Electric Power Annual 2008

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Updated June 2010, including corrected data on capacity resources and capacity margins by NERC region

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Preface

The Electric Power Annual 2008 summarizes electric power industry statistics at the national level. The publication provides industry decision-makers, government policymakers, analysts, and the general public with historical data that may be used in understanding U.S. electricity markets. The *Electric Power Annual* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; U.S. Energy Information Administration (EIA); U.S. Department of Energy.

Data in this report can be used in analytic studies for public policy and business decisions. The chapters present information and data in the following areas: electricity generation; electric generating capacity; demand, capacity resources, and capacity margins; fuel, consumption and receipts; emissions; electricity trade; retail electric customers, sales, revenue and average retail price; electric utility revenue and expense statistics; and demand-side management.

Monetary values in this publication are expressed in nominal terms.

Data published in the *Electric Power Annual* are compiled from four surveys completed annually or monthly by electric utilities and other electric power producers and submitted to the EIA and five surveys administered by other government organizations[1]. The EIA forms are described in detail in the "Technical Notes."

An important note to the reader: In this edition of the Electric Power Annual, changes have been made to the order of chapters, to improve the flow of the publication. Furthermore, a new Chapter 5 has been added to display selected characteristics of the electric power industry. For the convenience of the reader, a crosswalk list between the chapters, tables and illustrations of the 2007 and 2008 Electric Power Annual publications is provided in the Preface.

[1] The Department of Energy, Office of Electricity Delivery and Energy Reliability; the Federal Energy Regulatory Commission; the Department of Agriculture, Rural Utility Service; and the National Energy Board of Canada.

The Crosswalk Between Chapters, Tables and Illustrations of the Electric Power Annual 2008 and 2007

Chapter Crosswalk

Table of Contents for 2008	Table of Contents for 2007
Year-in-Review	Year-in-Review
Chapter 1. Capacity	Chapter 2. Capacity
Chapter 2. Generation and Useful Thermal Output	Chapter 1. Generation and Useful Thermal Output
Chapter 3. Fuel and Emissions	Chapter 4. Fuel, and Chapter 5. Emissions
Chapter 4. Demand, Capacity Resources, and Capacity Margins	Chapter 3. Demand, Capacity Resources, and Capacity Margins
Chapter 5. Characteristics of the Electric Power Industry	New Chapter in EPA 2008, no 2007 reference
Chapter 6. Trade	Chapter 6. Trade
Chapter 7. Retail Customers, Sales, and Revenue	Chapter 7. Retail Customers, Sales, and Revenue
Chapter 8. Revenue and Expense Statistics	Chapter 8. Revenue and Expense Statistics
Chapter 9. Demand-Side Management	Chapter 9. Demand-Side Management
Appendices	Appendices
A. Technical Notes	A. Technical Notes

Table Crosswalk

Chapter 1 Tables:

2008	2007
Table 1.1.	Table 2.1.
Table 1.1.A.	Table 2.1.A.
Table 1.2.	Table 2.2.
Table 1.3.	Table 2.3.
Table 1.4. (Name modified in 2008)	Table 2.4.
--	Table 2.5. is dropped in 2008.
Table 1.5.	Table 2.6.
Table 1.6.A.	Table 2.7.A.
Table 1.6.B.	Table 2.7.B.
Table 1.6.C.	Table 2.7.C.
Table 1.7.	Table 2.8.
Table 1.8.	Table 2.9.
Table 1.9.	Table 2.10.
Table 1.10.	Table 2.11.
Table 1.11.	Table 2.12.
Table 1.12.	Table 2.13.

Chapter 2 Tables:

All table orders remain the same, with chapter references changing from Table 1. in 2007 to Table 2. in 2008.

For example, Table 1.1. in 2007 has become Table 2.1 in 2008.

Chapter 3 Tables:

2008	2007
Table 3.1.	Table 4.1.
Table 3.2.	Table 4.2.
Table 3.3.	Table 4.3.
Table 3.4.	Table 4.4.
Table 3.5.	Table 4.5.
Table 3.6.	Table 4.6.
Table 3.7.	Table 4.7.
Table 3.8.	Table 4.8.
Table 3.9.	Table 5.1.
Table 3.10.	Table 5.2.
Table 3.11.	Table 5.3.

Chapter 4 Tables:

All table orders remain the same, with chapter references changing from Table 3. in 2007 to Table 4. in 2008.
For example, Table 3.1. in 2007 has become Table 4.1 in 2008.

Chapter 5 Tables:

2008	2007
Table 5.1. (New table in 2008)	--
Table 5.2.	Table A6. of the appendix
Table 5.3. (New table in 2008)	--
Table 5.4.	Table A7. of the appendix
Table 5.5. (New table in 2008)	--

Chapter 6, 7, 8, 9 Tables:

No change to tables, there is one-to-one correspondence between the two years.

Appendix A.

2008	2007
Table A1.	Table A1.
Table A2.	Table A2.
Table A3.	Table A3.
Table A4.	Table A4.
Table A5.	Table A5.
Table 5.2.	Table A6.
Table 5.4.	Table A7.

Illustrations Crosswalk

2008	2007
Figure ES1.	Figure ES1.
Figure ES2.	Figure ES2.
Figure ES3.	Figure ES3.
Figure ES4.	Figure ES4.
Figure 1.1.	Figure 2.1.
Figure 2.1	Figure 1.1
Figure 4.1.	Figure 3.1
Figure 4.2	Figure 3.2

Figure 7.1 through Figure 7.7 numbering remain the same in 2007 and 2008.

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Electric Power Industry 2008: Year in Review

Overview

In 2008, electricity generation and sales were adversely affected by the weakening economy. Annual net electric power generation decreased for the first time since 2001, dropping 0.9 percent from 4,157 million megawatthours (MWh) in 2007 to 4,119 million MWh in 2008. Summer peak load (noncoincident) fell by 3.8 percent, from 782,227 megawatts (MW) in 2007 to 752,470 MW in 2008. Winter peak load (noncoincident), which is always smaller than summer peak load, increased in 2008 by 0.9 percent, from 637,905 MW in 2007 to 643,557 MW in 2008. Nationally, the contiguous U.S. experienced an average temperature that was the coolest in more than ten years.[1]

Fossil fuel prices showed significant volatility during 2008. Natural gas spot prices as delivered to electric plants were $8.27 per MMBtu in January, rose to $12.14 per MMBtu in June, and fell to $6.36 per MMBtu in November. The overall 27.2-percent increase in average fossil fuel costs delivered to electric plants from 2007 contributed to the 6.7-percent increase in average retail electricity prices, from 9.1 to 9.7 cents per kilowatthour (kWh). Between 2004 and 2008, the average price of fossil fuels delivered to electric plants increased a cumulative 65.7 percent. Over the same time period, the national average retail price of electricity increased 28.0 percent, from 7.6 cents per kWh in 2004 to 9.7 cents per kWh in 2008.

While electricity generation from the primary fuel sources decreased in 2008 (coal by 1.5 percent, natural gas by 1.5 percent, and nuclear by 0.03 percent), generation from all renewable sources increased, with the exception of wood and wood derived fuels. Most notably, wind generation increased 60.7 percent, from 34.5 million MWh in 2007 to 55.4 million MWh in 2008. For the first time, wind generation constituted a larger share of total electric generation than either petroleum or wood and wood-derived fuels. At the time of this writing, 24 States have put in place Renewable Portfolio Standards and five additional States have nonbinding goals for renewable energy[2]. Several pieces of recently enacted Federal legislation have also offered substantial financial incentives for renewable electricity production.

In 2008, total net summer generating capacity increased 15,283 MW, a gain of 1.5 percent over 2007. New wind capacity accounted for 53.2 percent of that increase, with 8,136 MW installed during 2008. Wind net summer capacity increased 49.3 percent from 2007 to 2008. New natural gas-fired capacity of 4,556 MW accounted for 29.8 percent of the total net capacity increase. Natural-gas fired capacity additions have been declining since a peak in 2002.

The capacity factor for combined cycle natural gas units increased from 33.5 percent in 2003 to 42.0 percent in 2007, and then fell slightly to 40.7 percent in 2008. The overall improvement in the average capacity factor since 2003 reflects both the increased reliance on combined cycle generation to meet energy requirements and further efficiency gains in combined cycle generation technology. Nuclear and coal-fired generation had the highest average capacity factors at 91.1 percent and 72.2 percent, respectively, in 2008.

Estimated U.S. electric power plant carbon dioxide emissions fell 2.5 percent from 2007 to 2008, from 2,540 million metric tons to 2,477 million metric tons, largely due to decreased fuel consumption. Sulfur dioxide (SO_2) emissions fell 13.4 percent, from 9.0 to 7.8 million metric tons, between 2007 and 2008. This amounts to the largest year-over-year decline since 1995. The large reductions in SO_2 in 2008 result in part from a decline in fuel consumption but mostly from the installation of emissions reduction equipment in response to the Environmental Protection Agency's Clean Air Interstate Rule (see Emissions section). 2008 data also show significant reductions to emissions of nitrogen oxides (NO_x), which dropped 8.8 percent, -from 3.7 to 3.3 million metric tons. Since 1997, sulfur dioxide and nitrogen oxide emissions declined by 41.9 percent and 48.8 percent, respectively.

Generation

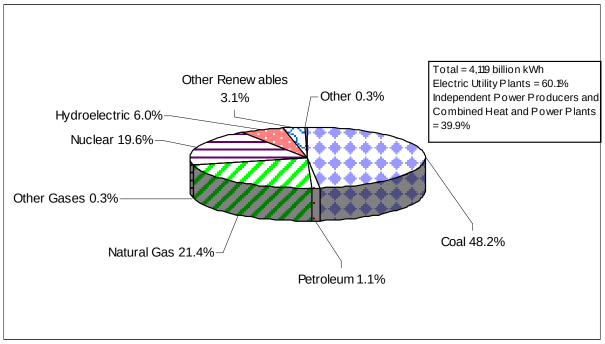
Net generation of electric power fell 0.9 percent in 2008, to 4,119 million megawatthours (MWh) from 4,157 million MWh in 2007 (Figure ES1). According to the Bureau of Economic Analysis, the real U.S. gross domestic product increased 0.4 percent in 2008.[3] The Federal Reserve Board, however, reported a 2.2 percent decrease in total industrial production.[4] The National Oceanic and Atmospheric Administration (NOAA) reported that 2008 was the "coolest year in more than ten years." Heating degree days in 2008 were 5.6 percent higher, while cooling degree days were 8.7 percent lower than they were in 2007. NOAA's Residential Demand Temperature Index[5] was 33.0 percent higher in 2008 than it was in 2007. The combination of weak economic activity and reduced summer electricity demand for cooling appears to have

[1] http://www.ncdc.noaa.gov/oa/climate/research/2008/ann/us-summary.html
[2] Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy

[3] See www.bea.gov
[4] See Federal Reserve statistical release, G.17 (419) 2009 Annual Revision, Industrial Production and Capacity Utilization: The 2009 Annual Revision, March 27, 2009.
[5] http://www.ncdc.noaa.gov/oa/climate/research/cie/redti.php

contributed to the 0.9 percent decrease in net generation, as compared with the 2.3 percent increase observed in 2007.

Figure ES1. U.S. Electric Power Industry Net Generation, 2008



Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

The three primary energy sources for generating electric power in the United States, coal, natural gas, and nuclear energy, consistently provided between 85.0 and 89.5 percent of total net generation during the period 1997 through 2008 (Table 2.1). Petroleum's relative share of total net generation was down to 1.1 percent in 2008. Although conventional hydroelectric power's share of generation was up slightly in 2008, the general trend of this share is one of decline. In 2008, generation from conventional hydroelectric plants accounted for 6.2 percent of total net generation, as compared to 10.2 percent in 1997. Excluding conventional hydroelectric, renewable energy sources contributed 3.1 percent of total net electric generation in 2008, up from 2.5 percent in 2007. This marks the fifth consecutive year in which this category's share of total net generation has increased, and the first time it crossed the three percent threshold. The largest portion of this increase comes from wind generation, which increased from 0.8 percent to 1.3 percent of total net electric generation.

In 2008, electricity generation from coal-fired capacity fell 1.5 percent. Coal-fired generation decreased from 2,016 million MWh in 2007 to 1,986 million MWh in 2008, the lowest coal-fired generation total since 2004. Declines in Pennsylvania, Georgia, North Carolina, and Virginia accounted for 57.8 percent of the national decline. Issues involving individual plants played a key role in the regional decline. In Pennsylvania, 45.4 percent of the drop in coal-fired generation can be attributed to the Homer City plant. Generation at Homer City was down 17.1 percent from its total in 2007, due in part to maintenance outages and economic dispatch. In North Carolina, the Marshall plant's coal-fired generation level was 13.9 percent lower than it was in 2007. This drop accounted for almost half – 49.4 percent – of the decrease in North Carolina's coal-fired electricity production.

Coal's share of total net generation continued its downward trend, accounting for 48.2 percent in 2008 as compared to 48.5 percent in 2007 and 52.8 percent in 1997. Nevertheless, providing 1,986 million MWh, it remains the primary source of baseload generation in the United States.

Following a decade of solid growth, natural gas has increased its share of the electricity market from 13.7 percent in 1997 to 21.4 percent in 2008. Net generation from natural gas-fired capacity fell 1.5 percent, from 897 million MWh in 2007 to 883 million MWh in 2008, the first drop in natural gas-fired generation since 2003. Natural gas-fired generation accounted for 21.4 percent of total net generation in 2008, down from 21.6 percent in 2007. Despite the decrease, natural-gas fired generation was the second leading contributor to total net generation for the third consecutive year, surpassing nuclear generation, which had a 19.6 percent share of total net generation.

Net generation at nuclear plants was down fractionally in 2008 to 806.2 million MWh from 806.4 million MWh. Between 1997 and 2008, the nuclear share of total net generation ranged from a low of 18.0 percent to a high of 20.6 percent, with an annual average growth of 2.3 percent, despite the fact that no new nuclear units have been constructed. Since 1997, average capacity factors for nuclear plants increased from 72.0 percent to 91.8 percent in 2007 (Table 5.3). In 2008, however, the capacity factor for nuclear plants was down slightly to 91.1 percent. In past years, growth in nuclear generation was the result of both improved capacity factors and uprates of existing plants. The net summer capacity of nuclear plants increased due to uprates in 2008 by 489 MW, continuing the overall upward trend. From 1998 through 2008, net summer capacity of existing nuclear plants increased by 3,685 MW.

Net generation from renewable energy sources, excluding conventional hydroelectric generation, increased 19.9 percent in 2008, following an increase of 9.0 percent in 2007 (Table 2.1a). A large part of this growth was due to increased wind generation, which totaled 55.4 million MWh, or 1.3 percent of total net generation. For the first time, wind generation constituted a larger share than biomass, and also a larger share than petroleum. The top 5 wind-generating States were Texas, California, Minnesota, Iowa, and Washington. Texas, where wind generation was up 80.2 percent in 2008, was by far the largest source of wind generation with more than three times that of California, the Nation's second-largest provider. Nationally, wind generation increased 60.7 percent from its 2007 level. 72.6 percent of the national increase was accounted for by increases in Texas, Colorado, Minnesota, Illinois, Oregon, and Iowa. Wood and wood-derived fuels, representing 0.9 percent of total net generation, accounted for 37 million MWh, down 4.4 percent from 2007. Geothermal power plants supplied 15 million MWh of net generation and other biomass plants generated 18 million MWh; each of these renewable sources accounted for approximately 0.4 percent of total net generation in 2008. Generation from solar thermal and photovoltaic sources was up 41.2 percent from 2007, at 864 thousand MWh. Wood and wood derived fuels and geothermal have maintained fairly stable output levels since 1997, averaging 38 million MWh and 15 million MWh per year, respectively. Other biomass generation has declined from a 23 million MWh peak in 2000 to 18 million MWh in 2008.

Net generation from conventional hydroelectric plants was up 3.0 percent from 248 million MWh in 2007 to 255 million MWh in 2008. Declines in California and Washington were offset by increases in Alabama, New York, and Arkansas. According to the National Climatic Data Center (NCDC), Arkansas had its sixth wettest spring on record in 2008. The largest increase in hydroelectric generation at a single plant in the United States was at the Bull Shoals facility in Arkansas. The absolute rise in hydroelectric generation at the Bull Shoals plant alone exceeded the increase at any other plant nationwide, as well as the increase in every other State (outside of Arkansas), except for Alabama and New York. In the West, March-October 2008 was the driest such eight-month period on record for California and Nevada, according to the NCDC. The largest drop at a single hydroelectric plant in the United States occurred at California's Edward C. Hyatt plant. The absolute decrease at Edward C. Hyatt exceeded the decreases in hydroelectric generation in every other State outside of California, other than Washington.

Largely due to a sharp rise in oil prices, petroleum-fired generation fell 29.7 percent, to 46 million MWh. Its share of total net generation dropped to 1.1 percent.

Fossil Fuel Stocks at Electric Power Plants

End-of-year coal stocks for 2008 increased 6.9 percent from 151 million tons to 162 million tons (Table 3.4). The 2008 build in coal stocks was similar to the 7.3 percent increase that occurred in 2007, with both considerably less than the 39.4 percent increase in 2006. The increase in 2008 appears to be the result of the decrease in coal-fired generation and the concomitant drop in coal consumption compared to 2007, as well as an increase in receipts of coal at electric power sector facilities The increase in end-of-year stocks is consistent with the finding in the North American Electric Reliability Corporation's (NERC) *2008/2009 Winter Reliability Assessment*[6] that power plant inventories "appear[ed] to be sufficient going into the winter, particularly with the softening of the international markets that will reduce exports and make importing coal economic again."

[6] http://www.nerc.com/files/Winter2008-09.pdf

Inventories of petroleum fell 5.7 percent from 47.2 million barrels at the end of 2007 to 44.5 million barrels at the end of 2008. This was the lowest end-of-year petroleum stock level since 2000, when stocks plummeted 24.4 percent from their 1999 year-end level.

Fuel Consumption

Consumption of fossil fuels for electricity generation decreased 0.4 percent (coal), 28.1 percent (petroleum), and 2.7 percent (natural gas) in 2008 (Table 3.1). This tracks with the similar pattern of decreases in generation for the same year: a 1.5 percent decrease in coal generation, 29.7 percent decrease in generation from petroleum, and 1.5 percent decrease in natural gas generation.

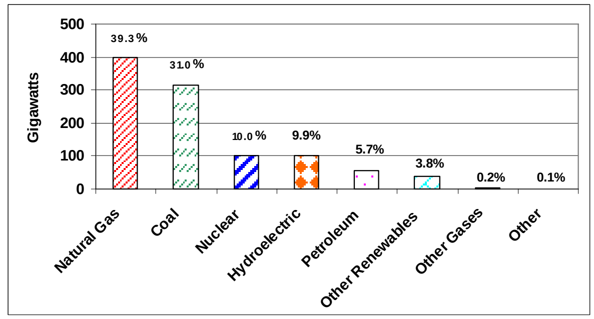
Consumption of fossil fuels by combined heat and power plants for useful thermal output is shown in Table 3.2[7]. Industrial and commercial power producers generally constitute a larger share of fuel consumption for useful thermal output than consumption for electricity generation. Commercial and industrial concerns showed more sensitivity to the weakened economy in 2008 than utilities: fossil fuel consumption for useful thermal output decreased 2.8 percent for coal, 39.2 percent for petroleum, and 9.1 percent for natural gas.

