landfill are largely the product of the composition of the waste it contains and an array of site-specific factors. Waste composition data on a landfill-specific basis are nonexistent; however, national-level waste flow and waste composition data are available, and their reliability has improved over time. Thus, for this report, all waste not disposed of in a landfill with measured emissions is treated as if it has flowed to one very large national landfill.

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[23]S.A. Thorneloe, M.R.J. Doorn, L.A. Stefanski, M.A. Barlaz, R.L. Peer, and D.L. Epperson, "Estimate of Methane Emissions From U.S. Landfills," Prepared for U.S. Environmental Protection Agency, Office of Research and Development (April 1994), p. 1087.

To estimate methane emissions from all waste not disposed of in a landfill with measured emissions, waste volumes are subjected to a slightly modified version of the EMCON Methane Generation Model.[24] This model divides the waste into three categories: readily decomposable, moderately decomposable, and slowly decomposable, each with its own set of emissions characteristics. The EMCON model provides both a high methane yield scenario and a low methane yield scenario. For each category of decomposable waste, a time lag until methane generation begins is estimated, as well as a time constant during which the methane yield of the waste is realized. The methane yield represents the total amount of methane that a given amount of waste will produce over its lifetime. For example, under a low methane yield scenario, slowly decomposing waste will begin producing methane after a 5-year lag and will continue emitting over a 40-year period. Table A9 shows the EMCON methane generation model parameters.

Waste flows were estimated from 1940 through 2000. Waste in place in the Nation's landfills was assumed to represent the waste stream for all previous years plus the current year's additions. The landfills examined by Thorneloe et al. contained 9.2 percent of the waste estimated to be in place in the Nation's landfills during 1992. This report assumes that the share of waste in these landfills and the share in all other landfills remained constant over time. Thus, the EMCON model was applied to 90.8 percent of the waste generated each year.

To estimate emissions from those landfills with measured data for 1992 but no data for other years, the EMCON model was recalibrated to produce the 2.1 million metric tons of measured emissions in 1992. The recalibrated model, with methane yields almost twice as large as the original, was then applied to 9.2 percent of the waste stream for all years. These much higher yields are not unexpected, as gas recovery systems are most economically employed in high-emitting landfills.

Table A9. EMCON Methane Generation Model Parameters

Waste Category	Decomposable Portion (Percent by Dry Weight)	Methane Yield (Cubic Feet per Pound)	Lag Time (Years)	Time Constant
High Yield (Default)				
Readily Decomposable	4.0	4.5	0.2	3
Moderately Decomposable	45.0	3.6	1.5	10
Slowly Decomposable	5.2	0.5	5.0	20
Low Yield (Default)				
Readily Decomposable	4.0	2.8	0.3	4
Moderately Decomposable	45.0	2.0	2.0	20
Slowly Decomposable	5.2	0.3	5.0	40
High Yield (Modified)				
Readily Decomposable	4.0	8.8	0.0	3
Moderately Decomposable	45.0	7.0	2.0	10
Slowly Decomposable	5.2	1.0	5.0	20
Low Yield (Modified)				
Readily Decomposable	4.0	5.4	0.0	4
Moderately Decomposable	45.0	3.8	2.0	20
Slowly Decomposable	5.2	0.6	5.0	40

Source: D. Augenstein, "The Greenhouse Effect and U.S. Landfill Methane," Global Environmental Change (December 1992), pp. 311-328.

Data Sources

Data on waste generated and landfilled for the period 1988 through 1999 (Table A9) were drawn from "Nationwide Survey: The State of Garbage in America," *Biocycle* (1988-2000). These data were not collected by *Biocycle* before 1988. Waste generated and landfilled for the period 1960 through 1987 was estimated from data produced by Franklin

[24]D. Augenstein, "The Greenhouse Effect and U.S. Landfill Methane," *Global Environment Change* (December 1992), pp. 311-328.

Associates. On behalf of the EPA's Office of Solid Waste and Emergency Response, Franklin Associates have estimated municipal solid waste (MSW) generated and landfilled for the years 1960 through 1997. See Franklin Associates, Ltd., *Characterization of Municipal Solid Waste in the United States*, Worksheets, 1992 update, Prepared for the U.S. Environmental Protection Agency, Municipal Solid and Industrial Solid Waste Division (July 1992) and U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, *Characterization of Municipal Solid Waste in the United States: 1998 Update*, EPA-530-S-99-021 (Washington DC, July 1999). In contrast to the *Biocycle* data, which include all waste going to landfills, including construction and demolition (C&D) waste and sludge, the Franklin data include only MSW going to landfills. For 2000, waste generation data were not yet available so 1999 estimates were scaled up by GDP growth of 4.1 percent to provide an estimate of waste generation in 2000. The volume of waste recycled or combusted rather than landfilled was assumed to have grown from 39% in 1999 to 40% in 2000.

Table A10. U.S. Solid Waste Generated and Landfilled, 1990-2000
(Million Metric Tons)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000P
Waste Generated	266.4	254.6	264.7	278.4	292.9	296.4	297.1	308.9	339.9	353.7	368.2
Waste Landfilled	205.2	193.6	190.6	197.7	196.3	186.8	184.2	188.5	207.4	215.8	221.0
Waste In Place	6868.7	7062.3	7252.9	7450.6	7646.9	7833.7	8017.9	8206.4	8413.7	8629.6	8850.6

Source: "Nationwide Survey: The State of Garbage in America," Biocycle (1988-2000).