Capacity

Total U.S. net summer generating capacity as of December 31, 2008 was 1,010,171 MW (Figure ES2, Table 1.1), an increase of 1.5 percent from December 31, 2007. During the year, net summer generating capacity increased 15,283 MW, after accounting for retirements, deratings (reductions in power plant generating capability) and other adjustments. For the second year in a row, the net increase to renewable, non-hydroelectric capacity exceeded the net increase to fossil fuel capacity (counting retirements). New wind capacity made up the majority (53.2 percent) of the net summer capacity increase, at 8,136 MW. More new wind capacity came online in 2008 than in the prior two years combined. For most of the past decade, natural gas has been the preferred fuel for new generating capacity. However, in 2008, natural gas-fired generating units accounted for 4,556 MW, or 29.8 percent of the net increase in capacity.

[7] Please note that a new method of allocating fuel consumption between electricity generation and useful thermal output was applied to combined heat and power generators from 2004 forward. In the historical data, this results in the appearance of an increase in the efficiency of electricity generation after 2003.

Figure ES2. U.S. Electric Power Industry Net Summer Capacity, 2008



Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

As of December 31, 2008, wind generating capacity totaled 24,651 MW, a 49.3 percent increase over the 16,515 MW in operation at the end of 2007 (Table 1.1a). Texas continues to lead the Nation in wind power development with 2,938 MW of new wind capacity placed in service during 2008, increasing its share of the Nation's wind capacity currently in operation to 30.1 percent. Iowa has the second highest share of total installed wind generating capacity at 2,635 MW. The remainder of the top five wind-producing States are California at 9.6 percent, Minnesota at 5.9 percent and Washington at 5.5 percent of the Nation's total installed wind generating capacity. Collectively, 15,255 MW or 61.9 percent of total wind generating capacity is located in these 5 States. The States with the biggest increases in wind capacity in 2008 over 2007 include Michigan, South Dakota, Wisconsin, and West Virginia, all with a more than 200-percent increase. The States reporting wind capacity for the first time in 2008 include Indiana, New Hampshire, and Utah, with 130.5, 24.0, and 18.9 MW, respectively. Over the last three years 15,945 MW of wind generating capacity has been placed in service. The overall electric generating capacity from non-hydroelectric renewable energy sources increased 28.0 percent in 2008 to 38,493 MW (Figure ES2), with the additional wind capacity of 8,136 MW accounting for 96.6 percent of the increase.

Natural gas-fired generating capacity represented 397,432 MW or 39.3 percent of total net summer generating capacity in 2008. Although new natural gas-fired combined-cycle plants produce electricity more efficiently than older fossil-fueled plants, high natural gas prices can work against full utilization of these plants if such prices adversely affect economic dispatch. Since 1997, net summer natural gas-fired capacity increased by 220,961 MW, net of retirements and adjustments. As a result, natural gas capacity additions were almost equivalent to the 231,522 MW total increase in net summer capacity over the same time period. In contrast, coal, petroleum and nuclear capacity realized a combined decrease of 14,281 MW over the same time period. The net capacity increase of 24,843 MW from renewables, including hydro, other gases, and other sources accounts for the remainder of the additions since 1997.

Coal-fired generating capacity increased slightly in 2008 to 313,322 MW, or 31.0 percent of total generating capacity. This share of total capacity represents a 0.4 percentage point decline from 2007 (31.4 percent). Retirements of existing coal-fired net summer capacity reported by operators totaled 764 MW, while 1,482 MW were added during the year. This additional capacity is attributed to 2 existing plants and 3 new plants placed in service in 2008. Since 1997, net summer coal-fired capacity has declined 302 MW, after accounting for new additions, upgrades and other adjustments. Nevertheless, net generation from the Nation's coal-fired plants continues to increase due to gains in operating efficiency.

Nuclear net summer generating capacity totaled 100,755 MW or 10.0 percent of total capacity. Uprates totaling 383 MW of nameplate capacity were completed at the Three Mile Island plant in Pennsylvania, the Clinton Power Station and the Braidwood Generation Station in Illinois, as well as the Prairie Island and Monticello plants in Minnesota. Nuclear plant operators reported that net summer capacity increased by 489 MW and net winter capacity increased by 729 MW.

Conventional hydroelectric generating capacity accounted for 7.7 percent of total capacity with a summer net generating capacity of 77,930 MW. Pumped storage hydroelectric generating capacity totaled 21,858 MW. Combined, conventional and pumped storage generating capacity accounted for 9.9 percent of total capacity. Like coal and nuclear, hydroelectric generating capacity has remained relatively unchanged over the last 10 years.

Petroleum-fired capacity totaled 57,445 MW, up 1,377 MW (or 2.5 percent) from 2007. Petroleum-fired capacity accounted for 5.7 percent of all generating capacity.

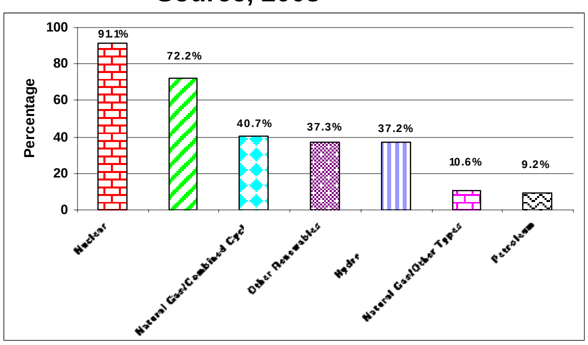
As of December 31, 2008, additions with a total nameplate capacity of 87,966 MW are scheduled to start commercial operation between 2009 and 2013 (Table 1.4). This compares with 92,996 MW of planned capacity reported on December 31, 2007, for the 5-year period through 2012. The data also show that over the next two years there will be a notable increase in planned additions relative to the past 2 years, if additions are completed as planned. In 2007 and 2008, the industry added 34,088 MW of nameplate capacity. Planned capacity additions to be placed in service during calendar years 2009 and 2010 total 46,940 MW. However, the weak economy, which has limited access to credit and capital, and lower demand may defer the installation of some of this capacity.

Capacity planning data also reveal an ongoing shift in the fuel mix. Natural gas, coal, and wind additions are projected to play a significant role over the next 5 years. The industry reports that it is planning to add 45,541 MW of natural-gas fired capacity. These planned additions account for 51.8 percent of planned additions over the next 5 years, and are projected to increase the overall natural gas-fired capacity by 10.0 percent. Over the same period, 21,340 MW of coal-fired capacity are planned. This amount represents 24.3 percent of total planned additions and is equivalent to 6.3 percent of existing coal-fired capacity. The Watts Bar Unit 2 nuclear reactor is planned for operation in 2012, adding 1,270 MW of nuclear capacity. This will be the first new reactor to go online since 1995[8]. Planned wind additions are projected to be 13,650 MW, or 15.5 percent of total additions, and would increase 2008 installed wind capacity by 54.6 percent. Planned solar additions, though only 2.2 percent of total planned additions, are notable in that the projected increase of 1,938 MW will expand the 2008 installed solar capacity by 360 percent.

[8] http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/states/statestn.html

As expected, nuclear and coal-fired plants have the highest average capacity factors at 91.1 percent and 72.2 percent, respectively (Figure ES3, Table 5.3)). This is consistent with the economies of scale that these forms of capital-intensive baseload generating plants provide. The average capacity factor for coal-fired generation reflects a 1.4-percentage point decrease from the 73.6 percent average capacity factor achieved in 2007. The average capacity factor for nuclear generation decreased from 91.8 percent to 91.1 percent. This compares to the 90.4 percent average over the past five years and the low of 72.0 percent that occurred in 1997. Because the industry continues to rely on new combined cycle natural gas generation to meet rising demand, the average capacity factor[9] rose from 33.5 percent in 2003 to 42.0 percent in 2007, falling off slightly to 40.7 percent in 2008. The 8.5 percentage point improvement in the average capacity factor reflects both the increased reliance on combined cycle generation to meet energy requirements and further efficiency gains in combined cycle generation technology. In 2008 the average capacity factor for simple cycle natural gas-fired generation was 10.6 percent.

Figure ES3. Average Capacity Factor by Energy Source, 2008



Sources: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Form EIA-923, "Power Plant Operations Report."

The increases in installed wind capacity are reflected in the reduced performance of renewable resources in aggregate, as measured by a composite capacity factor. The variable, intermittent nature of wind as an energy source leads to a low capacity factor relative to biomass, as wind is only available for generation subject to prevailing wind conditions. Renewable generation other than hydroelectric had a 37.3-percent capacity factor in 2008. This is a significant decrease from the 59.1 percent achieved in 2000, at which time the category was dominated by wood, wood-derived fuels, and other biomass, all of which are dispatchable energy sources. The continuous decline in the average capacity factor for all non-hydroelectric renewable resources is consistent with the significant growth of wind capacity relative to other forms of renewable electricity generation.

Fuel Switching Capacity

The total amount of net summer capacity reporting natural gas as the primary fuel in 2008 was 397,432 MW, of which 119,899 MW (30.2 percent) reported the operational capability as "switchable" between natural gas and oil. The requirement for this operational capability is that the capacity had (in working order) all necessary fuel switching equipment, including fuel storage. However, most of this capacity is subject to environmental regulatory limits on the use of oil, e.g., a restriction on how many hours per year a unit is allowed to burn oil. Of the 119,899 MW of gas-fired capacity that reported the ability to switch to oil, only 38,020 MW (31.7 percent) reported no environmental regulatory constraints or other factors limiting oil-fired operations (Table 1.9).

Fuel-switchable capacity is spread across the major generating technologies. Combustion turbine peaking units account for 44.9 percent (53,859 MW) of this net summer capacity. Steam generators (28,766 MW) and combined cycle units (36,339 MW) account for 24.0 percent and 30.3 percent of total switchable capacity, respectively. Internal combustion engines make up the remaining 0.8 percent. Of the total steam-electric switchable generating capacity, 16,777 MW can burn oil with no limiting factors. Similarly, for gas turbines, 15,167 MW of the total switchable capacity can switch fuels to oil without restriction.

Interconnection Costs

During 2008, 356 generators representing a total nameplate capacity of 16,947 MW were connected for the first time to the electric grid. Interconnection costs are presented by producer type (Table 1.11) and by voltage class (Table 1.12). Total cost for each individual generator interconnection varies based on its components. In turn, the components of the total cost may vary based on whether or not

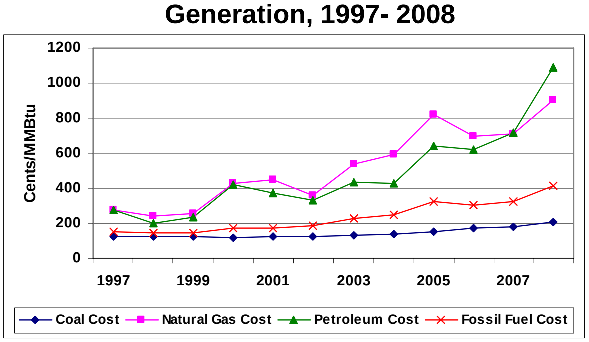
[9] Average capacity factors for natural gas generation have been calculated for both combined cycle generation and simple cycle generation. The required data was obtained from plant-specific capacity and energy data from the Form EIA-860, Form EIA-923, Form EIA-906 and Form EIA-920.

interconnection infrastructure was already in place, the type of equipment for which costs were incurred, or other factors associated with the relevant generator technology. Though the amount of capacity connected to the grid was about the same for both independent power producers (IPP) and electric utilities, the total cost for the IPP sector, as well as the cost per MW, was significantly greater. This was due in part to the high interconnection costs from new wind plants, which are typically sited in relatively remote locations, thereby requiring the construction of longer transmission line extensions than might be required for conventional power plants.

Fuel Costs

The 2008 average delivered cost for all fossil fuels used at electric power plants (coal, petroleum, and natural gas combined) for electricity generation was $4.11 per million British thermal units (MMBtu) (Figure ES4, Table 3.5), an increase of 27.2 percent over the average delivered cost of $3.23 per MMBtu in 2007. This is the largest increase since 2005. All fossil fuel prices increased in 2008. The cost of natural gas delivered to electric power plants increased 26.9 percent, from $7.11 per MMBtu in 2007 to $9.02 per MMBtu in 2008. Annually, there have been larger increases (e.g., the 51.4 percent increase between 2002 and 2003), but 2008 was a particularly volatile year for natural gas prices, which spiked in the summer of 2008. The average daily spot price at Henry Hub[10] peaked at $13.28 per MMBtu on July 2, and was down to $5.71 per MMBtu by December 31st. Petroleum costs followed a similar pattern in 2008, with a nationwide annual increase of 51.5 percent, from $7.17 MMBtu in 2007 to $10.87 per MMBtu in 2008. As a result, petroleum-fired generation was down 29.6 percent in 2008.

Figure ES4. Fuel Costs for Electricity Generation, 1997- 2008



Sources: U.S. Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," Federal Energy Regulatory Commission (FERC), Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," Form EIA-860, "Annual Electric Generator Report;" Form EIA-923, "Power Plant Operations Report."

[10] Natural gas price data from www.theice.com

The 2008 delivered cost of coal increased 16.9 percent nationwide, from $1.77 per MMBtu in 2007 to $2.07 MMBtu in 2008. This marked the eighth straight year that coal prices have increased. Since 2000 the delivered cost of coal has increased 72.5 percent (Figure ES4). Every Census Division saw increases in coal costs in 2008, with the exception of the Pacific Noncontiguous Division, as Alaska produces its own coal while Hawaii relies on imported coal. The South Atlantic and East South Central Divisions, which rely heavily on the higher-price Appalachian coal, saw the largest coal cost increases. In the South Atlantic, the delivered cost of coal increased 22.1 percent, from $2.38 per MMBtu in 2007 to $2.91 per MMBtu in 2008. In the East South Central, costs increased to $2.41 per MMBtu in 2008.

Emissions

The estimated carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxide (NO_x) emissions for electricity are based on the type and quantity of fossil fuels consumed by electric power plants for the generation of electric power and associated useful thermal output. In the case of SO_2 and NO_x, boiler configurations and pollution abatement equipment also play a role. The emissions factors used in the estimation methodology are described in the discussion of Air Emissions in the Technical Notes, and are summarized in Tables A1, A2, and A3.

Emissions estimates for CO_2, SO_2, and NO_x all declined in 2008 relative to the previous year, affected by the weak U.S. economy and the decline in electricity production (Table 3.9). SO_2 and NO_x emissions were further reduced due to increased installations of emission control devices.

Estimated carbon dioxide emissions by U.S. electric generators and combined heat and power facilities fell 2.5 percent from 2007 to 2008 (from 2,540 million metric tons to 2,477 million metric tons), largely due to a fall in fuel consumption at electric power plants. Emissions from coal-fired power plants typically account for four-fifths of CO_2 emissions by electric power plants. Coal-fired generation fell 1.5 percent in 2008.

SO_2 emissions fell 13.4 percent, from 9.0 to 7.8 million metric tons, between 2007 and 2008. This amounts to the largest year-over-year decline since 1995. There are multiple ways to reduce sulfur emissions in electricity production. One is to change the type of coal burned to a coal rank with lower sulfur content. Other methods are to switch fuels (typically to natural gas) or to shut down plants with high SO_2 emissions. The large reductions in SO_2 in 2008 mostly resulted from the installation of emissions reduction equipment (flue gas desulfurization (FGD) units) in response to recently-implemented emission reduction legislation.

In March 2005, the Environmental Protection Agency issued its Clean Air Interstate Rule (CAIR), which was intended to achieve the largest reduction in certain air pollutants in more than a decade. CAIR covers 28 Eastern States and the District of Columbia, a region that historically burned high-sulfur coal. CAIR calls for a 70-percent reduction in SO_2 (from 2003 levels) by 2015. Although CAIR was vacated and remanded to the EPA by a U.S. Court of Appeals for the District of Columbia in July 2008, it was later reinstated by the same court in December of 2008. The temporary remand of CAIR in 2008 may have put off some SO_2 abatement investments; however, much of the planned SO_2 control retrofits were already in the pipeline, as indicated by the elevated level of FGD installations in 2008. Furthermore, several States and the EPA have taken actions to reduce SO_2 outside of CAIR.

The recent reduction in SO_2 emissions is traceable to a significant increase in FGD unit installations during 2008. Nationwide, the count of FGD units increased from 279 to 330, reflecting the largest increase in installations since 1995[11]. Use of other SO_2 reduction methods was not significant enough to produce a sizable decline in SO_2 in 2008. Most of the decline in SO_2 emissions between 2007 and 2008 can be traced to coal-related SO_2 emissions, but coal consumption did not significantly change (decrease of 0.5 percent). Petroleum represents a small share of electricity generation and due to its smaller carbon content (relative to coal), its contribution to the decline in SO_2 emissions was far less significant than coal. Finally, between 2007 and 2008, the average sulfur content of coal used to fire electric power showed a marginal increase, while there was little switching among coal ranks during this time period.

2008 data also show significant reductions in NO_x emissions. This too can be traced to the installation of pollution abatement equipment such as low-NO_x burners and selective catalytic reduction devices. NO_x emissions decreased 8.8 percent (from 3.7 to 3.3 million metric tons) from 2007 to 2008.

[11]Title IV of the Clean Air Act Amendments of 1990 set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. Phase I of Title IV, which began in 1995, identified 110 mostly coal-burning electric power plants.

Trade

Total wholesale purchases of electric power in the United States increased 4.0 percent to 5,613 million MWh (Table 6.1), reversing a four-year downward trend. Almost half the volume of sales for resale was provided by energy-only providers (i.e., power marketing companies, a class of electric entities authorized by the Federal Energy Regulatory Commission (FERC) to transact at market-based rates, which came into being during the late 1990s with the deregulation of the wholesale power markets). Wholesale sales by wholesale power marketers and retail energy service providers increased from 2,477 million MWh in 2007 to 2,719 million MWh in 2008, which represented 47.9 percent of the wholesale market (Table 6.2). Independent power producers and combined heat and power (CHP) plants accounted for 24.4 percent of wholesale sales in 2008 compared to 25.5 percent in 2007.

The Nation's only international trade in electric power is with bordering nations Canada and Mexico, with the vast majority of that trade conducted with Canada. Most Mexican electric power trade is conducted with the State of California, while transactions with Canada are conducted through several bordering states. Much of the electricity provided from Canada is hydroelectric generation available for sale as the result of heavy seasonal river flows. On an annual basis, the U.S. is a net importer of electricity.

Total international net imports of electric power in 2008 increased 5.4 percent, from 31.3 million MWh in 2007 to 32.9 million MWh (Table 6.3). Imports to the

U.S. increased 5.6 million MWh in 2008 from 51.4 million MWh in 2007 to 57.0 million MWh, while exports increased by 3.9 million MWh. Imports from Canada increased from 50.1 million MWh in 2007 to 55.7 million MWh in 2008, and U.S. exports to Canada increased from 19.6 million MWh to 23.5 million MWh. Electricity trade with Mexico followed a similar pattern of net imports, increasing only fractionally from 2007.

Electricity Prices and Sales

In 2008, the average retail price for all customers rose 0.61 cents per kWh to 9.74 cents per kWh (Table 7.4). This amounted to a 6.7-percent increase over the 9.13 cents per kWh average retail price paid in 2007. Year-over-year, the average retail price for all customers increased in 47 of the 50 States as well as the District of Columbia, with the exceptions being California, Maine, and Nevada. From 2007 to 2008, the average price of electricity increased 10 percent or more in 15 States. Most of the increases were in the 10 to 13 percent range, with the largest increase, 22.0 percent, occurring in Rhode Island. The average retail electric price for all customers declined in only 3 States compared to 11 States in 2007, and only Maine and California had decreases of more than 1 percent. The average retail price of electricity to all customers increased by 4 percent or more in all Census Divisions of the country—except the Pacific Contiguous, which was led by a 2.0 percent decrease in California. In New Jersey the average retail rate for all customers increased 11.0 percent. In the District of Columbia the average price increased 13.4 percent and in Texas it increased 8.7 percent. In Louisiana, the average electricity price for all customers increased 12.5 percent. Most Census Divisions experienced increases of 4 to 9 percent in the average retail price for all customers, with the exception of the East South Central Census Division, which experienced an increase of 12.3 percent. The highest regional price increase was in the Pacific Non-Contiguous Census Division (Alaska and Hawaii), where the average electricity price to all customers increased 29.7 percent over 2007. While both States rely heavily on oil and refined oil products, the regional price increase was primarily driven by increases in Hawaii. Hawaii's primary fuel for electricity is petroleum, and petroleum prices to that State increased 42.0 percent in 2008.

In 2008, residential prices increased to 11.26 cents per kWh, or 5.7 percent over 2007. The average residential price increased by 10 percent or more in 8 States and the District of Columbia. Most of these jurisdictions have implemented retail competition and the investor-owned utilities operating within these States participate in organized, competitive wholesale markets operated by independent system operators. Residential prices in Rhode Island increased 24.1 percent, from 14.05 cents per kWh in 2007 to 17.43 cents per kWh in 2008. The average residential price in Maryland increased 16.4 percent, from 11.89 cents per kWh in 2007 to 13.84 cents per kWh in 2008. The largest increase in average residential prices was in Hawaii, at 34.7 percent. The increases in Rhode Island and Maryland are the result of the transition to market based rates for the wholesale electricity portion of retail electric service. In order to mitigate the impact of higher retail prices, the Maryland Public Service Commission approved a plan for the largest investor-owned utility in the State that gave customers two payment options. The first option provided for retail prices based on the full market price of wholesale electricity prices, effective June 1, 2008. This option resulted in approximately a 50-percent increase in the average electric bill. The second option provided that the cost of electricity would be phased in over time. Deferred costs would be recovered by December 31, 2009.[12]

The District of Columbia had the fourth largest increase in residential prices, at 13.2 percent, followed by New Jersey (10.8 percent). On a regional basis, the highest average residential price increase was observed

[12] In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan Pursuant to Section 7-548 of the Public Utility companies Article and the Commission's Inquiry into Factors Impacting Wholesale Electricity Prices, Source: Maryland Public Service Commission, Order No. 81423. Case No. 9099, May 23, 2008.

in the East South Central Division. New England, Mid-Atlantic, East North Central, South Atlantic, and West South Central all observed increases of between 6 percent and 7 percent. Average residential prices in the New England and Mid-Atlantic Census Divisions increased 6.0 percent and 6.8 percent respectively. Average residential prices fell 1.9 percent in Maine and 4.2 percent in California. These were the only two States to realize a decrease in the residential average retail price of electricity in 2008.

Nationally, average commercial prices increased from 9.65 to 10.36 cents per kWh, a 7.5 percent increase over 2007. The largest regional price increase was in the Pacific Noncontiguous Census Division, at 28.0 percent, followed by a 14.8 percent increase in the East North Central Census Division. By State, the largest increase in average commercial prices was in Illinois, where prices increased 37.6 percent as result of some Illinois utilities reclassifying higher-priced industrial transactions as commercial in 2008. Illinois was followed by increases in Hawaii (35.7 percent), Rhode Island (21.2 percent), Virginia (14.7 percent), Georgia (12.4 percent) and the District of Columbia (12.1 percent). The average commercial price in the East North Central Census Division was 9.75 cents per kWh in 2008, up from 8.49 in 2007. In 2007, the West South Central Census Division was unchanged at 9.26 cents per kWh but increased 9.2 percent in 2008 to 10.11 cents per kWh. The average commercial price declined less than 1 percent in Nevada and 2.2 percent in California. In the Pacific Contiguous Census Division, the average commercial price declined from 11.19 cents per kWh in 2007 to 11.03 cents per kWh in 2008. This was the only region where average commercial prices declined.

Average industrial prices increased 6.9 percent from 6.39 cents per kWh in 2007 to 6.83 cents per kWh in 2008. The largest regional price increase in the industrial sector was in the Pacific Noncontiguous Census Division, at 36.1 percent, with Hawaii observing an increase of 41.7 percent from 18.38 cents per kWh to 26.05 cents per kWh in 2008. Average industrial prices in the District of Columbia increased 33.7 percent followed by increases in Louisiana and Tennessee (both at 21.2 percent), and Georgia (20.6 percent). The average industrial rate in the East North Central Census Division was 5.79 cents per kWh in 2008, a 1.9 percent decrease from 5.90 cents per kWh in 2007. This was driven by a 31.3-percent decrease in Illinois industrial prices, as a result of reclassifying data.

Total U.S. retail sales of electricity were 3,733 million MWh in 2008, a 0.8 percent decrease from 2007 to 2008. Comparatively, the annual growth in electricity sales in 2007 was 2.6 percent, and the average annual growth rate since 1997 was 1.6 percent. The 2008 decrease in annual sales from 2007 marks the first time since 2001 that annual sales decreased from the prior year. This decrease was driven by the residential and industrial sectors, with sales decreases of 0.9 percent and 1.8 percent, respectively. Commercial sales were essentially flat between 2007 and 2008. Since 1997, annual industrial sales have declined four times and overall, load continues to gradually shift away from the industrial sector. The industrial sector accounted for 33.0 percent of total retail sales in 1997, but by 2008 it had declined to 27.0 percent. Over that same time period, the commercial sector's share of retail sales increased from 29.5 percent to 35.8 percent, while retail sales to the residential sector grew from 34.2 percent to 37.0 percent.

Demand-Side Management

In 2008, electricity providers reported total peak-load reductions of 32,741 MW resulting from demand-side management (DSM) programs, an 8.2 percent increase from the amount reported in 2007 (Table 9.1). Reported DSM costs increased $1.2 billion, up 47.4 percent from the $2.5 billion reported in 2007. DSM costs can vary significantly from year to year because of business cycle fluctuations and regulatory changes. Since costs are reported as they occur, while program effects may appear in future years, DSM costs and effects may not always show a direct relationship. In the five years since 2003, nominal DSM expenditures have increased at a 22.9-percent average annual growth rate. During the same period, actual peak load reductions have grown at a 6.17-percent average annual rate from, 22,904 MW to 32,741 MW. The divergence between the growth rates of load reduction and expenditures is driven in large measure by 2008 expenditures, which are in response to higher overall energy prices. The full effect of these expenditures may appear in additional load reductions in the coming years. The combined DSM energy savings programs (i.e., load management and energy efficiency) increased to 87.8 million MWh in 2008 from 69.0 million MWh in 2007.

Table ES1. Summary Statistics for the United States, 1997 through 2008

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Net Generation (thousand megawatthours)												
Coal[1]	1,985,801	2,016,456	1,990,511	2,012,873	1,978,301	1,973,737	1,933,130	1,903,956	1,966,265	1,881,087	1,873,516	1,845,016
Petroleum[2]	46,243	65,739	64,166	122,225	121,145	119,406	94,567	124,880	111,221	118,061	128,800	92,555
Natural Gas[3]	882,981	896,590	816,441	760,960	710,100	649,908	691,006	639,129	601,038	556,396	531,257	479,399
Other Gases[4]	11,707	13,453	14,177	13,464	15,252	15,600	11,463	9,039	13,955	14,126	13,492	13,351
Nuclear	806,208	806,425	787,219	781,986	788,528	763,733	780,064	768,826	753,893	728,254	673,702	628,644
Hydroelectric Conventional[5]	254,831	247,510	289,246	270,321	268,417	275,806	264,329	216,961	275,573	319,536	323,336	356,453
Other Renewables[6]	126,212	105,238	96,525	87,329	83,067	79,487	79,109	70,769	80,906	79,423	77,088	77,183
Wind	55,363	34,450	26,589	17,811	14,144	11,187	10,354	6,737	5,593	4,488	3,026	3,288
Solar Thermal and Photovoltaic	864	612	508	550	575	534	555	543	493	495	502	511
Wood and Wood Derived Fuels[7]	37,300	39,014	38,762	38,856	38,117	37,529	38,665	35,200	37,595	37,041	36,338	36,948
Geothermal	14,951	14,637	14,568	14,692	14,811	14,424	14,491	13,741	14,093	14,827	14,774	14,726
Other Biomass[8]	17,734	16,525	16,099	15,420	15,421	15,812	15,044	14,548	23,131	22,572	22,448	21,709
Pumped Storage[9]	-6,288	-6,896	-6,558	-6,558	-8,488	-8,535	-8,743	-8,823	-5,539	-6,097	-4,467	-4,040
Other[10]	11,692	12,231	12,974	12,821	14,232	14,045	13,527	11,906	4,794	4,024	3,571	3,612
All Energy Sources	**4,119,388**	**4,156,745**	**4,064,702**	**4,055,423**	**3,970,555**	**3,883,185**	**3,858,452**	**3,736,644**	**3,802,105**	**3,694,810**	**3,620,295**	**3,492,172**
Net Summer Generating Capacity (megawatts)												
Coal[1]	313,322	312,738	312,956	313,380	313,020	313,019	315,350	314,230	315,114	315,496	315,786	313,624
Petroleum[2]	57,445	56,068	58,097	58,548	59,119	60,730	59,651	66,162	61,837	60,069	66,282	72,463
Natural Gas[3]	397,432	392,876	388,294	383,061	371,011	355,442	312,512	252,832	219,590	195,119	180,288	176,471
Other Gases[4]	1,995	2,313	2,256	2,063	2,296	1,994	2,008	1,670	2,342	1,909	1,520	1,525
Nuclear	100,755	100,266	100,334	99,988	99,628	99,209	98,657	98,159	97,860	97,411	97,070	99,716
Hydroelectric Conventional[5]	77,930	77,885	77,821	77,541	77,641	78,694	79,356	78,916	79,359	79,393	79,151	79,415
Other Renewables[6]	38,493	30,069	24,113	21,205	18,717	18,153	16,710	16,101	15,572	15,942	15,444	15,351
Wind	24,651	16,515	11,329	8,706	6,456	5,995	4,417	3,864	2,377	2,252	1,720	1,610
Solar Thermal and Photovoltaic	536	502	411	411	398	397	397	392	386	389	335	334
Wood and Wood Derived Fuels[7]	6,864	6,704	6,372	6,193	6,182	5,871	5,844	5,882	6,147	6,795	6,802	6,924
Geothermal	2,256	2,214	2,274	2,285	2,152	2,133	2,252	2,216	2,793	2,846	2,893	2,893
Other Biomass[11]	4,186	4,134	3,727	3,609	3,529	3,758	3,800	3,748	3,869	3,660	3,694	3,590
Pumped Storage[9]	21,858	21,886	21,461	21,347	20,764	20,522	20,371	19,664	19,522	19,565	19,518	19,310
Other[12]	942	788	882	887	746	684	686	519	523	1,023	810	774
All Energy Sources	**1,010,171**	**994,888**	**986,215**	**978,020**	**962,942**	**948,446**	**905,301**	**848,254**	**811,719**	**785,927**	**775,868**	**778,649**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	744,151	766,786[R]	776,479[R]	746,470	692,908	696,752	696,376	674,833	680,941	653,857	638,086	618,389
Capacity Resources (megawatts)[13]	909,504	914,397[R]	891,226[R]	882,125	875,870	856,131	833,380	788,990	808,054	765,744	744,670	737,855
Capacity Margins (percent)[13]	18.2	16.1[R]	12.9[R]	15.4	20.9	18.6	16.4	14.5	15.7	14.6	14.3	16.2
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	1,042,335	1,046,795	1,030,556	1,041,448	1,020,523	1,014,058	987,583	972,691	994,933	949,802	946,295	931,949
Petroleum (thousand barrels)[2]	80,932	112,615	110,634	206,785	203,494	206,653	168,597	216,672	195,228	207,871	222,640	159,715
Natural Gas (millions of cubic feet)[3]	6,895,843	7,089,342	6,461,615	6,036,370	5,674,580	5,616,135	6,126,062	5,832,305	5,691,481	5,321,984	5,081,384	4,564,770
Other Gases (millions of Btu)[4]	96,757	114,904	114,665	109,916	135,144	156,306	131,230	97,308	125,971	126,387	124,988	119,412
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	22,168	22,810	23,227	23,833	24,275	17,720	17,561	18,944	20,466	20,373	20,320	21,005
Petroleum (thousand barrels)[2]	12,016	19,775	20,371	24,408	25,870	17,939	14,811	18,268	22,266	26,822	28,845	28,802
Natural Gas (millions of cubic feet)[3]	793,537	872,579	942,817	984,340	1,052,100	721,267	860,019	898,286	985,263	982,958	949,106	868,569
Other Gases (millions of Btu)[4]	203,236	214,321	226,464	238,396	218,295	137,837	146,882	166,161	230,082	223,713	208,828	187,680
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	1,064,503	1,069,606	1,053,783	1,065,281	1,044,798	1,031,778	1,005,144	991,635	1,015,398	970,175	966,615	952,955
Petroleum (thousand barrels)[2]	92,948	132,389	131,005	231,193	229,364	224,593	183,408	234,940	217,494	234,694	251,486	188,517
Natural Gas (millions of cubic feet)[3]	7,689,380	7,961,922	7,404,432	7,020,709	6,726,679	6,337,402	6,986,081	6,730,591	6,676,744	6,304,942	6,030,490	5,433,338
Other Gases (millions of Btu)[4]	299,993	329,225	341,129	348,312	353,438	294,143	278,111	263,469	356,053	350,100	333,816	307,092
Stocks at Electric Power Sector Facilities (year end)												
Coal (thousand tons)[14]	161,589	151,221	140,964	101,137	106,669	121,567	141,714	138,496	102,296	141,604	120,501	98,826
Petroleum (thousand barrels)[15]	44,498	47,203	51,583	50,062	51,434	53,170	52,490	57,031	40,932	54,109	56,591	51,138
Receipts of Fuel at Electricity Generators[16]												
Coal (thousand tons)[1]	1,069,709	1,054,664	1,079,943	1,021,437	1,002,032	986,026	884,287	762,815	790,274	908,232	929,448	880,588
Petroleum (thousand barrels)[2]	96,341	88,347	100,965	194,733	186,655	185,567	120,851	124,618	108,272	145,939	181,276	128,749
Natural Gas (millions of cubic feet)[17]	7,879,046	7,200,316	6,675,246	6,181,717	5,734,054	5,500,704	5,607,737	2,148,924	2,629,986	2,809,455	2,922,957	2,764,734
Cost of Fuel at Electricity Generators (cents per million Btu)[16]												
Coal[1]	207	177	169	154	136	128	125	123	120	122	125	127
Petroleum[2]	1,087	717	623	644	429	433	334	369	418	236	202	273
Natural Gas[17]	902	711	694	821	596	539	356	449	430	257	238	276
Emissions (thousand metric tons)												
Carbon Dioxide (CO_2)	2,477,213	2,539,805[R]	2,481,829[R]	2,536,675[R]	2,479,971[R]	2,438,338[R]	2,417,327[R]	2,412,030[R]	2,464,550[R]	2,360,424[R]	2,345,951[R]	2,253,783[R]
Sulfur Dioxide (SO_2)[18]	7,830	9,042	9,524	10,340	10,309	10,646	10,881	11,174	11,963	12,843	13,464	13,480
Nitrogen Oxides (NO_X)[18]	3,330	3,650	3,799	3,961	4,143	4,532	5,194	5,290	5,638	5,955	6,459	6,500
Trade (million megawatthours)												
Purchases	5,613	5,411	5,503	6,092	6,999	6,980	8,755	7,555	2,346	2,040	2,021	1,966
Sales for Resale	5,681	5,479	5,493	6,072	6,759	6,921	8,569	7,345	2,355	1,998	1,922	1,839
Electricity Imports and Exports (thousand megawatthours)												
Imports	57,021	51,396	42,691	44,527	34,210	30,395	36,779	38,500	48,592	43,215	39,513	43,031
Exports	24,083	20,144	24,271	19,791	22,898	23,975	15,796	16,473	14,829	14,222	13,656	8,974

See end of table for Notes and Sources.