In order to account for categories of waste other than MSW going to landfills between 1960 and 1987, an average ratio of waste generation estimated by *Biocycle* and waste generation estimated by Franklin Associates for 1988 through 1997 was calculated. The annual average ratio during this period was 1.47 to 1. Thus, all Franklin estimates for 1960 through 1987 were multiplied by 1.47 to estimate overall waste generation and landfilling for those years. To further extend waste generation estimates back to 1940, a regression equation relating waste generation to GNP and population was developed. Annual methane recovery data are from the U.S. Environmental Protection Agency's Landfill Methane Outreach Program database.[25]

Domestic and Commercial Wastewater Treatment

Emissions Sources

Emissions of methane from the treatment of wastewater occur when liquid waste streams containing high concentrations of organic materials are treated anaerobically (in the absence of oxygen). Treatment processes used in the United States are anaerobic digestion, aerobic, and facultative (combining aerobic and anaerobic processes) stabilization lagoons, septic tanks, and cesspools.[26] Treatment of wastewater solids using anaerobic digestion is the most obvious potential source of methane emissions; however, emission of significant quantities of methane from this process requires that the digester gas be vented rather than recovered or flared. Anaerobic and facultative lagoons involve retention of wastewater in impoundments, where the organic materials in the wastewater undergo bacterial decomposition. The growth of algae, which absorb carbon dioxide and release oxygen as a result of photosynthesis, sustains aerobic conditions at least near the surface of the lagoon. Bacteria deplete oxygen at the bottom of the lagoon, producing conditions suitable for methanogenic bacteria. The extent of the resulting anaerobic zone and the associated methane generation depend on such factors as organic loadings and lagoon depth. In facultative lagoons, unlike anaerobic lagoons, a significant aerobic zone persists.

Nearly 75 percent of U.S. households are served by sewers that deliver domestic wastewater to central treatment plants. Septic tanks or cesspools treat domestic wastewater from most of the remaining households.[27] Anaerobic digestion is

[25]See web site www.epa.gov/lmop.
[26]U.S. Environmental Protection Agency, Office of Policy, Planning and Evaluation, *International Anthropogenic Methane Emissions: Estimates for 1990*, EPA-230-R-93-010 (Washington, DC, January 1994), p. 10-9.
[27]U.S. Census, 1980, 1990, 2000.

frequently used to treat sludge solids at U.S. municipal wastewater treatment plants; however, anecdotal evidence suggests that neither recovery nor flaring of digester gas is common in the United States and that equipment for recovery and flaring of digester gas is poorly designed or maintained, allowing most of the methane produced to be released to the atmosphere.[28]

Estimation Methods

Insufficient information is available to develop separate estimates of methane emissions from each of the sources discussed above. Information on the type of treatment used by the thousands of municipal and industrial treatment facilities is not available. For instance, no reliable statistics were found for the use of anaerobic digestion at municipal treatment facilities. Knowledge regarding the emissions of methane from lagoons, septic systems, and cesspools is limited. Another difficulty is the overlap between municipal and industrial treatment systems. Many industrial concerns discharge wastewater, which may or may not have been treated, into municipal systems. Therefore, it is necessary to base the current estimate of methane emissions from wastewater treatment on the highly simplified approach recommended by the IPCC,[29] which assumes that each person in a developed nation contributes 0.05 kilogram of BOD_5 to domestic wastewater annually, and 15 percent of this wastewater is treated anaerobically, yielding 0.22 kilogram of methane per kilogram of BOD_5 in the wastewater.[30] It is assumed that recovery of methane at municipal wastewater treatment facilities is negligible.

Data Source

Estimates of the U.S. resident population on July 1 of each year were obtained from the U.S. Census Bureau.

Agricultural Sources

Enteric Fermentation in Domesticated Animals

Emission Sources

The breakdown of carbohydrates in the digestive track of herbivores (including insects and humans) results in the production of methane.[31] The volume of methane produced from this process (enteric fermentation) is largest in those animals that possess a rumen, or forestomach, such as cattle, sheep, and goats. The forestomach allows these animals to digest large quantities of cellulose found in coarse plant material. This digestion is accomplished by microorganisms in the rumen, some of which are methanogenic bacteria. These bacteria produce methane while removing hydrogen from the rumen. The majority (about 90 percent) of the methane produced by the methanogenic bacteria is released through normal animal respiration and eructation (belching). The remainder is released as flatus.

Estimation Method

The level of methane emissions from enteric fermentation in domesticated animals is a function of several variables, including quantity and quality of feed intake, the growth rate of the animal, its productivity (reproduction and/or lactation), and its mobility. To estimate emissions from enteric fermentation, the animals are divided into distinct, relatively homogeneous groups. For a representative animal in each group, feed intake, growth rate, activity levels, and productivity are estimated. An emissions factor per animal is developed based on these variables. The factor is then multiplied by population data for that animal group to calculate an overall emissions estimate. Because emissions from

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[28]William Hahn, Science Applications International Corporation, personal communication, May 23, 1996.

[29]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 6.23,www.ipcc.ch/pub/guide.htm

[30]Biological oxygen demand (BOD) represents the oxygen consumed by bacteria to decompose organic matter contained in a wastewater stream. It provides a measure of the organic loading of wastewater, which is the primary determinant of its potential to produce methane. BOD_5 is a standardized measurement of BOD that measures the oxygen consumed over a 5-day period.

[31]P.J. Crutzen, I. Aselmann, and W.S. Seiler, "Methane Production by Domestic Animals, Wild Ruminants, Other Herbivorous Fauna, and Humans," *Tellus*, Vol. 38B (1986), p. 272.

cattle represent about 95 percent of U.S. emissions from enteric fermentation, the estimation method for cattle is more complex and detailed.

Cattle. The U.S. cattle population is separated into dairy and beef cattle. Dairy cattle are then divided into replacement heifers 0-12 months old, replacement heifers 12-24 months old, and mature cows. Dairy cattle are further subdivided into regional populations in an effort to capture variations in diet and feed quality. Beef cattle are divided into six classes: replacements 0-12 months old, replacements 12-24 months old, mature cows, bulls, steers and heifers raised for slaughter under the weanling system, and steers and heifers raised for slaughter under the yearling system. These populations are then multiplied by emissions factors developed for each category of cattle based on their intake requirements.[32] Because characteristics critical in determining energy intake, and thus emissions rates, for cattle—such as growth rates and milk production— change annually, an effort to scale emission factors to these changes is made. For dairy cattle, emission factors are scaled to average milk production per cow on a regional basis. For beef cattle, emissions rates were pegged to average pre-slaughter live weights for the calves and adult cattle, respectively (Table A11).

Table A11. Average Pre-Slaughter Live Weights for U.S. Cattle and Calves, 1990 -2000
(Pounds)

Animal Class	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Cattle	1,136	1,163	1,169	1,161	1,189	1,183	1,169	1,173	1,203	1,210	1220
Calves	281	346	376	388	384	372	341	339	285	291	316

P = preliminary data.
Source: U.S. Department of Agriculture, web site www.usda.gov/nass/

Other Animals. For sheep, pigs, goats, and horses, populations are not desegregated below the species level. Emissions factors for each animal group are multiplied by their respective populations. Emission factors are drawn from the work of Crutzen et al.[33]

Data Sources

Population and slaughter weight data for cattle and population data for sheep and swine were obtained from the U.S. Department of Agriculture (USDA), National Agricultural Statistics Service, Livestock, Dairy, and Poultry Branch web site at www.nass.usda.gov:81/ipedb/. Population data for goats and horses are extrapolated from the USDA's *Census of Agriculture* for the years 1987, 1992 and 1997.[34] Emissions factors for dairy cattle scaled to milk production from U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 -1998*, EPA-236-R-00-001 (Washington, DC, April 2000) p. H-2.

Solid Waste of Domesticated Animals

Emission Sources

When the solid waste of animals is allowed to decompose under anaerobic conditions, methane is produced. The volume of methane produced varies according to the amount of organic material susceptible to decomposition within the waste (volatile solids) and the manner in which the waste is managed. Liquid-based waste management systems,

[32]U.S. Environmental Protection Agency, Office of Air and Radiation, *Anthropogenic Methane Emissions in the United States: Estimates for 1990* (Washington, DC, April 1993), p. 5-3; and U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-1997*, EPA-236-R-99-003 (Washington, DC, April 1999), p. G-2, web site www.epa.gov/globalwarming/publications/emissions/us2000.

[33]P.J. Crutzen, I. Aselmann, and W.S. Seiler, "Methane Production by Domestic Animals, Wild Ruminants, Other Herbivorous Fauna, and Humans," *Tellus*, Vol. 38B (1986), pp. 274-275.

[34]U.S. Department of Agriculture, National Agricultural Statistics Service, *Census of Agriculture, United States Summary and State Data*, Vol. 1, "Geographic Area Series," Part 51 (Washington, DC, 1987, 1992, and 1997).

in addition to providing a suitable anaerobic environment, provide the moisture necessary for methanogenic bacterial cell production and acid stabilization.[35] Thus, they result in the greater methane emissions.

Estimation Method

Methane emissions from the solid waste of domesticated animals are estimated by linking emissions to the volume of solid waste produced by a given animal, the volatile solids in that waste, and the manner in which the waste is handled. The volume of waste produced is controlled by the animal's size, diet, and energy requirements. As a proxy for these variables, typical animal mass as estimated in a 1990 inventory of livestock and poultry prepared by the U.S. Environmental Protection Agency[36] is used to determine emissions per animal. Animal sizes are adopted directly for all animals except cattle, for which masses are adjusted annually based on live pre-slaughter weights as reported by the U.S. Department of Agriculture. Volatile solids produced per kilogram of animal weight, maximum methane-producing capacity of each animal's waste and the share of waste handled in each management system are adopted from the work of Safley et al.[37] For all animals except dairy cattle, the share of waste handled in each management system is also drawn from Safley et al.

Methane conversion factors for dairy cattle are adopted on a State-by-State basis and are calculated from a weighted average of each State's manure management technique. Dairy cattle size and volatile solid production are drawn from the EPA. Resulting emissions factors are applied to State population data acquired from the U.S. Department of Agriculture, National Agricultural Statistics Service, Livestock, Dairy and Poultry Branch.

Data Sources

Population and slaughter weight data for cattle, and population data sheep, poultry, and swine were provided by the U.S. Department of Agriculture (USDA), National Agricultural Statistics Service (NASS), Livestock, Dairy, and Poultry Branch and were obtained via the Internet at www.usda.gov/nass/. Average broiler chicken populations for each year were estimated by multiplying the estimated number of broiler chickens hatched annually by 0.1425 based on their 7 week life cycle as recommended by the USDA's Economic Research Service.[38] Population data for goats and horses were extrapolated from USDA, NASS, *Census of Agriculture, United States Summary and State Data,* Vol. 1, "Geographic Area Studies," Part 51 (Washington, DC, 1987, 1992, 1997). Methane conversion factors weighted on a state-by-state basis are from U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 -1998*, EPA-236-R-00-001 (Washington, DC, April 2000) p. I-4.