Table ES1. Summary Statistics for the United States, 1997 through 2008
(Continued)

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	124,937	123,950	122,471	120,761	118,764	117,280	116,622	114,890	111,718	110,383	109,048	107,066
Commercial	17,563	17,377	17,172	16,872	16,607	16,550	15,334	14,867	14,349	14,074	13,887	13,542
Industrial	775	794	760	734	748	713	602	571	527	553	540	563
Transportation	1	1	1	1	1	1	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	1,067	1,030	974	935	933	952
All Sectors	143,276	142,122	140,404	138,367	136,119	134,544	133,624	131,359	127,568	125,945	124,408	122,123
Sales to Ultimate Customers (thousand megawatthours)												
Residential	1,379,981	1,392,241	1,351,520	1,359,227	1,291,982	1,275,824	1,265,180	1,201,607	1,192,446	1,144,923	1,130,109	1,075,880
Commercial	1,335,981	1,336,315	1,299,744	1,275,079	1,230,425	1,198,728	1,104,497	1,083,069	1,055,232	1,001,996	979,401	928,633
Industrial	1,009,300	1,027,832	1,011,298	1,019,156	1,017,850	1,012,373	990,238	996,609	1,064,239	1,058,217	1,051,203	1,038,197
Transportation	7,700	8,173	7,358	7,506	7,224	6,810	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	105,552	113,174	109,496	106,952	103,518	102,901
All Sectors	3,732,962	3,764,561	3,669,919	3,660,969	3,547,479	3,493,734	3,465,466	3,394,458	3,421,414	3,312,087	3,264,231	3,145,610
Direct Use	173,481	159,254	146,927	150,016	168,470	168,295	166,184	162,649	170,943	171,629	160,866	156,239
Total Disposition	3,906,443	3,923,814	3,816,845	3,810,984	3,715,949	3,662,029	3,631,650	3,557,107	3,592,357	3,483,716	3,425,097	3,301,849
Revenue From Ultimate Customers (million dollars)												
Residential	155,433	148,295	140,582	128,393	115,577	111,249	106,834	103,158	98,209	93,483	93,360	90,704
Commercial	138,469	128,903	122,914	110,522	100,546	96,263	87,117	85,741	78,405	72,771	72,575	70,497
Industrial	68,920	65,712	62,308	58,445	53,477	51,741	48,336	50,293	49,369	46,846	47,050	47,023
Transportation	827	792	702	643	519	514	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	7,124	8,151	7,179	6,796	6,863	7,110
All Sectors	363,650	343,703	326,506	298,003	270,119	259,767	249,411	247,343	233,163	219,896	219,848	215,334
Average Retail Price (cents per kilowatthour)												
Residential	11.26	10.65	10.40	9.45	8.95	8.72	8.44	8.58	8.24	8.16	8.26	8.43
Commercial	10.36	9.65	9.46	8.67	8.17	8.03	7.89	7.92	7.43	7.26	7.41	7.59
Industrial	6.83	6.39	6.16	5.73	5.25	5.11	4.88	5.05	4.64	4.43	4.48	4.53
Transportation	10.74	9.70	9.54	8.57	7.18	7.54	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	6.75	7.20	6.56	6.35	6.63	6.91
All Sectors	9.74	9.13	8.90	8.14	7.61	7.44	7.20	7.29	6.81	6.64	6.74	6.85
Revenue and Expense Statistics (million dollars)												
Major Investor Owned												
Utility Operating Revenues	298,962	278,499[R]	275,501[R]	265,652[R]	238,759[R]	230,151[R]	219,609[R]	267,276[R]	233,915[R]	213,090[R]	214,849[R]	209,022[R]
Utility Operating Expenses	267,263	248,039[R]	245,589[R]	236,786[R]	206,960[R]	201,057[R]	189,062[R]	234,910[R]	210,250[R]	180,467[R]	183,954[R]	177,798[R]
Net Utility Operating Income	31,699	30,460[R]	29,912[R]	28,866[R]	31,799[R]	29,094[R]	30,548[R]	32,366[R]	23,665[R]	32,623[R]	30,896[R]	31,225[R]
Major Publicly Owned (with Generation Facilities)												
Operating Revenues	NA	NA	NA	NA	NA	33,906	32,776	38,028	31,843	26,767	26,155	25,397
Operating Expenses	NA	NA	NA	NA	NA	29,637	28,638	32,789	26,244	21,274	20,880	20,425
Net Electric Operating Income	NA	NA	NA	NA	NA	4,268	4,138	5,238	5,598	5,493	5,275	4,972
Major Publicly Owned (without Generation Facilities)												
Operating Revenues	NA	NA	NA	NA	NA	12,454	11,546	10,417	9,904	9,354	8,790	8,586
Operating Expenses	NA	NA	NA	NA	NA	11,481	10,703	9,820	9,355	8,737	8,245	8,033
Net Electric Operating Income	NA	NA	NA	NA	NA	974	843	597	549	617	545	552
Major Federally Owned												
Operating Revenues	NA	NA	NA	NA	NA	11,798	11,470	12,458	10,685	10,186	9,780	8,833
Operating Expenses	NA	NA	NA	NA	NA	8,763	8,665	10,013	8,139	7,775	7,099	5,999
Net Electric Operating Income	NA	NA	NA	NA	NA	3,035	2,805	2,445	2,546	2,411	2,681	2,834
Major Cooperative Borrower Owned												
Operating Revenues	42,076	38,208	36,723	34,088	30,650	29,228	27,458	26,458	25,629	23,824	23,988	23,321
Operating Expenses	38,498	34,843	33,550	31,209	27,828	26,361	24,561	23,763	22,982	21,283	21,223	20,715
Net Electric Operating Income	3,578	3,365	3,173	2,879	2,822	2,867	2,897	2,696	2,647	2,541	2,764	2,606
Demand-Side Management (DSM) Data[19]												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction	32,741	30,253[R]	27,240	25,710	23,532	22,904	22,936	24,955	22,901	26,455	27,231	25,284
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	86,001	67,134	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453
Load Management	1,824	1,857[R]	865	1,006	2,047	2,020	1,790	990	875	872	392	953
DSM Cost (million dollars)												
Total Cost	3,720	2,523[R]	2,051	1,921	1,557	1,297	1,626	1,630	1,565	1,424	1,421	1,636

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal are included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology) and waste oil.
[3] Includes a small number of generators for which waste heat is the primary energy source.
[4] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[5] Conventional hydroelectric power excluding pumped storage facilities.
[6] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.
[7] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[8] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[9] Pumped storage is the capacity to generate electricity from water previously pumped to an elevated reservoir and then released through a conduit to turbine generators located at a lower level. The generation from a hydroelectric pumped storage facility is the net value of production minus the energy used for pumping..
[10] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[11] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[12] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[13] 2008 data updated June 2010.
[14] Anthracite, bituminous, subbituminous, lignite, and synthetic coal; excludes waste coal.
[15] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology). Data prior to 2004 includes small quantities of waste oil.
[16] For 2002 through 2007, includes data from the Form EIA-423 for independent power producers, and commercial and industrial power-producing facilities. Beginning in 2008, data are collected on the Form EIA-923 for utilities, independent power producers, and commercial and industrial power-producing facilities. Receipts, cost, and quality data are collected from plants above a 50 MW threshold, and imputed for plants between 1 and 50 MW. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.
[17] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately.
[18] SO2 and NOx 2008 values are preliminary.
[19] Data presented are reflective of large utilities.
NA = Not available.
R = Revised.
Note: ·See Glossary reference for definitions.·See Technical Notes Table A5 for conversion to different units of measure.·Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.·Dual-fired capacity returned to respective fuel categories for current and all historical years. New fuel switchable capacity tables have replaced dual-fired breakouts.·Totals may not equal sum of components because of indep
Sources: U.S. Energy Information Administration Form EIA-411, "Coordinated Bulk Power Supply Program Report;" Form EIA-412, "Annual Electric Industry Financial Report" The Form EIA-412 was terminated in 2003; Form EIA-767, "Steam-Electric Plant Operation and Design Report" was suspended; Form EIA-860, "Annual Electric Generator Report;" Form EIA-861, "Annual Electric Power Industry Report;" Form EIA-923, "Power Plant Operations Report" replaces several form(s) including: Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report; and FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," and their predecessor forms. Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Utilities, Licensees and Others;" FERC Form 1-F, "Annual Report for Nonmajor Public Utilities and Licensees;" Rural Utilities Service (RUS) Form 7, "Operating Report;" RUS Form 12, "Operating Report;" Imports and Exports: DOE, Office of Electricity Delivery and Energy Reliability, Form OE-781R, " Annual Report of International Electric Export/Import Data," predecessor forms, and National Energy Board of Canada. For 2001 forward, data from the California Independent System Operator are used in combination with the Form OE-781R values to estimate electricity trade with Mexico.

Table ES2. Supply and Disposition of Electricity, 1997 through 2008
(Million Megawatthours)

Category	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Supply												
Generation												
Electric Utilities	2,475	2,504	2,484	2,475	2,505	2,462	2,549	2,630	3,015	3,174	3,212	3,123
Independent Power Producers	1,332	1,324	1,259	1,247	1,119	1,063	955	781	458	201	91	59
Combined Heat and Power, Electric	167	177	165	180	184	196	194	170	165	155	154	148
Electric Power Sector Generation Subtotal	3,974	4,005	3,908	3,902	3,808	3,721	3,698	3,580	3,638	3,530	3,457	3,329
Combined Heat and Power, Commercial	8	8	8	8	8	7	7	7	8	9	9	9
Combined Heat and Power, Industrial	137	143	148	145	154	155	153	149	157	156	154	154
Industrial and Commercial Generation Subtotal	145	151	157	153	162	162	160	157	165	165	163	163
Total Net Generation	4,119	4,157	4,065	4,055	3,971	3,883	3,858	3,737	3,802	3,695	3,620	3,492
Total Imports	57	51	43	45	34	30	37	39	49	43	40	43
Total Supply	**4,176**	**4,208**	**4,107**	**4,100**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**
Disposition												
Retail Sales												
Full-Service Providers	3,434	3,468	3,438	3,413	3,318	3,285	3,324	3,297	3,310	3,236	3,240	3,140
Energy-Only Providers	286	283	219	237	222	189	141	98	112	76	24	6
Facility Direct Retail Sales	14	14	12	11	8	20	NA	NA	NA	NA	NA	NA
Total Electric Industry Retail Sales	3,733	3,765	3,670	3,661	3,547	3,494	3,465	3,394	3,421	3,312	3,264	3,146
Direct Use	173	159	147	150	168	168	166	163	171	172	161	156
Total Exports	24	20	24	20	23	24	16	16	15	14	14	9
Losses and Unaccounted For	246	264	266	269	266	228	248	202	244	240	221	224
Total Disposition	**4,176**	**4,208**	**4,107**	**4,100**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**

NA = Not available.

Notes: • Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions. Losses and Unaccounted For includes: (1) reporting by utilities and power marketers that represent losses incurred in transmission and distribution, as well as volumes unaccounted for in their own energy balance; and (2) discrepancies among the differing categories upon balancing the table. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-861, "Annual Electric Power Industry Report;" and predecessor forms. Imports and Exports: Mexico data - DOE, Fossil Fuels, Office of Fuels Programs, Form OE-781R, "Annual Report of International Electrical Export/Import Data:" Canada data - National Energy Board of Canada (metered energy firm and interruptible).

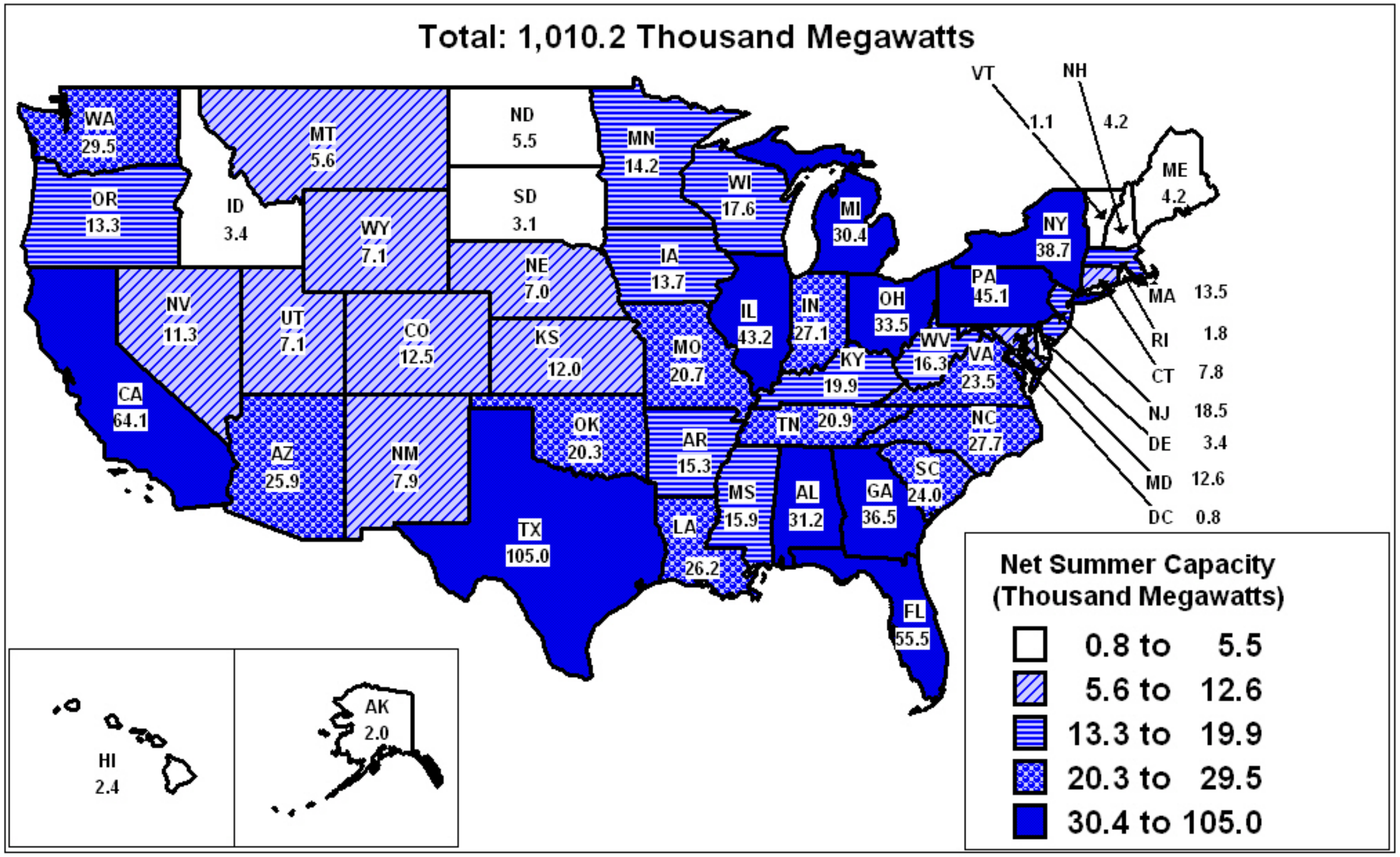
Chapter 1. Capacity

Table 1.1. Existing Net Summer Capacity by Energy Source and Producer Type, 1997 through 2008
(Megawatts)

Period	Coal[1]	Petroleum [2]	Natural Gas[3]	Other Gases[4]	Nuclear	Hydroelectric Conventional[5]	Other Renewables[6]	Hydroelectric Pumped Storage[7]	Other[8]	Total
Total (All Sectors)										
1997	313,624	72,463	176,471	1,525	99,716	79,415	15,351	19,310	774	778,649
1998	315,786	66,282	180,288	1,520	97,070	79,151	15,444	19,518	810	775,868
1999	315,496	60,069	195,119	1,909	97,411	79,393	15,942	19,565	1,023	785,927
2000	315,114	61,837	219,590	2,342	97,860	79,359	15,572	19,522	523	811,719
2001	314,230	66,162	252,832	1,670	98,159	78,916	16,101	19,664	519	848,254
2002	315,350	59,651	312,512	2,008	98,657	79,356	16,710	20,371	686	905,301
2003	313,019	60,730	355,442	1,994	99,209	78,694	18,153	20,522	684	948,446
2004	313,020	59,119	371,011	2,296	99,628	77,641	18,717	20,764	746	962,942
2005	313,380	58,548	383,061	2,063	99,988	77,541	21,205	21,347	887	978,020
2006	312,956	58,097	388,294	2,256	100,334	77,821	24,113	21,461	882	986,215
2007	312,738	56,068	392,876	2,313	100,266	77,885	30,069	21,886	788	994,888
2008	313,322	57,445	397,432	1,995	100,755	77,930	38,493	21,858	942	1,010,171
Electricity Generators, Electric Utilities										
1997	302,866	69,557	141,713	206	99,716	76,177	2,123	19,310	222	711,889
1998	299,739	62,704	130,404	55	97,070	75,525	2,067	18,898	229	686,692
1999	277,780	49,020	123,192	220	95,030	74,122	790	18,945	224	639,324
2000	260,990	41,032	123,665	57	85,968	73,738	837	18,020	13	604,319
2001	244,451	38,456	112,841	57	63,060	72,968	979	17,097	13	549,920
2002	244,056	33,876	127,692	61	63,202	73,391	989[R]	17,807	--	561,074
2003	236,473	32,570	125,612	61	60,964	72,827	925	17,803	13	547,249
2004	235,976	31,415	131,734	58	60,651	71,696	960	18,048	13	550,550
2005	229,705	30,867	147,752	--	56,564	71,568	1,545	18,195	39	556,235
2006	230,644	30,419	157,742	104	56,143	71,840	2,291	18,301	39	567,523
2007	231,289	29,115	162,756	104	54,211	72,186	2,806	18,693	39	571,200
2008	231,857	30,657	173,106	--	54,376	72,142	4,066	18,664	39	584,908
Electricity Generators, Independent Power Producers										
1997	719	639	2,996	--	--	2,103	6,695	--	--	13,153
1998	6,132	1,463	17,051	--	--	2,454	6,955	620	--	34,675
1999	27,725	8,508	38,553	--	2,381	4,142	8,794	620	--	90,724
2000	44,164	18,771	60,327	--	11,892	4,509	8,994	1,502	--	150,159
2001	60,701	25,311	102,693	--	35,099	4,885	9,894	2,567	79	241,230
2002	61,770	23,664	140,404	9	35,455	4,911	10,390[R]	2,564	80	279,246
2003	66,538	26,028	178,624	6	38,244	5,058	11,786	2,719	46	329,049
2004	67,242	25,918	190,855	8	38,978	5,274	12,070	2,717	46	343,106
2005	73,734	26,041	188,043	12	43,424	5,284	13,864	3,152	46	353,601
2006	72,730	25,384	184,196	20	44,190	5,263	15,865	3,160	46	350,854
2007	71,943	24,818	184,888	8	46,055	5,346	21,002	3,193	26	357,278
2008	71,864	24,823	179,141	--	46,379	5,433	28,166	3,193	46	359,044
Combined Heat and Power, Electric Power										
1997	4,895	810	18,660	5	--	--	707	--	--	25,076
1998	5,021	800	19,632	--	--	--	749	--	--	26,202
1999	5,230	1,097	19,390	--	--	--	741	--	--	26,459
2000	5,044	907	20,704	262	--	--	736	--	--	27,653
2001	4,628	972	21,226	287	--	1	498	--	28	27,639
2002	5,222	1,084	28,455	182	--	--	555	--	--	35,499
2003	5,534	1,051	34,895	185	--	1	665	--	--	42,332
2004	5,609	677	32,600	289	--	1	555	--	--	39,731
2005	5,560	530	31,740	289	--	1	614	--	--	38,735
2006	5,837	970	30,031	325	--	1	628	--	--	37,793
2007	5,885	907	29,468	339	--	--	656	--	--	37,254
2008	5,927	900	29,575	206	--	--	701	--	--	37,309
Combined Heat and Power, Commercial[9]										
1997	314	380	1,157	--	--	32	450	--	--	2,333
1998	317	282	1,188	--	--	32	463	--	--	2,281
1999	317	381	1,106	--	--	32	465	--	--	2,302
2000	314	308	1,186	--	--	33	399	--	--	2,240
2001	295	299	1,950	--	--	22	348	--	--	2,912
2002	292	301	1,216	--	--	22	357	--	--	2,188
2003	347	343	994	--	--	22	371	--	--	2,077
2004	368	321	1,069	5	--	22	404	--	--	2,188
2005	397	333	1,024	5	--	25	435	--	--	2,219
2006	428	341	1,040	5	--	25	433	--	--	2,272
2007	428	348	1,064	5	--	22	443	--	3	2,312
2008	428	352	1,059	5	--	22	444	--	3	2,312
Combined Heat and Power, Industrial[9]										
1997	4,830	1,078	11,945	1,315	--	1,102	5,376	--	552	26,198
1998	4,577	1,034	12,012	1,465	--	1,139	5,210	--	581	26,019
1999	4,443	1,062	12,877	1,689	--	1,097	5,151	--	799	27,119
2000	4,601	818	13,708	2,023	--	1,079	4,607	--	510	27,348
2001	4,156	1,124	14,123	1,327	--	1,041	4,382	--	399	26,553
2002	4,010	726	14,745	1,756	--	1,033	4,419	--	607	27,295
2003	4,127	738	15,316	1,742	--	786	4,406	--	625	27,740
2004	3,825	789	14,753	1,937	--	648	4,728	--	687	27,367
2005	3,984	777	14,501	1,757	--	662	4,747	--	802	27,230
2006	3,317	983	15,285	1,802	--	693	4,896	--	797	27,773
2007	3,194	880	14,699	1,858	--	331	5,163	--	720	26,844
2008	3,246	713	14,551	1,784	--	334	5,116	--	854	26,599

1 Anthracite, bituminous coal, subbituminous coal, lignite, and waste coal.
2 Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
3 Includes a small number of generators for which waste heat is the primary energy source.
4 Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
5 Conventional hydroelectric power excluding pumped storage facilities.
6 Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
7 Pumped storage capacity generates electricity from water pumped to an elevated reservoir and then released through a conduit to turbine generators located at a lower level.
8 Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
9 Small number of electricity-only, non-Combined Heat and Power plants may be included.
R = Revised.
Notes: • See Glossary reference for definitions. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. • Totals may not equal sum of components because of independent rounding.