Rice Cultivation

Emissions Sources

Methane is produced when organic material in flooded rice fields decomposes in the absence of oxygen (anaerobically). Between 60 and 90 percent of the methane generated is oxidized by bacteria in the soil, while an additional portion leaches into the groundwater. The majority of the methane that remains is transported through rice plants and is transpired into the atmosphere. A smaller amount of methane reaches the atmosphere by bubbling from the soil and by diffusing through the water column.

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[35]U.S. Environmental Protection Agency, Office of Air and Radiation, Anthropogenic Methane Emissions in he United States: Estimates for 1990 (Washington, DC, April 1993).

[36]U.S. Environmental Protection Agency, Office of Air and Radiation, *Anthropogenic Methane Emissions in he United States: Estimates for 1990* (Washington, DC, April 1993).

[37]L.M. Safley, M.E. Casada, J. Woodbury, and K. Roos, *Global Methane Emissions from Livestock and Poultry Manure* (Washington, DC: U.S. Environmental Protection Agency, February 1992), p. 18.

[38]Personal communication (May 1993).

Estimation Methods

A range of daily emissions rates has been developed from studies of rice fields in California,[39] Louisiana,[40] and Texas.[41] The high and low ends of the range, 0.1065 and 0.5639 grams of methane per square meter of land cultivated, are applied to the growing season length and the harvested area for each State that produces rice. In States with a second ("ratoon") crop, the additional area harvested is incorporated into the estimates.

Data Source

The area of rice harvested and the length of growing season data were obtained from the U.S. Department of Agriculture, National Agricultural Statistics Service, *Crop Production* (annual reports). Data on Florida rice harvests are from University of Florida, Institute of Food and Agricultural Sciences, Cooperative Extension Service,"Florida's 2000 Rice Variety Census," "An Overview of the Florida Rice Industry", web site, http://edis.ifas.ufl.edu.

Burning of Crop Residues

Emissions Sources

Between 40 and 50 percent of dry matter in crop residue is carbon.[42] When crop residues are burned for fodder, land supplementation, or fuel, incomplete combustion produces methane emissions.

Estimation Methods

This report assumes that 3 percent of all crop residues are burned, with the exception of rice, which is combusted at various levels over time. The share of rice crop residues in California estimated to be combusted declines from 75 percent in 1990 to 23 percent in 2000. The share of rice combusted throughout the remainder of the U.S. declines from 16 percent in 1990 to 9 percent in 2000.[43] To derive methane emissions, the dry weight and carbon content of each crop were determined and then multiplied by estimated combustion efficiencies (Table A12).

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[39]R. Sass, F. Fisher, S.Lewis, M. Jund, and F. Turner, "Methane Emissions From Rice Fields: Effect of Soil Properties," *Global Biogeochemical Cycles*, Vol. 8 (1994), p. 135.

[40]R.J. Cicerone, J.D. Shetter, and C.C. Delwiche, "Seasonal Variation of Methane Flux From a California Rice Paddy," *Journal of Geophysical Research*, Vol. 88 (1983), pp. 7203-7209.

[41]C.W. Lindau and P.K. Bolich, "Methane Emissions From Louisiana First and Ratoon Rice Crop," *Soil Science*, Vol. 156 (1993), pp. 42-48.

[42]A. Strehler and W. Stutzle, "Biomass Residues," in D.O Hall and R.P. Overend (eds.), *Biomass: Regenerable Energy* (Chichester, UK: John Wiley and Sons, 1987), p. 85.

[43] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 -1998*, EPA-236-R-00-001 (Washington, DC, April 2000) p.5-23.

Table A12. Factors Used in Estimating Methane and Nitrous Oxide Emissions from Crop Residue Burning

Crop Type	Residue/Crop Ratio	Dry Matter Content (Percent)	Carbon Content (Percent)	Nitrogen Content (Percent)
Barley	1.2	0.93	0.4485	0.0077
Beans	2.1	0.8535	0.45	0.023
Corn	1	0.91	0.4478	0.0058
Oats	1.3	0.901	0.42	0.0084
Peas	1.5	0.902	0.45	0.023
Peanut	1	0.86	0.45	0.0106
Potatoes	0.4	0.867	0.4226	0.011
Rice	1.4	0.91	0.3806	0.0072
Rye	1.6	0.9	0.4853	0.007
Sorghum	1.4	0.88	0.34	0.0085
Soybean	2.1	0.867	0.45	0.023
Sugarbeet	0.2	0.9	0.4072	0.0228
Sugarcane	0.8	0.62	0.4235	0.004
Wheat	1.3	0.93	0.4428	0.0062

Sources: A. Strehler and W. Stutzle, "Biomass Residues," in D. Hall and R. Overend (eds.), Biomass: Regenerable Energy (Chichester, UK: John Wiley and Sons, 1987), C. Li, S. Frolking and R. Harriss, "Modeling Carbon Biogeochemistry in Agricultural Soils," Global Biogeochemical Cycles, Vol. 8 (September 1994), E. Darley, "Emission Factors from Burning Agricultural Wastes Collected in California," Final Report, CAL/ARB Project 4-011 (Riverside, CA: University of California, 1977), U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999, EPA 236-R-01-001 (Washington, DC,April 2001), and G. Barnard, "Use of Agricultural Residues as Fuel," in J. Pasztor and L. Kristoferson (eds.), Bioenergy and the Environment (Boulder, CO: Westview Press, 1990)

Data Sources

Crop harvest sizes were obtained from U.S. Department of Agriculture, National Agricultural Statistics Service, *Crop Production* (Annual Reports).

Industrial Processes

Chemical Production

Emissions Sources

A wide variety of organic compounds (those containing carbon) are used as feedstocks in chemical production. High temperatures are often used to “crack” the molecular bonds of the compounds, with different temperatures producing specific chemicals. The process of cracking produces a number of chemical byproducts, including methane.