Figure 1.1. U.S. Electric Industry Generating Capacity by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.1.A. Existing Net Summer Capacity of Other Renewables by Producer Type, 1997 through 2008
(Megawatts)

Period	Wind	Solar Thermal and Photovoltaic	Wood and Wood-Derived Fuels[1]	Geothermal	Other Biomass[2]	Total (Other Renewables)
Total (All Sectors)						
1997	1,610	334	6,924	2,893	3,590	15,351
1998	1,720	335	6,802	2,893	3,694	15,444
1999	2,252	389	6,795	2,846	3,660	15,942
2000	2,377	386	6,147	2,793	3,869	15,572
2001	3,864	392	5,882	2,216	3,748	16,101
2002	4,417	397	5,844	2,252	3,800	16,710
2003	5,995	397	5,871	2,133	3,758	18,153
2004	6,456	398	6,182	2,152	3,529	18,717
2005	8,706	411	6,193	2,285	3,609	21,205
2006	11,329	411	6,372	2,274	3,727	24,113
2007	16,515	502	6,704	2,214	4,134	30,069
2008	24,651	536	6,864	2,256	4,186	38,493
Electricity Generators, Electric Utilities						
1997	14	5	247	1,622	235	2,123
1998	9	5	268	1,550	236	2,067
1999	29	5	240	273	243	790
2000	54	5	259	273	247	837
2001	60	4	309	271	335	979
2002	111	9	248	271	350	989
2003	140	9	268	162	346	925
2004	326	10	313	152	160	960
2005	765	11	391	242	136	1,545
2006	1,441	11	428	240	172	2,291
2007	1,928	12	418	158	290	2,806
2008	3,190	14	427	159	276	4,066
Electricity Generators, Independent Power Producers						
1997	1,596	329	1,205	1,271	2,293	6,695
1998	1,711	330	1,170	1,344	2,400	6,955
1999	2,222	385	1,244	2,573	2,370	8,794
2000	2,323	382	1,227	2,520	2,543	8,994
2001	3,804	388	1,178	1,945	2,580	9,894
2002	4,305	388	1,162	1,981	2,553	10,390
2003	5,855	388	1,121	1,972	2,450	11,786
2004	6,130	388	1,138	2,000	2,414	12,070
2005	7,941	400	1,033	2,044	2,447	13,864
2006	9,888	400	1,037	2,034	2,505	15,865
2007	14,587	489	1,066	2,056	2,803	21,002
2008	21,461	521	1,196	2,097	2,891	28,166
Combined Heat and Power, Electric Power						
1997	--	--	325	--	382	707
1998	--	--	356	--	393	749
1999	--	--	354	--	387	741
2000	--	--	242	--	494	736
2001	--	--	144	--	354	498
2002	--	--	144	--	411	555
2003	--	--	204	--	461	665
2004	--	--	179	--	375	555
2005	--	--	218	--	395	614
2006	--	--	212	--	416	628
2007	--	--	210	--	446	656
2008	--	--	223	--	478	701
Combined Heat and Power, Commercial[3]						
1997	--	--	7	--	444	450
1998	--	--	7	--	456	463
1999	--	--	7	--	459	465
2000	--	--	7	--	392	399
2001	--	--	6	--	342	348
2002	--	--	6	--	351	357
2003	--	--	7	--	364	371
2004	--	--	7	--	397	404
2005	--	--	7	--	428	435
2006	--	--	7	--	426	433
2007	--	--	8	--	435	443
2008	--	*	8	--	436	444
Combined Heat and Power, Industrial[3]						
1997	--	--	5,141	--	236	5,376
1998	--	--	5,001	--	209	5,210
1999	--	--	4,950	--	201	5,151
2000	--	--	4,413	--	194	4,607
2001	--	--	4,245	--	138	4,382
2002	--	--	4,285	--	134	4,419
2003	--	--	4,271	--	136	4,406
2004	--	--	4,545	--	183	4,728
2005	--	--	4,545	--	202	4,747
2006	--	--	4,688	--	208	4,896
2007	--	1	5,002	--	160	5,163
2008	--	1	5,010	--	105	5,116

[1] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

[2] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[3] Small number of electricity-only, non-Combined Heat and Power plants may be included.

* = Value is less than half of the smallest unit of measure.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.2. Existing Capacity by Energy Source, 2008
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[1]	1,445	337,300	313,322	315,461
Petroleum[2]	3,768	63,655	57,445	61,538
Natural Gas[3]	5,467	454,611	397,432	427,703
Other Gases[4]	102	2,262	1,995	1,958
Nuclear	104	106,147	100,755	102,494
Hydroelectric Conventional[5]	3,996	77,731	77,930	77,694
Wind	494	24,980	24,651	24,698
Solar Thermal and Photovoltaic	89	539	536	455
Wood and Wood Derived Fuels[6]	353	7,730	6,864	6,905
Geothermal	228	3,281	2,256	2,409
Other Biomass[7]	1,412	4,854	4,186	4,263
Pumped Storage	151	20,355	21,858	21,768
Other[8]	49	1,042	942	968
Total	**17,658**	**1,104,486**	**1,010,171**	**1,048,313**

[1] Anthracite, bituminous coal, subbituminous coal, lignite, and waste coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Includes a small number of generators for which waste heat is the primary energy source.
[4] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[5] The net summer capacity and/or the net winter capacity may exceed nameplate capacity due to upgrades to and overload capability of hydroelectric generators.
[6] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[7] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.3. Existing Capacity by Producer Type, 2008
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector				
Electric Utilities	9,371	632,923	584,908	603,610
Independent Power Producers	5,344	395,594	359,044	373,888
Total	**14,715**	**1,028,517**	**943,951**	**977,497**
Combined Heat and Power Sector				
Electric Power[1]	654	42,937	37,309	40,274
Commercial[2]	639	2,593	2,312	2,407
Industrial[2]	1,650	30,439	26,599	28,134
Total	**2,943**	**75,969**	**66,219**	**70,815**
Total All Sectors	**17,658**	**1,104,486**	**1,010,171**	**1,048,313**

[1] Includes only independent power producers` combined heat and power facilities.
[2] Small number of electricity-only, non-Combined Heat and Power plants may be included.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.4. Planned Generating Capacity Additions from New Generators, by Energy Source, 2009-2013
(Count, Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
2009				
U.S. Total	**365**	**27,099**	**24,769**	**25,903**
Coal[1]	13	4,785	4,393	4,419
Petroleum[2]	16	748	695	704
Natural Gas	108	11,388	9,811	10,884
Other Gases[3]	1	78	73	73
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	7	25	24	23
Wind	107	9,459	9,205	9,205
Solar Thermal and Photovoltaic	25	145	134	140
Wood and Wood Derived Fuels[5]	4	139	129	131
Geothermal	4	64	61	61
Other Biomass[6]	80	269	245	264
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2010				
U.S. Total	**228**	**19,841**	**18,081**	**19,021**
Coal[1]	12	5,932	5,598	5,628
Petroleum[2]	13	568	515	545
Natural Gas	78	9,950	8,622	9,498
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	10	26	24	24
Wind	40	2,559	2,543	2,543
Solar Thermal and Photovoltaic	13	468	461	462
Wood and Wood Derived Fuels[5]	4	103	96	97
Geothermal	8	168	158	159
Other Biomass[6]	50	66	64	65
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2011				
U.S. Total	**103**	**13,991**	**12,549**	**13,431**
Coal[1]	6	2,837	2,481	2,521
Petroleum[2]	4	200	170	196
Natural Gas	72	8,804	7,545	8,359
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	3	7	7	6
Wind	12	1,591	1,588	1,588
Solar Thermal and Photovoltaic	2	375	593	594
Wood and Wood Derived Fuels[5]	1	61	57	57
Geothermal	--	--	--	--
Other Biomass[6]	3	117	109	110
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2012				
U.S. Total	**79**	**20,741**	**18,526**	**19,566**
Coal[1]	12	7,156	6,508	6,581
Petroleum[2]	--	--	--	--
Natural Gas	49	10,208	8,743	9,633
Other Gases[3]	2	720	619	677
Nuclear	1	1,270	1,181	1,194
Hydroelectric Conventional[4]	1	70	67	64
Wind	1	25	25	25
Solar Thermal and Photovoltaic	6	950	1,065	1,070
Wood and Wood Derived Fuels[5]	3	178	166	167
Geothermal	--	--	--	--
Other Biomass[6]	4	164	153	154
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2013				
U.S. Total	**40**	**6,294**	**5,175**	**5,602**
Coal[1]	2	630	562	592
Petroleum[2]	--	--	--	--
Natural Gas	23	5,191	4,167	4,569
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	8	245	233	226
Wind	1	16	15	15
Solar Thermal and Photovoltaic	--	--	--	--
Wood and Wood Derived Fuels[5]	1	36	34	34
Geothermal	4	156	146	147
Other Biomass[6]	1	20	19	19
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--

[1] Anthracite, bituminous coal, subbituminous coal, lignite, and waste coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Conventional hydroelectric power excluding pumped storage facilities; includes ocean power technology (wave energy).
[5] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[6] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Projected data are updated annually, so revision superscript is not used. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. These data reflect plans as of December 31, 2008. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.5. Capacity Additions, Retirements and Changes by Energy Source, 2008
(Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements				Updates and Revisions[1]		
	Number of Gene-rators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Gene-rators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[2]	5	1,651	1,482	1,493	23	802	764	764	412	-135	-213
Petroleum[3]	40	95	90	99	51	400	313	361	1,566	1,600	1,272
Natural Gas[4]	94	8,700	7,671	8,084	49	1,345	1,184	1,258	-2,133	-1,930	-1,308
Other Gases[5]	--	--	--	--	--	--	--	--	-401	-318	-334
Nuclear	--	--	--	--	--	--	--	--	383	489	729
Hydroelectric Conventional	7	18	16	16	5	22	23	16	92	53	325
Wind	101	8,304	8,090	8,105	2	1	2	2	82	48	54
Solar Thermal and Photovoltaic	47	32	31	30	--	--	--	--	4	4	4
Wood and Wood Derived Fuels[6]	3	52	47	46	--	--	--	--	168	113	114
Geothermal	4	56	31	39	--	--	--	--	-8	11	8
Other Biomass[7]	131	132	126	126	16	20	16	18	-92	-58	-60
Pumped Storage	--	--	--	--	--	--	--	--	--	-29	-31
Other[8]	1	22	20	20	1	21	20	20	174	154	154
Total	**433**	**19,062**	**17,602**	**18,058**	**147**	**2,613**	**2,321**	**2,437**	**246**	**2**	**714**

[1] Generator re-ratings, re-powering, and revisions/corrections to previously reported data.
[2] Anthracite, bituminous coal, subbituminous coal, lignite, and waste coal.
[3] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[4] Includes a small number of generators for which waste heat is the primary energy source.
[5] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[6] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[7] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.6.A. Capacity of Dispersed Generators by Technology Type, 2004 through 2008
(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Total	
						Number of Generators	(MW)
2004.............................	3,366[R]	210	552	26	2	11,123	4,156
2005.............................	4,290[R]	335[R]	126	2	13	11,373	4,766
2006.............................	6,524[R]	346[R]	157[R]	3[R]	8	9,536	7,037
2007.............................	7,866[R]	268[R]	102[R]	31	30[R]	11,057	8,297
2008.............................	9,335	86	248	34	70	12,262	9,773

R = Revised.
Note: Dispersed generators are commercial and industrial generators which are not connected to the grid. They may be installed at or near a customer`s site, or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 1.6.B. Capacity of Distributed Generators by Technology Type, 2004 through 2008
(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Total	
						Number of Generators	(MW)
2004.............................	2,168[R]	1,028	1,085[R]	1,004[R]	138[R]	5,863	5,423
2005[1]	4,025[R]	1,917	1,830[R]	999[R]	995[R]	17,371	9,766
2006.............................	3,646[R]	1,298[R]	2,582[R]	806	1,081[R]	5,044	9,411[R]
2007.............................	4,624[R]	1,990[R]	3,596[R]	1,051[R]	1,441[R]	7,103	12,702
2008.............................	5,112	1,949	3,060	1,154	1,588	9,591	12,863

[1] Distributed generator data in 2005 include a significant number of generators reported by one respondent, which may be for residential applications.
R = Revised.
Note: Distributed generators are commercial and industrial generators which are connected to the grid. They may be installed at or near a customer`s site, or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 1.6.C. Total Capacity of Dispersed and Distributed Generators by Technology Type, 2004 through 2008
(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Total	
						Number of Generators	(MW)
2004.............................	5,534[R]	1,238	1,637[R]	1,030[R]	140[R]	16,986	9,579
2005[1]	8,315[R]	2,252[R]	1,956[R]	1,001[R]	1,008[R]	28,744	14,532
2006.............................	10,169[R]	1,644[R]	2,739[R]	809[R]	1,088[R]	14,580	16,448[R]
2007.............................	12,490[R]	2,258[R]	3,698[R]	1,082[R]	1,471[R]	18,160	20,999
2008.............................	14,447	2,035	3,308	1,188	1,658	21,853	22,636

[1] Distributed generator data in 2005 include a significant number of generators reported by one respondent, which may be for residential applications.
R = Revised.
Note: Dispersed and distributed generators are commercial and industrial generators. Dispersed generators are not connected to the grid. Distributed generators are connected to the grid. Both types of generators may be installed at or near a customer`s site, or at other locations, and both types of generators may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 1.7. Fuel Switching Capacity of Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2008
(Megawatts, Percent)

Producer Type	Total Net Summer Capacity of All Generators Reporting Natural Gas as the Primary Fuel	Fuel-Switchable Part of Total			
		Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids[1]	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Electric Utility	173,106	71,884	41.5	71,364	25,734
Independent Power Producers	179,141	40,121	22.4	39,050	11,320
Combined Heat and Power, Electric Power[2]	29,575	6,142	20.8	5,960	617
Electric Power Sector Subtotal	**381,822**	**118,147**	**30.9**	**116,374**	**37,671**
Combined Heat and Power, Commercial[3]	1,059	484	45.6	481	89
Combined Heat and Power, Industrial[3]	14,551	1,268	8.7	1,208	260
All Sectors	**397,432**	**119,899**	**30.2**	**118,063**	**38,020**

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
[2] Electric Utility CHP plants are included in Electric Utilities.
[3] Small number of electricity-only, non-Combined Heat and Power plants may be included.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.8. Fuel Switching Capacity of Generators Reporting Petroleum Liquids as the Primary Fuel, by Producer Type, 2008
(Megawatts, Percent)

Producer Type	Total Net Summer Capacity of All Generators Reporting Petroleum as the Primary Fuel[1]	Fuel-Switchable Part of Total		
		Net Summer Capacity of Petroleum-Fired Generators Reporting the Ability to Switch to Natural Gas	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Natural Gas
Electric Utility	30,657	10,797	35.2	10,411
Independent Power Producers	24,823	12,261	49.4	10,372
Combined Heat and Power Electric Power[2]	900	445	49.4	195
Electric Power Sector Subtotal	**56,379**	**23,503**	**41.7**	**20,978**
Combined Heat and Power Commercial[3]	352	29	8.2	28
Combined Heat and Power Industrial[3]	713	88	12.3	62
All Sectors	**57,445**	**23,620**	**41.1**	**21,068**

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
[2] Electric Utility CHP plants are included in Electric Utilities.
[3] Small number of electricity-only, non-Combined Heat and Power plants may be included.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.9. Fuel-Switching Capacity: From Natural Gas to Petroleum Liquids, by Type of Prime Mover, 2008
(Count, Megawatts)

Prime Mover Type	Number of Generators	Net Summer Capacity	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids[1]
Steam Generator	208	28,766	16,777
Combined Cycle	383	36,339	5,722
Internal Combustion	336	935	354
Gas Turbine	929	53,859	15,167
All Fuel Switchable Prime Movers	1,856	119,899	38,020

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.10. Fuel-Switching Capacity: From Natural Gas to Petroleum Liquids, by Year of Initial Commercial Operation, 2008
(Count, Megawatts)

Year of Initial Commercial Operation	Number of Generators	Net Summer Capacity	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids[1]
pre-1970	389	15,847	9,596
1970-1974	391	18,264	9,759
1975-1979	105	9,977	5,605
1980-1984	47	961	230
1985-1989	115	3,356	490
1990-1994	212	12,955	2,150
1995-1999	137	10,103	2,262
2000-2004	384	39,484	6,427
2005-2008	76	8,953	1,502
Total	1,856	119,899	38,020

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.11. Interconnection Cost and Capacity for New Generators, by Producer Type, 2007 and 2008

Sector	Units[1]	Nameplate Capacity (megawatts)[1]	Cost (thousand dollars)[1]
2007			
Total	269	14,061	397,921
Electric Utilities[2]	97	8,527	184,813
Independent Power Producers[3]	162	5,413	208,733
Commercial[4]	6	10	421
Industrial[4,R]	4	111	3,954
2008			
Total	356	16,947	523,846
Electric Utilities[2]	108	8,479	185,955
Independent Power Producers[3]	243	8,456	337,145
Commercial[4]	4	10	745
Industrial[4]	1	3	1

[1] Cost is the total cost incurred for the direct, physical interconnection of generators that started commercial operation in the respective years. These generator-specific costs may include costs for transmission or distribution lines, transformers, protective devices, substations, switching stations and other equipment necessary for interconnection. Units and Nameplate Capacity represent the number of units and associated capacity for which interconnection costs were incurred and reported.
[2] Electric utility CHP plants are included in Electric Generators, Electric Utilities.
[3] Includes only independent power producers` combined heat and power facilities.
[4] Small number of electricity-only, non-Combined Heat and Power plants may be included.
R = Revised.
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.12. Interconnection Cost and Capacity for New Generators, by Grid Voltage Class, 2007 and 2008

Voltage Class	Units[1]	Nameplate Capacity (megawatts)[1]	Cost (thousand dollars)[1]
2007			
Total	269	14,061	397,921
Distribution (< 35 kV)[R]	104	556	20,462
SubTransmission (35 kV - 138 kV)[R]	103	3,773	131,840
Transmission (> 138 kV)	62	9,731	245,619
2008			
Total	356	16,947	523,846
Distribution (< 35 kV)	101	497	25,198
SubTransmission (35 kV - 138 kV)	178	6,677	181,061
Transmission (> 138 kV)	77	9,773	317,587

[1] Cost is the total cost incurred for the direct, physical interconnection of generators that started commercial operation in the respective years. These generator-specific costs may include costs for transmission or distribution lines, transformers, protective devices, substations, switching stations and other equipment necessary for interconnection. Units and Nameplate Capacity represent the number of units and associated capacity for which interconnection costs were incurred and reported.