Estimation Methods

The IPCC has published emissions factors for methane emitted during the manufacture of ethylene, ethylene dichloride, styrene, methanol, and carbon black (Table A13). Production figures for the chemicals are multiplied by those emissions factors.

Data Source

Chemical production figures were obtained from the Chemical Manufacturers Association, *U.S. Chemical Industry Statistical Handbook* (Washington, DC, various years).

Table A13. Methane Emissions Factors for Industrial Processes
(Grams of Methane Emitted per Kilogram of Product Produced)

Industrial Product	Methane Emissions Factor
Coke	0.5
Sinter	0.5
Pig Iron	0.9
Carbon Black	11.0
Ethylene	1.0
Dichloroethylene	0.4
Styrene	4.0
Methanol	2.0

Source: Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 2.6, web site www.ipcc.ch/pub/guide.htm.

Iron and Steel Production

Emissions Sources

Coke, sinter, and pig iron are the principal material inputs for the production of iron and steel. Coke is produced by heating coal in the absence of oxygen. One of the gaseous byproducts of this process is methane. During the next step in the production process, coke, iron ore, and flux materials are combined to form sinter. The coke is burned to create heat, causing the sinter to agglomerate. During agglomeration, methane is released. Coke and iron are then added to flux materials in a blast furnace and reduced to iron, slag, and exhaust gases. Methane is one of the exhaust gases.

Estimation Methods

The IPCC has published emissions factors for methane emitted during the production of coke, sinter, and pig iron.[44] Production figures for iron and steel inputs are multiplied by those emissions factors.

Data Source

Coke, sinter, and pig iron production data are published annually by the American Iron and Steel Institute in its *Annual Statistical Report* (Washington, DC, various years).

Nitrous Oxide

Most anthropogenic nitrous oxide emissions in the United States can be attributed to agricultural and energy sources. In particular, 51 percent of estimated emissions of nitrous oxide were attributable to nitrogen fertilization of agricultural soils. Motor vehicle fuel combustion accounts for another 18 percent of 2000 emissions. It should be noted that the range of uncertainty associated with emissions from mobile combustion and fertilizer use is quite large. Emissions estimates in this report include: mobile source combustion from passenger cars, buses, motorcycles, trucks, and other mobile sources; stationary source combustion from the commercial, residential, industrial, and electrical utility sectors; fertilizer application; burning of crop residues; livestock manure management; human sewage; waste combustion; and industrial production of adipic acid and nitric acid.

[44]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 2.23,www.ipcc.ch/pub/guide.htm

Energy Use

Mobile Combustion

Emissions Sources

Nitrous oxide emissions are produced as a byproduct of fuel combustion. During combustion, nitrous oxide (N_2O) is produced as a result of chemical interactions between nitrogen oxides (NO, NO_2 and NO_3) and other combustion products. Since nitrous oxide decomposes at high temperatures, most stationary combustion systems (such as electric power generation) emit little nitrous oxide. However, under some conditions, the catalytic converters fitted as pollution control devices on most U.S. vehicles will convert nitrogen oxides into nitrous oxide. The relevant conditions appear to be when the catalytic converter is just warming up, but before it reaches normal operating temperature, if the catalytic converter is not working properly, or if the catalyst is affected by excessive levels of sulfur in the gasoline.

Estimation Methods

In general, EIA estimates nitrous oxide emissions from highway vehicles by multiplying emissions factors (grams of nitrous oxide per mile driven) by national-level vehicle miles traveled. Research indicates that emissions rates differ among motor vehicles by vehicle type, and by type of catalytic converter (associated with the vintage of the motor vehicle) for light duty vehicles. Consequently, EIA partitions national-level vehicle miles traveled by vehicle type (i.e. by passenger cars, light-duty trucks, buses, motorcycles, and heavy-duty trucks), as well as by motor vehicle vintage (model year) for cars and light duty trucks.

For non-highway sources, an emissions factor in grams of nitrous oxide per unit of fuel consumed is applied to fuel consumption data. Since off-road vehicles rarely have catalytic converters (and vintage data is scarce) no attempt is made to track vehicle vintages for the non-highway sources.

Data Sources

Emissions factors for motor vehicle nitrous oxide have been the subject of considerable discussion and research. The IPCC's *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (Paris, France, 1997)included revised nitrous oxide emissions factors for motor vehicles that were four times higher those used in the previous reference manual. The EPA's Office of Mobile Sources, stimulated by the IPCC report, undertook an automotive testing program in the summer of 1998. The Office of Mobile Sources results were published in U.S. Environmental Protection Agency, *Emissions of Nitrous Oxide from Highway Mobile Sources*, EPA-420-R-98-009 (Washington, DC, August 1998), and have been used in this report. These emissions factors are considerably lower than the emissions factors in the IPCC report but somewhat higher than emissions factors used in EIA's *Emissions of Greenhouse Gases in the United States* reports for 1996 and before, and higher than the emissions factors suggested by the IPCC for use with European vehicles.

EIA collected data on miles traveled in personal transportation vehicles (cars and light-duty trucks) as part of its triennial Residential Transportation Energy Consumption Survey (RTECS): Energy Information Administration, *Household Vehicles Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, July 1996, and previous years). This survey contains data for the years 1983, 1985, 1988, 1991, and 1994. Vehicle miles traveled for other years are estimated using weighted averages from survey data in conjunction with statistics on the U.S. fleet of cars and trucks by model year, provided by the American Automobile Manufacturers Association*, AAMA Vehicle Facts and Figures* (Detroit, MI, various years) and by Ward's Communications Inc., *Ward's Automotive Yearbook* (Southfield, MI, 2000). Vehicle miles traveled for non-household vehicles, motorcycles, buses, and heavy-duty trucks were obtained from the U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics* (Washington, DC, various years), web site www.fhwa.dot.gov/ohim/ohimstat.htm.

Fuel consumption for ships, locomotives, farm and construction equipment is based on data from the Energy Information Administration, *Fuel Oil and Kerosene Sales*, DOE/EIA-0535 (Washington, DC, various years). Jet and piston-powered aircraft fuel consumption data are contained in the Energy Information Administration's *Petroleum Supply Annual*,

DOE/EIA-0340 (Washington, DC, various years). Data on fuel consumption by recreational boats are taken from Oak Ridge National Laboratory: Center for Transportation Analysis, *Transportation Energy Data Book* (Oak Ridge, TN, various years), web site www-cta.ornl.gov/publications/tedb.html.

Stationary Combustion

Emissions Sources

As with mobile sources, nitrous oxide emissions are produced as a byproduct of fuel combustion. The three fuels of primary importance burned by stationary sources are coal, fuel oil, and natural gas. Combustion systems powered by coal produce the most nitrous oxide, approximately 62 percent of annual emissions. Since 1990, electric utilities as a sector, have consistently accounted for more than one-half of total nitrous oxide emissions from stationary combustion. Other important sources are commercial facilities, industrial facilities, and residences.

Estimation Methods

Nitrous oxide emissions from stationary combustion are estimated by multiplying fuel consumption figures for each fuel type and stationary source by emissions factors for each type of fuel. Nitrous oxide emissions from stationary combustion include emissions from the consumption of wood in the residential, commercial, industrial, and electric utility sectors. Emissions are estimated by applying emissions factors for coal, oil, natural gas, and wood, to EIA's consumption data for each fuel in the commercial, residential, industrial, and electric utility sectors.

Data Sources

Emissions coefficients for stationary fuel were obtained from Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997),www.ipcc.ch/pub/guide.htm. Fuel consumption data were drawn from the Energy Information Administration, *State Energy Data Report 1997*, DOE/EIA-0214(99) (Washington, DC, September 1999) for 1980-1997; and *Monthly Energy Review*, DOE/EIA-0035(01/07) (Washington, DC, July 2001) for 1998-2000. Residential woodfuel consumption data were derived from EIA's *Annual Energy Review 2000*, DOE/EIA-0384(00) (Washington, DC, July 2001).

Agriculture

Nitrogen Fertilization of Agricultural Soils

Emissions Sources

Nitrous oxide is a waste product of certain classes of bacteria normally present in soil. When nitrogen (in the form of natural or artificial fertilizers) is added to natural or agricultural soils, the action of these bacteria is stimulated. However, the extent to which adding nitrogen stimulates nitrous oxide emissions is highly uncertain. The bacteria that emit nitrous oxide have natural competitors, which may be more or less successful in particular settings. In addition, conditions may be more or less propitious for bacterial action: the soil may be too moist or too dry, too compacted, too acid or alkaline, too warm or too cold. The form in which nitrogen is applied may be subject to faster or slower release to the waiting bacteria. Further, excess nitrogen will escape from the location of application through runoff and will be subject to decomposition in diverse natural environments. Thus, measured emissions from even large numbers of specific sites are exceptionally difficult to generalize into an estimate of national emissions.

Estimation Methods

Following the IPCC *Reference Manual*, this report estimates nitrogen applications to soils from the following sources:

- Use of nitrogen fertilizers (computed directly from fertilizer data)

- Nitrogen in animal manure applied to agricultural soils (estimated from animal populations)
- Nitrogen in crop residues applied to agricultural soils (estimated from crop production statistics)
- Biological fixation of nitrogen in agricultural soils (estimated from crop production statistics)

For estimating nitrous oxide emissions from the first three sources, following the IPCC guidelines EIA assumes that 1.25 percent of the nitrogen applied is emitted to the atmosphere as nitrous oxide and 30 percent escapes into the environment. Some 2.5 percent of the nitrogen that escapes is ultimately converted into nitrous oxide in the form of emissions from streams and bodies of water. A further 10 percent of the nitrogen applied to soils is assumed to be released as gas in the form of nitrogen oxides and ammonia, and 1 percent of that nitrogen is assumed to be ultimately converted into nitrous oxide.[45]

To estimate nitrous oxide emissions from the biological fixation of nitrogen in crops, annual production statistics for nitrogen-fixing crops (alfalfa, beans, lentils, peanuts, and soybeans) were obtained from the U.S. Department of Agriculture's *Crop Production* annual reports. Crop product values for these crops were then converted to total crop (crop product plus crop residue) dry biomass in mass units of dry matter, by applying residue-to-crop ratios and dry matter fractions. The total crop values in dry biomass units were then used to calculate the crop nitrogen content that is released in the form of nitrous oxide. Finally, nitrous oxide emissions factors were then applied to calculate nitrous oxide emissions from the biological fixation of nitrogen in crops.[46]

Data Sources

Estimates of total U.S. fertilizer consumption were obtained from reports by the Tennessee Valley Authority Fertilizer Research Center for various years through 1994: J.T. Berry et al., *Commercial Fertilizers* (Muscle Shoals, AL: Tennessee Valley Authority, Fertilizer Research Center, Reports for 1986-1991 and 1993-1994) and The Fertilizer Institute for 1995 through 2000. Estimates of nitrous oxide from the biological fixation of nitrogen in crops, were based on crop production statistics obtained from the U.S. Department of Agriculture's *Crop Production* annual reports. For nitrogen in animal manure, see the section on "Solid Waste of Domesticated Animals." For nitrogen in crop residues, see the section on "Crop Residue Burning" under methane or nitrous oxide.