R = Revised.

kV=Kilovolt=1000 volts.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

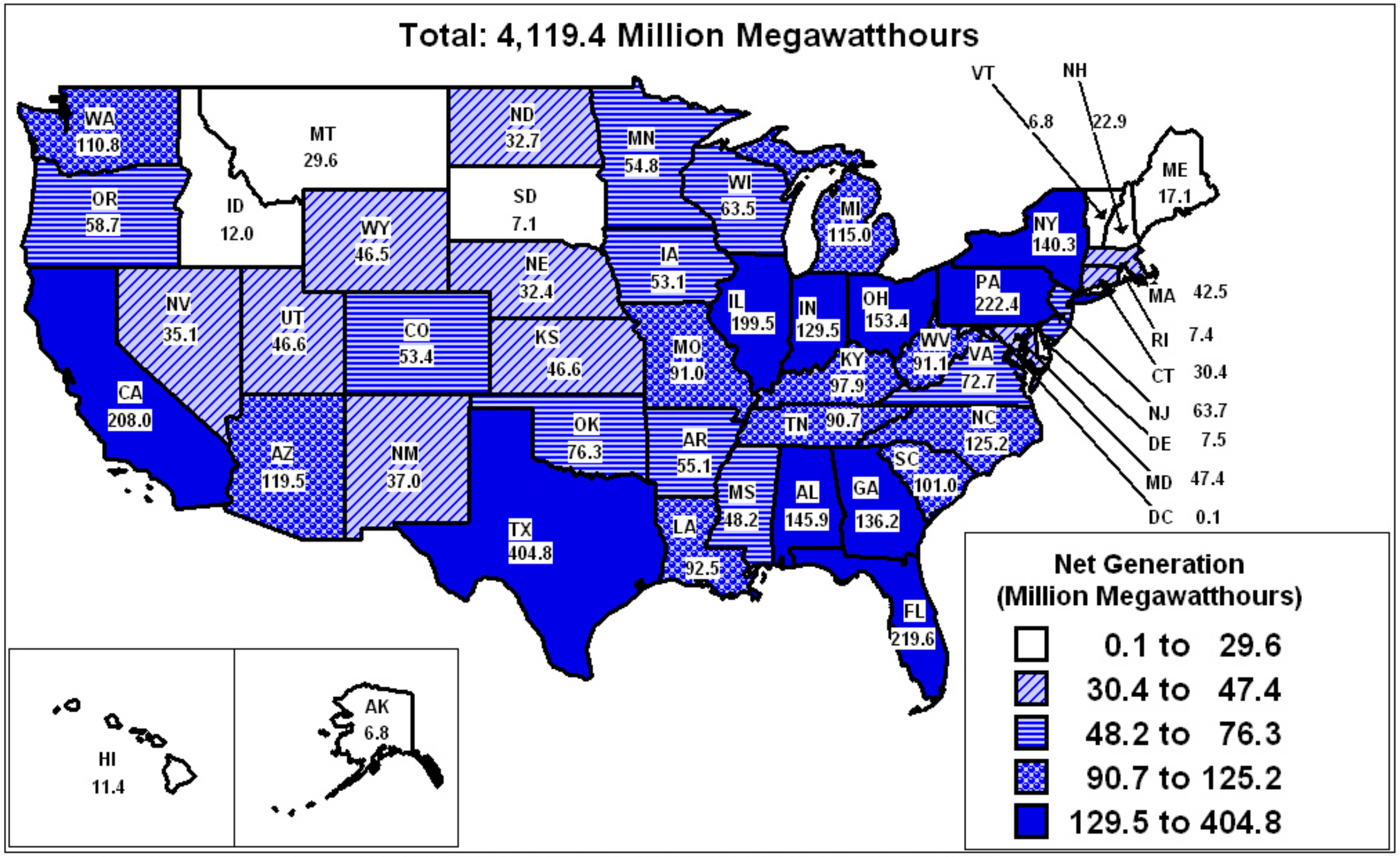
Chapter 2. Generation and Useful Thermal Output

Table 2.1. Net Generation by Energy Source by Type of Producer, 1997 through 2008
(Thousand Megawatthours)

Period	Coal[1]	Petroleum [2]	Natural Gas	Other Gases[3]	Nuclear	Hydroelectric Conventional[4]	Other Renewables[5]	Hydroelectric Pumped Storage[6]	Other[7]	Total
Total (All Sectors)										
1997	1,845,016	92,555	479,399	13,351	628,644	356,453	77,183	-4,040	3,612	3,492,172
1998	1,873,516	128,800	531,257	13,492	673,702	323,336	77,088	-4,467	3,571	3,620,295
1999	1,881,087	118,061	556,396	14,126	728,254	319,536	79,423	-6,097	4,024	3,694,810
2000	1,966,265	111,221	601,038	13,955	753,893	275,573	80,906	-5,539	4,794	3,802,105
2001	1,903,956	124,880	639,129	9,039	768,826	216,961	70,769	-8,823	11,906	3,736,644
2002	1,933,130	94,567	691,006	11,463	780,064	264,329	79,109	-8,743	13,527	3,858,452
2003	1,973,737	119,406	649,908	15,600	763,733	275,806	79,487	-8,535	14,045	3,883,185
2004	1,978,301	121,145	710,100	15,252	788,528	268,417	83,067	-8,488	14,232	3,970,555
2005	2,012,873	122,225	760,960	13,464	781,986	270,321	87,329	-6,558	12,821	4,055,423
2006	1,990,511	64,166	816,441	14,177	787,219	289,246	96,525	-6,558	12,974	4,064,702
2007	2,016,456	65,739	896,590	13,453	806,425	247,510	105,238	-6,896	12,231	4,156,745
2008	1,985,801	46,243	882,981	11,707	806,208	254,831	126,212	-6,288	11,692	4,119,388
Electricity Generators, Electric Utilities										
1997	1,787,806	77,753	283,625	--	628,644	341,273	7,462	-4,040	--	3,122,523
1998	1,807,480	110,158	309,222	--	673,702	308,844	7,206	-4,441	--	3,212,171
1999	1,767,679	86,929	296,381	--	725,036	299,914	3,716	-5,982	--	3,173,674
2000	1,696,619	72,180	290,715	--	705,433	253,155	2,241	-4,960	--	3,015,383
2001	1,560,146	78,908	264,434	--	534,207	197,804	1,666	-7,704	486	2,629,946
2002	1,514,670	59,125	229,639	206	507,380	242,302	3,089	-7,434	480	2,549,457
2003	1,500,281	69,930	186,967	243	458,829	249,622	3,421	-7,532	519	2,462,281
2004	1,513,641	73,694	199,662	374	475,682	245,546	3,692	-7,526	467	2,505,231
2005	1,484,855	69,722	238,204	10	436,296	245,553	4,945	-5,383	643	2,474,846
2006	1,471,421	40,903	282,088	30	425,341	261,864	6,588	-5,281	700	2,483,656
2007	1,490,985	40,719	313,785	141	427,555	226,734	8,953	-5,328	586	2,504,131
2008	1,466,395	28,124	320,190	46	424,256	229,645	11,308	-5,143	545	2,475,367
Electricity Generators, Independent Power Producers										
1997	5,344	2,557	7,506	31	--	9,375	33,929	--	--	58,741
1998	15,539	5,503	26,657	55	--	9,023	34,703	-26	--	91,455
1999	64,387	17,906	60,264	36	3,218	14,749	40,460	-115	--	200,905
2000	213,956	25,795	108,712	181	48,460	18,183	42,831	-579	--	457,540
2001	291,678	34,257	162,540	10	234,619	15,945	37,200	-1,119	5,460	780,592
2002	366,535	24,150	227,155	29	272,684	18,189	40,729	-1,309	7,168	955,331
2003	415,498	38,571	234,240	13	304,904	21,890	42,058	-1,003	7,035	1,063,205
2004	407,418	35,665	291,527	7	312,846	19,518	45,743	-962	7,108	1,118,870
2005	470,658	41,485	314,970	3	345,690	21,477	48,294	-1,174	5,569	1,246,971
2006	462,302	14,340	335,898	3	361,877	24,383	55,890	-1,277	5,646	1,259,062
2007	470,978	16,189	372,523	3	378,869	19,103	62,301	-1,569	5,458	1,323,856
2008	465,558	11,145	363,138	1	381,952	23,444	82,470	-1,145	5,505	1,332,068
Combined Heat and Power, Electric Power[8]										
1997	27,611	6,170	108,465	1,503	--	--	4,299	--	63	148,111
1998	27,174	6,550	113,413	2,260	--	--	4,234	--	159	153,790
1999	26,551	6,704	116,351	1,571	--	--	4,088	--	139	155,404
2000	32,536	7,217	118,551	1,847	--	--	4,330	--	125	164,606
2001	31,003	5,984	127,966	576	--	--	3,393	--	595	169,515
2002	29,408	6,458	150,889	1,734	--	--	3,737	--	1,444	193,670
2003	36,935	5,195	146,097	2,392	--	--	4,002	--	1,053	195,674
2004	36,128	5,320	135,983	3,187	--	--	2,893	--	747	184,259
2005	36,541	5,275	130,655	3,765	--	10	3,415	--	716	180,375
2006	36,014	4,465	116,430	4,220	--	8	3,456	--	766	165,359
2007	36,428	4,398	128,444	3,898	--	6	3,450	--	733	177,356
2008	36,884	3,612	119,043	3,153	--	6	3,417	--	798	166,915
Combined Heat and Power, Commercial[9]										
1997	1,040	427	4,725	3	--	120	2,385	--	*	8,701
1998	985	383	4,879	7	--	120	2,373	--	--	8,748
1999	995	434	4,607	*	--	115	2,412	--	*	8,563
2000	1,097	432	4,262	*	--	100	2,012	--	*	7,903
2001	995	438	4,434	*	--	66	1,025	--	457	7,416
2002	992	431	4,310	*	--	13	1,065	--	603	7,415
2003	1,206	423	3,899	--	--	72	1,302	--	594	7,496
2004	1,340	499	3,969	--	--	105	1,575	--	781	8,270
2005	1,353	375	4,249	--	--	86	1,673	--	756	8,492
2006	1,310	235	4,355	*	--	93	1,619	--	758	8,371
2007	1,371	189	4,257	--	--	77	1,614	--	764	8,273
2008	1,261	142	4,188	--	--	60	1,555	--	720	7,926
Combined Heat and Power, Industrial[9]										
1997	23,214	5,649	75,078	11,814	--	5,685	29,107	--	3,549	154,097
1998	22,337	6,206	77,085	11,170	--	5,349	28,572	--	3,412	154,132
1999	21,474	6,088	78,793	12,519	--	4,758	28,747	--	3,885	156,264
2000	22,056	5,597	78,798	11,927	--	4,135	29,491	--	4,669	156,673
2001	20,135	5,293	79,755	8,454	--	3,145	27,485	--	4,908	149,175
2002	21,525	4,403	79,013	9,493	--	3,825	30,489	--	3,832	152,580
2003	19,817	5,285	78,705	12,953	--	4,222	28,704	--	4,843	154,530
2004	19,773	5,967	78,959	11,684	--	3,248	29,164	--	5,129	153,925
2005	19,466	5,368	72,882	9,687	--	3,195	29,003	--	5,137	144,739
2006	19,464	4,223	77,669	9,923	--	2,899	28,972	--	5,103	148,254
2007	16,694	4,243	77,580	9,411	--	1,590	28,919	--	4,690	143,128
2008	15,703	3,219	76,421	8,507	--	1,676	27,462	--	4,125	137,113

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Conventional hydroelectric power excluding pumped storage facilities.
[5] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.
[6] The quantity of output from a hydroelectric pumped storage facility represents production minus energy used for pumping.
[7] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[8] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[9] Small number of electricity-only, non-Combined Heat and Power plants may be included.
* = Value is less than half of the smallest unit of measure.
Note: Totals may not equal sum of components because of independent rounding
Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Figure 2.1. U.S. Electric Industry Net Generation by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" .

Table 2.1.A. Net Generation by Selected Renewables by Type of Producer, 1997 through 2008
(Thousand Megawatthours)

Period	Wind	Solar Thermal and Photovoltaic	Wood and Wood-Derived Fuels[1]	Geothermal	Other Biomass[2]	Total (Other Renewables)
Total (All Sectors)						
1997	3,288	511	36,948	14,726	21,709	77,183
1998	3,026	502	36,338	14,774	22,448	77,088
1999	4,488	495	37,041	14,827	22,572	79,423
2000	5,593	493	37,595	14,093	23,131	80,906
2001	6,737	543	35,200	13,741	14,548	70,769
2002	10,354	555	38,665	14,491	15,044	79,109
2003	11,187	534	37,529	14,424	15,812	79,487
2004	14,144	575	38,117	14,811	15,421	83,067
2005	17,811	550	38,856	14,692	15,420	87,329
2006	26,589	508	38,762	14,568	16,099	96,525
2007	34,450	612	39,014	14,637	16,525	105,238
2008	55,363	864	37,300	14,951	17,734	126,212
Electricity Generators, Electric Utilities						
1997	6	3	739	5,469	1,244	7,462
1998	3	3	719	5,176	1,305	7,206
1999	23	3	684	1,698	1,307	3,716
2000	29	3	700	151	1,358	2,241
2001	135	3	560	152	815	1,666
2002	213	3	709	1,402	761	3,089
2003	354	2	882	1,249	934	3,421
2004	405	6	1,209	1,248	824	3,692
2005	1,046	16	1,829	1,126	929	4,945
2006	2,351	15	1,937	1,162	1,123	6,588
2007	4,361	11	2,226	1,139	1,217	8,953
2008	6,899	17	1,888	1,197	1,307	11,308
Electricity Generators, Independent Power Producers						
1997	3,282	508	5,729	9,257	15,153	33,929
1998	3,023	500	5,925	9,598	15,658	34,703
1999	4,465	492	6,569	13,129	15,805	40,460
2000	5,565	491	6,601	13,942	16,234	42,831
2001	6,602	539	6,011	13,588	10,460	37,200
2002	10,141	552	6,556	13,089	10,391	40,729
2003	10,834	532	6,520	13,175	10,998	42,058
2004	13,739	569	6,940	13,563	10,932	45,743
2005	16,764	535	6,668	13,566	10,761	48,294
2006	24,238	493	6,374	13,406	11,379	55,890
2007	30,089	601	6,451	13,498	11,662	62,301
2008	48,464	847	6,746	13,754	12,659	82,470
Combined Heat and Power, Electric Power[3]						
1997	--	--	2,212	--	2,087	4,299
1998	--	--	1,964	--	2,270	4,234
1999	--	--	1,707	--	2,381	4,088
2000	--	--	1,615	--	2,715	4,330
2001	--	--	1,723	--	1,669	3,393
2002	--	--	1,744	--	1,993	3,737
2003	--	--	2,126	--	1,876	4,002
2004	--	--	1,588	--	1,306	2,893
2005	--	--	2,073	--	1,341	3,415
2006	--	--	2,030	--	1,426	3,456
2007	--	--	2,034	--	1,416	3,450
2008	--	--	2,004	--	1,413	3,417
Combined Heat and Power, Commercial[4]						
1997	--	--	43	--	2,342	2,385
1998	--	--	38	--	2,335	2,373
1999	--	--	20	--	2,393	2,412
2000	--	--	27	--	1,985	2,012
2001	--	--	18	--	1,007	1,025
2002	--	--	13	--	1,053	1,065
2003	--	--	13	--	1,289	1,302
2004	--	--	13	--	1,562	1,575
2005	--	--	16	--	1,657	1,673
2006	--	--	21	--	1,599	1,619
2007	--	--	15	--	1,599	1,614
2008	--	*	21	--	1,534	1,555
Combined Heat and Power, Industrial[4]						
1997	--	--	28,225	--	882	29,107
1998	--	--	27,693	--	880	28,572
1999	--	--	28,060	--	686	28,747
2000	--	--	28,652	--	839	29,491
2001	--	--	26,888	--	596	27,485
2002	--	--	29,643	--	846	30,489
2003	--	--	27,988	--	715	28,704
2004	--	--	28,367	--	797	29,164
2005	--	--	28,271	--	733	29,003
2006	--	--	28,400	--	572	28,972
2007	--	--	28,287	--	631	28,919
2008	--	--	26,641	--	821	27,462