Crop Residue Burning

Emissions Sources

Crop residues are commonly disposed of by incorporation into the soil, spreading over the soil surface to prevent erosion, as animal bedding, or through burning. Burning crop residues releases nitrous oxide into the atmosphere. The burning of crop residues occurs throughout the United States, although it is illegal in certain areas. There are no accurate estimates of the amount of crop residue burned in the United States.

Estimation Methods

This report assumes that 3 percent of all crop residues are burned, with the exception of rice, which is combusted at various levels over time.The share of rice crop residues in California estimated to be combusted declines from 75 percent in 1990 to 23 percent in 2000. The share of rice combusted throughout the remainder of the U.S. declines from 16 percent in 1990 to 9 percent in 2000.[47] The amount of crop residue burned is discounted by an assumed combustion

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[45]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 1.53,www.ipcc.ch/pub/guide.htm

[46]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), pp. 4.85-4.94,www.ipcc.ch/pub/guide.htm

[47] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 -1999*, EPA-236-R-01-001 (Washington, DC, April 2001) p.5-23.

efficiency, multiplied by its dry matter content and nitrogen content, and then converted to nitrous oxide using a standard ratio of nitrous oxide to nitrogen content.

Data Sources

Crop harvest sizes were obtained from U.S. Department of Agriculture, National Agricultural Statistics Service, *Crop Production* (Annual Reports).

Solid Waste of Domesticated Animals

Emissions Sources

Nitrous oxide is emitted as part of the denitrification of animal manure. The volume of nitrous oxide emissions is a function of the amount of manure produced, the nitrogen content of the manure, and the method for handling the animal waste. Waste managed by a solid storage or pasture range method may emit 20 times the nitrous oxide per unit of nitrogen content that is emitted from anaerobic lagoon or other liquid systems.

Estimation Methods

Nitrous oxide emissions from the solid waste of domesticated animals are estimated by linking emissions to the volume of solid waste produced by a given animal, the volatile solids in that waste, the nitrogen content of the waste, and the manner in which the waste is managed. Animal populations are divided into distinct, relatively homogeneous groups. The U.S. cattle population is separated into dairy and beef cattle. Emissions of nitrous oxide from poultry, sheep, pigs, goats, and horses are also estimated. For each group of animals, a per-head volatile solids production and an associated nitrogen content within the volatile solids are assigned. These values are multiplied by animal populations to derive total nitrogen excreted. For each animal group, excretions are distributed among the manure management systems used. The ratio of nitrous oxide production to nitrogen content for each management technique is applied to provide an emissions estimate for each animal group, broken down by manure management system. The emissions are then summed to calculate an overall emissions estimate.

Data Sources

Population and slaughter weight data for cattle and population data for sheep, poultry, and swine were obtained from the U.S. Department of Agriculture (USDA), National Agricultural Statistics Service, Livestock, Dairy, and Poultry Branch, web site www.usda.gov/nass/. Average broiler chicken populations for each year were estimated by multiplying the estimated number of broiler chickens slaughtered annually by 0.1425, based on their 7-week life cycle as recommended by the USDA's Economic Research Service.[48] Population data for goats and horses were extrapolated from U.S. Department of Commerce, Economics and Statistics Administration, Bureau of the Census, *Census of Agriculture, United States Summary and State Data*, (Washington, DC, 1982, 1987, 1992, and 1997). Volatile solids content, nitrogen content of wastes by species, manure management systems, and nitrogen to nitrous oxide conversion rates were taken from Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), pp. 4.88-4.93, www.ipcc.ch/pub/guide.htm

[48]Personal communication, May 1993.

Waste Management

Waste Combustion

Emissions Sources

Like other stationary and mobile combustion processes, the burning of garbage and nonhazardous solid waste produces nitrous oxide emissions. There are 160 municipal waste combustion plants in the United States, with 114 plants generating energy. Emission levels are dependent on the composition of waste burned and combustion temperatures.[49] Very high temperatures reduce nitrous oxide emissions.

Estimation Methods

The total annual volume of municipal solid waste generated in the United States was multiplied by the share of waste incinerated. Total waste incinerated was then multiplied by a factor of 30 grams of nitrous oxide per metric ton of waste incinerated to calculate total nitrous oxide emissions from this source.

Data Sources

Waste generation data and share incinerated were drawn from *Biocycle* magazine, "The State of Garbage in America" (various years). Waste generation data for 2000 were based on 1999 data scaled to GDP growth of 4.1percent with the share of waste combusted held steady. The emissions factor was taken from U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-1998*, EPA-236-R-00-0010 (Washington, DC, April 2000), web site www.epa.gov/publications/emissions/index.html.

Human Sewage in Wastewater

Emissions Sources

When human sewage is treated in wastewater systems, the nitrogen-based organic matter in the waste generates nitrous oxide through nitrification and denitrification. Under aerobic conditions, ammonia is converted to nitrate. As oxygen dissipates and an anaerobic environment governs, nitrate is converted to nitrous oxide.

Estimation Methods

Nitrous oxide emissions are estimated as a function of national population, per capita protein consumption, and the fraction of nitrogen in protein. The fraction of nitrogen in protein is assumed to be 16 percent, and 1 kilogram of nitrous oxide is assumed to be emitted per 100 kilograms of nitrogen in wastewater.