[1] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[2] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[3] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[4] Small number of electricity-only, non-Combined Heat and Power plants may be included.
* = Value is less than half of the smallest unit of measure.
Note: Totals may not equal sum of components because of independent rounding
Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Table 2.2. Useful Thermal Output by Energy Source by Combined Heat and Power Producers, 1997 through 2008
(Billion Btus)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Other Renewables[4]	Other[5]	Total
Total Combined Heat and Power							
1997	388,944	136,742	712,683	150,144	785,306	53,361	2,227,180
1998	381,546	135,519	781,637	167,064	757,131	46,437	2,269,334
1999	385,926	125,486	810,918	178,971	744,470	47,871	2,293,642
2000	383,687	108,045	812,036	184,062	763,674	50,459	2,301,963
2001	354,204	90,308	740,979	132,937	584,560	55,162	1,958,151
2002	336,848	72,826	708,738	117,513	571,507	48,264	1,855,697
2003	333,361	85,263	610,122	110,263	632,368	54,960	1,826,335
2004	351,871	97,484	654,242	126,157	667,341	45,456	1,942,550
2005	341,806	92,383	624,008	138,469	664,691	41,400	1,902,757
2006	332,548	78,232	603,288	126,049	689,549	49,308	1,878,973
2007	326,803	76,255	554,394	116,313	651,230	46,822	1,771,816
2008	315,244	47,817	509,330	110,680	610,131	23,729	1,616,931
Combined Heat and Power, Electric Power							
1997	39,437	11,823	132,125	7,746	30,147	29	221,307
1998	43,256	6,261	141,834	5,064	25,969	68	222,452
1999	52,061	6,718	145,525	3,548	30,172	28	238,052
2000	53,329	6,610	157,886	5,312	25,661	39	248,837
2001	51,515	6,087	164,206	4,681	12,676	3,343	242,508
2002	40,020	3,869	214,137	5,961	12,550	4,732	281,269
2003	38,249	7,379	200,077	9,282	19,786	3,296	278,068
2004	39,014	8,217	239,416	18,200	17,347	3,822	326,017
2005	39,652	7,809	239,324	36,694	18,240	3,884	345,605
2006	38,133	7,065	207,095	22,567	17,284	4,435	296,579
2007	38,260	7,156	212,705	20,473	19,166	4,459	302,219
2008	37,220	6,832	204,167	22,109	17,052	4,854	292,234
Combined Heat and Power, Commercial							
1997	21,958	3,832	39,893	20	20,232	--	85,935
1998	20,185	4,853	38,510	34	18,426	--	82,008
1999	20,479	3,298	36,857	--	17,145	--	77,779
2000	21,001	3,827	39,293	--	17,613	--	81,734
2001	18,495	4,118	34,923	--	8,253	5,770	71,560
2002	18,477	2,743	36,265	--	6,901	4,801	69,188
2003	22,780	2,716	16,955	--	8,297	6,142	56,889
2004	22,450	4,283	21,851	--	8,936	6,350	63,871
2005	22,601	3,684	20,227	--	8,647	5,921	61,081
2006	22,186	2,264	19,370	0	9,359	6,242	59,422
2007	22,595	1,861	20,040	--	6,651	3,983	55,131
2008	22,991	1,999	20,183	--	8,863	6,054	60,091
Combined Heat and Power, Industrial							
1997	327,549	121,087	540,665	142,378	734,927	53,332	1,919,938
1998	318,105	124,405	601,293	161,966	712,736	46,369	1,964,874
1999	313,386	115,470	628,536	175,423	697,153	47,843	1,977,811
2000	309,357	97,608	614,857	178,750	720,400	50,420	1,971,392
2001	284,194	80,103	541,850	128,256	563,631	46,049	1,644,083
2002	278,351	66,214	458,336	111,552	552,056	38,731	1,505,240
2003	272,332	75,168	393,090	100,981	604,285	45,522	1,491,378
2004	290,407	84,984	392,974	107,956	641,058	35,284	1,552,663
2005	279,552	80,889	364,457	101,775	637,803	31,594	1,496,071
2006	272,229	68,903	376,822	103,481	662,906	38,630	1,522,971
2007	265,948	67,238	321,648	95,840	625,413	38,380	1,414,466
2008	255,032	38,986	284,980	88,571	584,216	12,821	1,264,606

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology) and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.
[5] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • The methodology to allocate fuel use by combined heat and power plants to electric power generation and useful thermal output was modified beginning in 2007, and retroactively applied to data from 2004 to 2006. For more information, please see the Technical Notes in the Appendices. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Chapter 3. Fuel and Emissions

Table 3.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1997 through 2008

Type of Power Producer and Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1997	931,949	159,715	4,564,770	119,412
1998	946,295	222,640	5,081,384	124,988
1999	949,802	207,871	5,321,984	126,387
2000	994,933	195,228	5,691,481	125,971
2001	972,691	216,672	5,832,305	97,308
2002	987,583	168,597	6,126,062	131,230
2003	1,014,058	206,653	5,616,135	156,306
2004	1,020,523	203,494	5,674,580	135,144
2005	1,041,448	206,785	6,036,370	109,916
2006	1,030,556	110,634	6,461,615	114,665
2007	1,046,795	112,615	7,089,342	114,904
2008	1,042,335	80,932	6,895,843	96,757
Electricity Generators, Electric Utilities				
1997	900,361	132,147	2,968,453	--
1998	910,867	187,461	3,258,054	--
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	5,182
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,541	1,809,443	5,163
2005	761,349	118,874	2,134,859	91
2006	753,390	71,624	2,478,396	358
2007	764,765	70,950	2,736,418	1,523
2008	760,326	50,475	2,730,134	1,818
Electricity Generators, Independent Power Producers				
1997	3,884	4,010	70,774	642
1998	9,486	9,676	285,878	1,345
1999	30,572	30,037	615,756	696
2000	107,745	45,011	1,049,636	1,951
2001	139,799	60,489	1,477,643	92
2002	192,274	44,993	1,998,782	354
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,092	86
2005	254,291	72,953	2,457,412	43
2006	251,379	26,873	2,612,653	49
2007	258,075	29,868	2,875,183	62
2008	257,480	21,284	2,790,358	19
Combined Heat and Power, Electric Power[4]				
1997	14,764	11,046	863,968	13,773
1998	13,773	12,310	871,881	21,406
1999	13,197	12,440	914,600	13,627
2000	15,634	13,147	921,341	16,871
2001	15,455	11,175	978,563	9,352
2002	15,174	11,942	1,149,812	19,958
2003	19,498	8,431	1,128,935	23,317
2004	17,685	8,209	933,804	21,899
2005	17,927	7,933	892,509	24,289
2006	18,033	6,738	800,173	27,173
2007	18,506	6,498	890,012	25,428
2008	19,085	5,389	821,839	21,513
Combined Heat and Power, Commercial[5]				
1997	630	790	38,975	23
1998	440	802	40,693	54
1999	481	931	39,045	*
2000	514	823	37,029	*
2001	532	1,023	36,248	*
2002	477	834	32,545	*
2003	582	894	38,480	--
2004	377	766	32,839	--
2005	377	585	33,785	--
2006	347	333	34,623	--
2007	361	258	34,087	--
2008	369	166	33,403	--
Combined Heat and Power, Industrial[5]				
1997	12,311	11,723	622,599	104,974
1998	11,728	12,392	624,878	102,183
1999	11,432	12,595	639,165	112,064
2000	11,706	10,459	640,381	107,149
2001	10,636	10,530	653,565	87,864
2002	11,855	11,608	685,239	105,737
2003	10,440	10,424	668,407	126,739
2004	7,687	6,919	566,401	107,995
2005	7,504	6,440	517,805	85,492
2006	7,408	5,066	535,770	87,084
2007	5,089	5,041	553,643	87,892
2008	5,075	3,617	520,109	73,407

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[5] Small number of electricity-only, non-Combined Heat and Power plants may be included.
* = Value is less than half of the smallest unit of measure.
Notes: • See Glossary reference for definitions • A new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented with publication of the preliminary 2008 data, and retroactively applied to 2004-2007 data. The new methodology evenly distributes a combined heat and power (CHP) plant`s losses between

the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change results in the fuel for electric power to be lower while the fuel for UTO is higher than the prior set of data as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power after 2003.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Table 3.2. Consumption of Fossil Fuels for Useful Thermal Output by Type of Combined Heat and Power Producers, 1997 through 2008

Type of Power Producer and Year	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total Combined Heat and Power				
1997	21,005	28,802	868,569	187,680
1998	20,320	28,845	949,106	208,828
1999	20,373	26,822	982,958	223,713
2000	20,466	22,266	985,263	230,082
2001	18,944	18,268	898,286	166,161
2002	17,561	14,811	860,019	146,882
2003	17,720	17,939	721,267	137,837
2004	24,275	25,870	1,052,100	218,295
2005	23,833	24,408	984,340	238,396
2006	23,227	20,371	942,817	226,464
2007	22,810	19,775	872,579	214,321
2008	22,168	12,016	793,537	203,236
Electric Power[4]				
1997	2,355	2,466	161,608	9,684
1998	2,493	1,322	172,471	6,329
1999	3,033	1,423	175,757	4,435
2000	3,107	1,412	192,253	6,641
2001	2,910	1,171	199,808	5,849
2002	2,255	841	263,619	7,448
2003	2,080	1,596	225,967	11,601
2004	3,809	2,688	388,424	31,132
2005	3,918	2,424	384,365	59,569
2006	3,834	2,129	330,878	36,963
2007	3,795	2,114	339,796	34,384
2008	3,689	1,907	326,048	37,899
Commercial				
1997	1,108	794	47,941	25
1998	1,002	1,006	46,527	41
1999	1,009	682	44,991	--
2000	1,034	792	47,844	--
2001	916	809	42,407	--
2002	929	416	41,430	--
2003	1,234	555	19,973	--
2004	1,540	1,243	39,233	--
2005	1,544	1,045	34,172	--
2006	1,539	601	33,112	1
2007	1,566	494	35,987	--
2008	1,652	504	32,813	--
Industrial				
1997	17,542	25,541	659,021	177,971
1998	16,824	26,518	730,108	202,458
1999	16,330	24,718	762,210	219,278
2000	16,325	20,062	745,165	223,441
2001	15,119	16,287	656,071	160,312
2002	14,377	13,555	554,970	139,434
2003	14,406	15,788	475,327	126,236
2004	18,926	21,939	624,443	187,162
2005	18,371	20,940	565,803	178,827
2006	17,854	17,640	578,828	189,501
2007	17,449	17,166	496,796	179,937
2008	16,827	9,605	434,676	165,337

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Electric utility CHP plants are included in Table 4.1 with Electric Generators, Electric Utilities.

Notes: • Totals may not equal sum of components because of independent rounding. • A new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented with publication of the preliminary 2008 data, and retroactively applied to 2004-2007 data. The new methodology evenly distributes a combined heat and power (CHP) plant`s losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change results in the fuel for electric power to be lower while the fuel for UTO is higher than the prior set of data as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power after 2003.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Table 3.3. Consumption of Fossil Fuels for Electricity Generation and for Useful Thermal Output, 1997 through 2008

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1997	952,955	188,517	5,433,338	307,092
1998	966,615	251,486	6,030,490	333,816
1999	970,175	234,694	6,304,942	350,100
2000	1,015,398	217,494	6,676,744	356,053
2001	991,635	234,940	6,730,591	263,469
2002	1,005,144	183,408	6,986,081	278,111
2003	1,031,778	224,593	6,337,402	294,143
2004	1,044,798	229,364	6,726,679	353,438
2005	1,065,281	231,193	7,020,709	348,312
2006	1,053,783	131,005	7,404,432	341,129
2007	1,069,606	132,389	7,961,922	329,225
2008	1,064,503	92,948	7,689,380	299,993
Electricity Generators, Electric Utilities				
1997	900,361	132,147	2,968,453	--
1998	910,867	187,461	3,258,054	--
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	5,182
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,541	1,809,443	5,163
2005	761,349	118,874	2,134,859	91
2006	753,390	71,624	2,478,396	358
2007	764,765	70,950	2,736,418	1,523
2008	760,326	50,475	2,730,134	1,818
Electricity Generators, Independent Power Producers				
1997	3,884	4,010	70,774	642
1998	9,486	9,676	285,878	1,345
1999	30,572	30,037	615,756	696
2000	107,745	45,011	1,049,636	1,951
2001	139,799	60,489	1,477,643	92
2002	192,274	44,993	1,998,782	354
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,092	86
2005	254,291	72,953	2,457,412	43
2006	251,379	26,873	2,612,653	49
2007	258,075	29,868	2,875,183	62
2008	257,480	21,284	2,790,358	19
Combined Heat and Power, Electric Power[4]				
1997	17,118	13,512	1,025,575	23,457
1998	16,266	13,632	1,044,352	27,735
1999	16,230	13,864	1,090,356	18,062
2000	18,741	14,559	1,113,595	23,512
2001	18,365	12,346	1,178,371	15,201
2002	17,430	12,783	1,413,431	27,406
2003	21,578	10,028	1,354,901	34,918
2004	21,494	10,897	1,322,228	53,031
2005	21,845	10,357	1,276,874	83,858
2006	21,867	8,867	1,131,051	64,136
2007	22,301	8,613	1,229,808	59,812
2008	22,774	7,296	1,147,887	59,412
Combined Heat and Power, Commercial[5]				
1997	1,738	1,584	86,915	48
1998	1,443	1,807	87,220	95
1999	1,490	1,613	84,037	*
2000	1,547	1,615	84,874	*
2001	1,448	1,832	78,655	*
2002	1,405	1,250	73,975	*
2003	1,816	1,449	58,453	--
2004	1,917	2,009	72,072	--
2005	1,922	1,630	67,957	--
2006	1,886	935	67,735	1
2007	1,927	752	70,074	--
2008	2,021	671	66,216	--
Combined Heat and Power, Industrial[5]				
1997	29,853	37,265	1,281,620	282,945
1998	28,553	38,910	1,354,986	304,641
1999	27,763	37,312	1,401,374	331,342
2000	28,031	30,520	1,385,546	330,590
2001	25,755	26,817	1,309,636	248,176
2002	26,232	25,163	1,240,209	245,171
2003	24,846	26,212	1,143,734	252,975
2004	26,613	28,857	1,190,844	295,158
2005	25,875	27,380	1,083,607	264,319
2006	25,262	22,706	1,114,597	276,585
2007	22,537	22,207	1,050,439	267,829
2008	21,902	13,222	954,785	238,744

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[5] Small number of electricity-only, non-Combined Heat and Power plants may be included.
* = Value is less than half of the smallest unit of measure.
Note: Totals may not equal sum of components because of independent rounding

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Table 3.4. End-of-Year Stocks of Coal and Petroleum by Type of Producer, 1997 through 2008

Period	Electric Power Sector		Electric Utilities		Independent Power Producers	
	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Coal (Thousand Tons)	Petroleum (Thousand Barrels)
1997	98,826	51,138	98,826	51,138	NA	NA
1998	120,501	56,591	120,501	56,591	NA	NA
1999	141,604	54,109	129,041	46,169	12,563	7,940
2000	102,296	40,932	90,115	30,502	12,180	10,430
2001	138,496	57,031	117,147	37,308	21,349	19,723
2002	141,714	52,490	116,952	31,243	24,761	21,247
2003	121,567	53,170	97,831	29,953	23,736	23,218
2004	106,669	51,434	84,917	32,281	21,751	19,153
2005	101,137	50,062	77,457	31,400	23,680	18,661
2006	140,964	51,583	110,277	32,082	30,688	19,502
2007	151,221	47,203	120,504	29,297	30,717	17,906
2008	161,589	44,498	127,463	28,450	34,126	16,048

[1] Anthracite, bituminous, subbituminous, lignite, and synthetic coal, excludes waste coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology). Data prior to 2005 includes small quantities of waste oil.
NA = Not available.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Table 3.5. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1997 through 2008

Period	Coal[1] Receipts (thousand tons)	Coal[1] Average Cost (cents per MMBtu)	Coal[1] Average Cost (dollars/ ton)	Coal[1] Avg. Sulfur Percent by Weight	Petroleum[2] Receipts (thousand barrels)	Petroleum[2] Average Cost (cents per MMBtu)	Petroleum[2] Average Cost (dollars/ barrel)	Petroleum[2] Avg. Sulfur Percent by Weight[4]	Natural Gas[3] Receipts (thousand Mcf)	Natural Gas[3] Average Cost (cents per MMBtu)	All Fossil Fuels Average Cost (cents per MMBtu)
1997	880,588	127	26.16	1.11	128,749	273	17.18	1.37	2,764,734	276	152
1998	929,448	125	25.64	1.06	181,276	202	12.71	1.48	2,922,957	238	144
1999	908,232	122	24.72	1.01	145,939	236	14.81	1.51	2,809,455	257	144
2000	790,274	120	24.28	.93	108,272	418	26.30	1.33	2,629,986	430	174
2001	762,815	123	24.68	.89	124,618	369	23.20	1.42	2,148,924	449	173
2002[5]	884,287	125	25.52	.94	120,851	334	20.77	1.64	5,607,737	356	186
2003	986,026	128	26.00	.97	185,567	433	26.78	1.53	5,500,704	539	228
2004	1,002,032	136	27.42	.97	186,655	429	26.56	1.66	5,734,054	596	248
2005	1,021,437	154	31.20	.98	194,733	644	39.65	1.61	6,181,717	821	325
2006	1,079,943	169	34.09	.97	100,965	623	37.66	2.31	6,675,246	694	302
2007	1,054,664	177	35.48	.96	88,347	717	43.50	2.10	7,200,316	711	323
2008	1,069,709	207	41.14	.97	96,341	1,087	64.89	2.21	7,879,046	902	411

[1] Anthracite, bituminous, subbituminous, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.
[4] Beginning in 2006, receipts of petroleum liquids went down substantially, while the receipts of petroleum coke remained the nearly the same. The Average Sulfur Percent by Weight is higher beginning in 2006 as a result the greater influence by petroleum coke receipts, which has higher sulfur content, than the petroleum liquid receipts.
[5] Beginning in 2002, data from the historical Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historical FERC Form 423.

Notes: • Mcf equals 1,000 cubic feet. Totals may not equal sum of components because of independent rounding. • Beginning in 2008 with the Form EIA-923, receipts, cost, and quality data are imputed for plants between 1 and 50 MW, in addition to the data collected from plants above the 50 MW threshold. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3.6. Receipts and Quality of Coal Delivered for the Electric Power Industry, 1997 through 2008

Period	Anthracite[1] Receipts (thousand tons)	Anthracite[1] Avg. Sulfur Percent by Weight	Anthracite[1] Avg. Ash Percent by Weight	Bituminous[1] Receipts (thousand tons)	Bituminous[1] Avg. Sulfur Percent by Weight	Bituminous[1] Avg. Ash Percent by Weight	Subbituminous Receipts (thousand tons)	Subbituminous Avg. Sulfur Percent by Weight	Subbituminous Avg. Ash Percent by Weight	Lignite Receipts (thousand tons)	Lignite Avg. Sulfur Percent by Weight	Lignite Avg. Ash Percent by Weight
1997	751	.53	36.7	466,104	1.65	10.5	336,805	.40	6.7	76,928	.98	13.8
1998	511	.55	37.6	478,252	1.61	10.5	373,496	.38	6.6	77,189	.95	13.8
1999	137	.64	37.8	444,399	1.57	10.2	386,271	.38	6.6	77,425	.90	14.2
2000	11	.64	37.2	375,673	1.45	10.1	341,242	.35	6.3	73,349	.91	14.2
2001	--	--	--	348,703	1.42	10.4	349,340	.35	6.1	64,772	.98	13.9
2002[2]	--	--	--	412,589	1.47	10.1	391,785	.36	6.2	65,555	.93	13.3
2003	--	--	--	436,809	1.49	9.9	432,513	.38	6.4	79,869	1.03	14.4
2004	--	--	--	441,186	1.50	10.3	445,603	.36	6.0	78,268	1.05	14.2
2005	--	--	--	451,680	1.55	10.5	456,856	.36	6.2	77,677	1.02	14.0
2006	--	--	--	462,992	1.57	10.5	504,947	.35	6.1	75,742	.95	14.4
2007	--	--	--	439,154	1.61	10.3	505,155	.34	6.0	71,930	.90	14.0
2008	--	--	--	463,943	1.68	10.6	522,228	.34	5.8	68,945	.86	13.8

[1] Beginning in 2001, anthracite coal receipts were no longer reported separately. From 2001 forward, all anthracite coal receipts have been combined with bituminous coal receipts.
[2] Beginning in 2002, data from the historical Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historical FERC Form 423.