Data Sources

U.S. population data are from the Bureau of Census. Per-capita protein intake is from the Food and Agriculture Organization, *FAOSTAT Statistical Database*. Nitrogen content and nitrous oxide conversion factor are from U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-1998*, EPA-236-R-00-0010 (Washington, DC, April 2000), web site www.epa.gov/publications/emissions/index.html.

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[49]U.S. Environmental Protection Agency, Office of Policy, Planning and Evaluation, *U.S. Greenhouse Gas Emissions and Sinks 1990-1999*, EPA-236-R-01-001 (Washington, DC, April 2001), p. 7-5.

Industrial Processes

Adipic Acid Production

Emissions Sources

Manufacture of adipic acid is one of the two principal sources of nitrous oxide from industrial processes. Adipic acid is used primarily in the manufacture of nylon fibers and plastics in carpet yarn, clothing, and tire cord. Other uses of adipic acid include production of plasticizers for polyvinyl chloride and polyurethane resins, lubricants, insecticides, and dyes. In the United States, three companies, which operate a total of four plants, manufacture adipic acid by oxidizing a ketone-alcohol mixture with nitric acid. Creation of nitrous oxide is an intrinsic byproduct of this chemical reaction.

Estimation Methods

Emissions of nitrous oxide from production of adipic acid are calculated by multiplying adipic acid production figures by nitrous oxide emissions coefficients. For every metric ton of adipic acid produced, 0.3 metric ton of nitrous oxide is created.[50] Currently, three plants control emissions by thermally decomposing the nitrous oxide, and 98 percent of the potential emissions from the production of adipic acid, subject to abatement controls, are eliminated by this technique.[51] In 1999, 97.4 percent of total estimated U.S. production of adipic acid was subject to abatement control measures.

Data Sources

Adipic acid production figures were obtained from *Chemical and Engineering News*, annual report on the "Top 50 Industrial Chemicals" (April issue, various years). For 1996 through 1999, U.S. total adipic acid production was obtained from the American Chemical Council (formerly the Chemical Manufacturers Association). The adipic acid emissions coefficient was taken from M. Thiemens and W. Trogler, "Nylon Production: An Unknown Source of Atmospheric Nitrous Oxide," *Science*, Vol. 251, No. 4996 (February 22, 1991), p. 932.

Nitric Acid Production

Emissions Sources

Nitric acid is a primary ingredient in fertilizers. The process for manufacturing this acid involves oxidizing ammonia (NH_3) with a platinum catalyst. Nitrous oxide emissions are a direct result of the oxidation.

Estimation Methods

The IPCC guidelines indicate emissions factors of 2 to 9 grams of nitrous oxide per kilogram of nitric acid manufactured.[52] The emissions estimates presented in this report are calculated by multiplying the annual quantity of nitric acid produced by the midpoint (5.5 grams nitrous oxide per kilogram of product) of the emissions range. There is, however, a considerable degree of uncertainty associated with this estimate.

Data Sources

Nitric acid production figures were based on data published by the U.S. Department of Commerce, Bureau of the Census, in its annual and quarterly *Current Industrial Reports* on fertilizer materials. The nitric acid emissions coefficient was taken from Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised*

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[50]M.H. Thiemens and W.C. Trogler, "Nylon Production: An Unknown Source of Atmospheric Nitrous Oxide," *Science*, Vol. 251, No. 4996 (February 22, 1991), p. 932.

[51]Radian Corporation, *Nitrous Oxide Emissions From Adipic Acid Manufacturing* (Rochester, NY, January 1992), p. 10.

[52]Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), p. 2.18,www.ipcc.ch/pub/guide.htm

1996 IPCC Guidelines for National Greenhouse Gas Inventories, Vol. 3 (Paris, France, 1997), www.ipcc.ch/pub/guide.htm

HFCs, PFCs, and Sulfur Hexafluoride

Emissions Sources

HFCs, PFCs, and sulfur hexafluoride have hundreds of uses, but the bulk of emissions come from a few broad categories of use:

- As refrigerants or working fluids in air conditioning and refrigeration equipment
- As solvents in various industrial processes
- As blowing agents for making insulating foams
- As fugitive emissions from various industrial processes, including the manufacture of halocarbons.

The emissions profile differs for each emissions source. Refrigerants are used in a closed cycle inside cooling equipment, and they tend to leak out when the equipment is scrapped or serviced. Some portion of the refrigerants is captured and recycled or destroyed, rather than emitted, when equipment is serviced. HFCs solvent applications are often recycled, but net consumption (after recycling) is probably a good indicator of emissions. HFCs used as blowing agents can be characterized by the type of foam manufactured: HFCs s used to make “open cell” foam are released to the atmosphere immediately, while HFCs used to make “closed cell” foam are trapped within the foam for the life of the foam, which can vary (depending on the use) from a few weeks to many years.

Estimation Methods

For the years 1990 through 1999, EIA has relied primarily on estimates of HFC, PFC, and sulfur hexafluoride emissions presented in the U.S. Environmental Protection Agency’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-1999*, EPA-236-R-00-001 (Washington, DC, April 2001). The preliminary 2000 emissions estimates for sulfur hexafluoride, PFCs, and most HFCs are advance estimates developed by the EPA and provided to the EIA, courtesy of the EPA’s Climate Protection Division. The preliminary 1999 emissions estimates for HFC-152, HFC-227ea, and HFC-4310mee were derived by extrapolating the trends shown in the 1996 through 1998 estimates.

Data Sources

EPA estimates of emissions of HFCs, PFCs, and sulfur hexafluoride are from the U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-1999*, EPA-236-R-00-001 (Washington, DC, April 2001), web site www.epa.gov/globalwarming/publications/emissions/us2000/index.html.