Notes: • Totals may not equal sum of components because of independent rounding. • Beginning in 2008 with the Form EIA-923, receipts, cost, and quality data are imputed for plants between 1 and 50 MW, in addition to the data collected from plants above the 50 MW threshold. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3.7. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 1997 through 2008

Year	Coal[1]			Petroleum[2]		Natural Gas[3]
	Average Btu per Pound	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Gallon	Average Sulfur Percent by Weight[4]	Average Btu per Cubic Foot
1997	10,275	1.11	9.36	149,838	1.37	1,019
1998	10,241	1.06	9.18	149,736	1.48	1,022
1999	10,163	1.01	9.01	149,407	1.51	1,019
2000	10,115	.93	8.84	149,857	1.33	1,020
2001	10,200	.89	8.80	147,857	1.42	1,020
2002[5]	10,168	.94	8.74	147,902	1.64	1,025
2003	10,137	.97	8.98	147,086	1.53	1,030
2004	10,074	.97	8.97	147,286	1.66	1,027
2005	10,107	.98	9.02	146,481	1.61	1,028
2006	10,063	.97	9.03	143,883	2.31	1,027
2007	10,028	.96	8.84	144,545	2.10	1,027
2008	9,947	.97	8.95	142,205	2.21	1,027

[1] Anthracite, bituminous, subbituminous, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.
[4] Beginning in 2006, receipts of petroleum liquids went down substantially, while the receipts of petroleum coke remained the nearly the same. The Average Sulfur Percent by Weight is higher beginning in 2006 as a result the greater influence by petroleum coke receipts, which has higher sulfur content, than the petroleum liquid receipts.
[5] Beginning in 2002, data from the historical Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historical FERC Form 423.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3.8. Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 1997 through 2008

Period	Coal								Petroleum		Natural Gas		Total Fossil Fuels	
	Bituminous		Subbituminous		Lignite		All Coal Ranks							
	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)
1997	11,203	135	5,885	119	997	93	18,096	127	810	273	2,818	276	21,724	152
1998	11,510	135	6,520	113	999	94	19,036	125	1,140	202	2,986	238	23,162	144
1999	10,722	131	6,740	110	996	93	18,461	122	916	236	2,862	257	22,238	144
2000	9,050	130	5,991	108	947	94	15,988	120	681	418	2,682	430	19,351	174
2001	8,312	139	6,134	104	839	109	15,286	123	783	369	2,209	449	18,278	173
2002	9,932	142	6,878	105	851	104	17,982	125	751	334	5,750	356	24,483	186
2003	10,543	144	7,598	110	1,026	103	19,990	128	1,146	433	5,663	539	26,799	228
2004	10,538	156	7,817	112	1,012	106	20,189	136	1,155	429	5,891	596	27,234	248
2005	10,833	184	8,004	119	1,008	107	20,647	154	1,198	644	6,357	821	28,202	325
2006	11,129	204	8,842	131	982	115	21,735	169	610	623	6,856	694	29,201	302
2007	10,580	208	8,826	145	925	128	21,152	177	536	717	7,396	711	29,085	323
2008	11,110	250	9,087	162	896	141	21,280	207	575	1,087	8,089	902	29,945	411

Notes: • Totals may not equal sum of components because of independent rounding. • Beginning in 2008 with the Form EIA-923, receipts, cost, and quality data are imputed for plants between 1 and 50 MW, in addition to the data collected from plants above the 50 MW threshold. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3.9. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, 1997 through 2008

(Thousand Metric Tons)

Emission	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Carbon Dioxide (CO_2).....	2,477,213	2,539,805R	2,481,829R	2,536,675R	2,479,971R	2,438,338R	2,417,327R	2,412,030R	2,464,550R	2,360,424R	2,345,951R	2,253,783R
Sulfur Dioxide (SO_2)	7,830	9,042	9,524	10,340	10,309	10,646	10,881	11,174	11,963	12,843	13,464	13,480
Nitrogen Oxides (NO_x)	3,330	3,650	3,799	3,961	4,143	4,532	5,194	5,290	5,638	5,955	6,459	6,500

R = Revised.

Notes: • The emissions data presented include total emissions from both electricity generation and the production of useful thermal output. • See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates. • CO2 emissions for the historical years 1997-2007 have been revised due to changes in the conventions used to determine fuel combustion. • SO2 and NOx 2008 values in Table 3.9 are preliminary.

Source: Calculations made by the Electric Power Division, Energy Information Administration.

Table 3.10. Number and Capacity of Fossil-Fuel Steam-Electric Generators with Environmental Equipment, 1997 through 2008

Year	Flue Gas Desulfurization (Scrubbers)		Particulate Collectors		Cooling Towers		Total[1]	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
1997....................................	183	86,605	1,133	352,068	480	166,886	1,301	377,195
1998....................................	186	87,783	1,130	351,790	474	166,896	1,294	377,117
1999....................................	192	89,666	1,148	353,480	505	175,520	1,343	387,192
2000....................................	192	89,675	1,141	352,727	505	175,520	1,336	386,438
2001....................................	236	97,988	1,273	360,762	616	189,396	1,485	390,821
2002....................................	243	98,673	1,256	359,338	670	200,670	1,522	401,341
2003....................................	246	99,567	1,244	358,009	695	210,928	1,546	409,954
2004....................................	248	101,492	1,217	355,782	732	214,989	1,536	409,769
2005....................................	248	101,648	1,216	355,599	730	217,646	1,535	411,840
2006....................................	NA	NA	NA	NA	NA	NA	NA	NA
2007....................................	279	119,049	1,192	354,572	774	229,199	1,554	421,781
2008....................................	330	140,263	1,194	355,764	795	234,920	1,568	426,812

[1] Components are not additive since some generators are included in more than one category.

[2] Nameplate capacity

NA = Not available. Form EIA-767 data collection was suspended in the data year 2006.

Notes: • These data are for plants with a fossil-fueled steam-electric capacity of 100 megawatts or more . • Data for Independent Power Producer and Combined Heat and Power plants are included beginning with 2001 data. • Totals may not equal sum of components because of independent rounding.

Sources: Through 2005, Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report;" and from 2007 forward, Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 3.11. Average Flue Gas Desulfurization Costs, 1997 through 2008

Year	Average Operation & Maintenance Costs (mills per kilowatthour)[1]	Average Installed Capital Costs (dollars per kilowatt)
1997...	1.09	129.00
1998...	1.12	126.00
1999...	1.13	125.00
2000...	.96	124.00
2001...	1.27	130.80
2002...	1.11	124.18
2003...	1.23	123.75
2004...	1.38	144.64
2005...	1.23	141.34
2006...	NA	NA
2007...	1.52	135.37
2008...	1.55	149.57

[1] A mill is one tenth of one cent.

NA = Not available. Form EIA-767 data collection was suspended in the data year 2006.

Notes: • These data are for plants with a fossil-fueled steam-electric capacity of 100 megawatts or more. • Beginning in 2001, data for plants with a fossil-fueled or combustible renewable steam-electric capacity of 10 megawatts or more were also included. • Data for Independent Power Producer and Combined Heat and Power plants are included beginning with 2001 data. • Totals may not equal sum of components because of independent rounding.

Sources: Through 2005, Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report;" and from 2007 forward, Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" for Average Installed Capital Costs, and Form EIA-923, "Power Plant Operations Report" for Average Operation & Maintenance Costs.

Chapter 4. Demand, Capacity Resources, and Capacity Margins

Table 4.1. Noncoincident Peak Load, Actual and Projected by North American Electric Reliability Corporation Region, 2004 through 2013
(Megawatts)

North American Electric Reliability Corporation Regional Entity	Actual				
	2004	2005	2006	2007	2008
Summer					
ECAR[1]	95,300	NA	NA	NA	NA
ERCOT	58,531	60,210	62,339	62,188	62,174
FRCC	42,383	46,396	45,751	46,676	44,836
MAAC[1]	52,049	NA	NA	NA	NA
MAIN[1]	53,439	NA	NA	NA	NA
MRO (U.S.) [2]	29,351	39,918	42,194	41,684	39,677
NPCC (U.S.)	52,549	58,960	63,241	58,314	58,543
Reliability*First*[3]	NA	190,200	191,920	181,700	169,155
SERC	157,615	190,705	199,052	209,109	199,779
SPP	40,106	41,727	42,882	43,167	43,476
WECC (U.S.)	123,136	130,760	142,096	139,389	134,829
Contiguous U.S.	**704,459**	**758,876**	**789,475**	**782,227**	**752,470**
Winter					
ECAR[1]	91,800	NA	NA	NA	NA
ERCOT	44,010	48,141	50,402	50,408	47,806
FRCC	44,839	42,657	42,526	41,701	45,275
MAAC[1]	45,905	NA	NA	NA	NA
MAIN[1]	42,929	NA	NA	NA	NA
MRO (U.S.) [2]	24,526	33,748	34,677	33,191	36,029
NPCC (U.S.)	48,176	46,828	46,697	46,795	46,043
Reliability*First*[3]	NA	151,600	149,631	141,900	142,395
SERC	144,337	164,638	175,163	179,888	179,596
SPP	29,490	31,260	30,792	31,322	32,809
WECC (U.S.)	102,689	107,493	111,093	112,700	113,605
Contiguous U.S.	**618,701**	**626,365**	**640,981**	**637,905**	**643,557**

North American Electric Reliability Corporation Regional Entity	Projected				
	2009	2010	2011	2012	2013
Summer					
TRE (formerly ERCOT)	63,491	64,056	65,494	67,394	69,399
FRCC	45,734	45,794	46,410	47,423	48,304
MRO (U.S.) [2]	43,172	44,184	45,038	45,707	46,337
NPCC (U.S.)	61,327	61,601	62,268	62,926	63,445
Reliability*First*[3]	178,100	180,400	185,700	189,700	192,100
SERC	202,738	206,218	211,528	215,641	219,712
SPP	44,462	45,113	45,988	46,616	47,255
WECC (U.S.)	140,692	142,750	145,185	147,758	150,163
Contiguous U.S.	**779,716**	**790,116**	**807,611**	**823,165**	**836,715**
Winter					
TRE (formerly ERCOT)	43,463	44,463	45,784	47,030	47,984
FRCC	44,446	45,099	46,140	46,971	47,709
MRO (U.S.) [2]	36,571	36,884	37,613	38,125	38,483
NPCC (U.S.)	47,098	47,076	47,195	47,384	47,620
Reliability*First*[3]	145,800	148,000	151,800	153,800	155,100
SERC	181,045	183,608	187,639	190,266	193,586
SPP	32,636	33,308	33,864	34,421	34,961
WECC (U.S.)	111,324	113,096	114,832	116,522	118,280
Contiguous U.S.	**642,383**	**651,534**	**664,867**	**674,519**	**683,723**

[1] ECAR, MAAC, and MAIN dissolved at the end of 2005. Utility membership joined other reliability regional councils. Also, see Footnote 3.
[2] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[3] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.

NA = Not available.

Notes: • Projected data are updated annually, so revision superscript is not used. • Nerc Regions are provided in Appendix A., Technical Notes. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • The winter peak period begins on December 1 and extends through the end of February of the following year • The MRO, SERC, and SPP regional boundaries were altered as a variety of utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 4.2. Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Corporation Region, Summer, 1997 through 2008

(Megawatts)

Regional Entity and Item	2008[1]	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
ECAR[2]												
Net Internal Demand[3]	NA	NA	NA	NA	95,300	98,487	101,251	100,235	98,651	94,072	92,359	91,103
Capacity Resources[4]...................	NA	NA	NA	NA	127,919	123,755	119,736	113,136	115,379	107,451	105,545	105,106
Capacity Margin (percent)[5].........	NA	NA	NA	NA	25.5	20.4	15.4	11.4	14.5	12.5	12.5	13.3
TRE (formerly ERCOT)												
Net Internal Demand[3]	61,049	61,063[R]	61,214[R]	59,060	58,531	59,282	55,833	55,106	53,649	51,697	50,254	47,746
Capacity Resources[4]...................	74,274	75,912[R]	70,664[R]	66,724	73,850	74,764	76,849	70,797	69,622	65,423	59,788	55,771
Capacity Margin (percent)[5].........	17.8	19.6[R]	13.4[R]	11.5	20.7	20.7	27.3	22.2	22.9	21.0	15.9	14.4
FRCC												
Net Internal Demand[3]	44,660	46,434[R]	45,345[R]	45,950	42,243	40,387	37,951	38,932	35,666	34,832	34,562	32,874
Capacity Resources[4]...................	51,541	53,027[R]	50,909[R]	50,200	48,579	46,806	43,342	42,290	43,083	40,645	39,708	39,613
Capacity Margin (percent)[5].........	13.4	12.4[R]	10.9[R]	8.5	13.0	13.7	12.4	7.9	17.2	14.3	13.0	17.0
MAAC[2]												
Net Internal Demand[3]	NA	NA	NA	NA	52,049	53,566	54,296	54,015	51,358	49,325	47,626	46,548
Capacity Resources[4]...................	NA	NA	NA	NA	66,167	65,897	63,619	59,533	60,679	57,831	55,511	56,155
Capacity Margin (percent)[5].........	NA	NA	NA	NA	21.3	18.7	14.7	9.3	15.4	14.7	14.2	17.1
MAIN[2]												
Net Internal Demand[3]	NA	NA	NA	NA	50,499	53,617	53,267	53,032	51,845	47,165	45,570	45,194
Capacity Resources[4]...................	NA	NA	NA	NA	65,677	67,410	67,025	65,950	64,170	55,984	52,722	52,160
Capacity Margin (percent)[5].........	NA	NA	NA	NA	23.1	20.5	20.5	19.6	19.2	15.8	13.6	13.4
MRO (U.S.)[6]												
Net Internal Demand[3]	38,857	40,249[R]	40,661[R]	38,266	29,094	28,775	28,825	27,125	28,006	30,606	29,766	28,221
Capacity Resources[4]...................	48,180	47,259[R]	50,116[R]	46,792	35,830	33,287	34,259	32,271	34,236	35,373	34,773	34,027
Capacity Margin (percent)[5].........	19.3	14.8[R]	18.9[R]	18.2	18.8	13.6	15.9	15.9	18.2	13.5	14.4	17.1
NPCC (U.S.)												
Net Internal Demand[3]	59,896	58,221[R]	60,879[R]	57,402	51,580	53,936	55,164	55,888	54,270	53,450	51,760	50,240
Capacity Resources[4]...................	75,894	73,771[R]	73,095[R]	72,258	71,532	70,902	66,208	63,760	63,376	63,077	60,439	60,729
Capacity Margin (percent)[5].........	21.1	21.1[R]	16.7[R]	20.6	27.9	23.9	16.7	12.3	14.4	15.3	14.4	17.3
Reliability*First*[7]												
Net Internal Demand[3]	169,155	177,200	190,800[R]	190,200	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Resources[4]...................	215,477	213,544[R]	214,693[R]	220,000	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Margin (percent)[5].........	21.5	17.0[R]	11.1[R]	13.5	NA	NA	NA	NA	NA	NA	NA	NA
SERC												
Net Internal Demand[3]	196,711	205,321[R]	196,196[R]	186,049	153,024	148,380	154,459	144,399	151,527	142,726	138,146	134,968
Capacity Resources[4]...................	228,169	234,232[R]	223,630[R]	219,749	182,861	177,231	172,485	171,530	169,760	160,575	158,360	155,016
Capacity Margin (percent)[5].........	13.8	12.3[R]	12.3[R]	15.3	16.3	16.3	10.5	15.8	10.7	11.1	12.8	12.9
SPP												
Net Internal Demand[3]	42,906	42,459[R]	41,982[R]	41,079	39,383	39,428	38,298	38,807	39,056	37,807	36,402	37,009
Capacity Resources[4]...................	48,110	48,573[R]	45,831[R]	46,376	48,000	45,802	47,233	45,530	46,109	43,111	42,554	43,591
Capacity Margin (percent)[5].........	10.8	12.6[R]	8.4[R]	11.4	18.0	13.9	18.9	14.8	15.3	12.3	14.5	15.1
WECC (U.S.)												
Net Internal Demand[3]	130,916	135,839[R]	139,402[R]	128,464	121,205	120,894	117,032	107,294	116,913	112,177	111,641	104,486
Capacity Resources[4]...................	167,860	168,080[R]	162,288[R]	160,026	155,455	150,277	142,624	124,193	141,640	136,274	135,270	135,687
Capacity Margin (percent)[5].........	22.0	19.2[R]	14.1[R]	19.7	22.0	19.6	17.9	13.6	17.5	17.7	17.5	23.0
Contiguous U.S.												
Net Internal Demand[3]..............	**744,151**	**766,786[R]**	**776,479[R]**	**746,470**	**692,908**	**696,752**	**696,376**	**674,833**	**680,941**	**653,857**	**638,086**	**618,389**
Capacity Resources[4].................	**909,504**	**914,397[R]**	**891,226[R]**	**882,125**	**875,870**	**856,131**	**833,380**	**788,990**	**808,054**	**765,744**	**744,670**	**737,855**
Capacity Margin (percent)[5]	**18.2**	**16.1[R]**	**12.9[R]**	**15.4**	**20.9**	**18.6**	**16.4**	**14.5**	**15.7**	**14.6**	**14.3**	**16.2**

[1] Updated June 2010.
[2] ECAR, MAAC, and MAIN dissolved at the end of 2005. Utility membership joined other reliability regional councils. Also, see Footnote 6.
[3] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[4] Capacity Resources: Utility- and IPP-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.
[5] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
[6] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[7] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.

NA = Not available.

R = Revised.

Notes: • Nerc Regions are provided in Appendix A., Technical Notes. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • The MRO, SERC, and SPP regional boundaries were altered as a variety of utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 4.3. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Corporation Region, Summer, 2008 through 2013
(Megawatts)

North American Electric Reliability Corporation Regional Entity	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]
	2008[4]			2009		
TRE (formerly ERCOT)	61,049	74,274	17.8	62,376	72,204	13.6
FRCC	44,660	51,541	13.4	42,531	51,870	18.0
MRO (U.S.)[5]	38,857	48,180	19.3	41,306	50,308	17.9
NPCC (U.S.)	59,896	75,894	21.1	61,108	76,671	20.3
Reliability*First*[6]	169,155	215,477	21.5	169,900	215,800	21.3
SERC	196,711	228,169	13.8	196,871	244,008	19.3
SPP	42,906	48,110	10.8	43,696	50,127	12.8
WECC (U.S.)	130,916	167,860	22.0	136,441	174,978	22.0
Contiguous U.S.	**744,151**	**909,504**	**18.2**	**754,229**	**935,965**	**19.4**
	2010			2011		
TRE (formerly ERCOT)	62,941	76,049	17.2	64,379	76,714	16.1
FRCC	42,511	53,198	20.1	43,028	54,830	21.5
MRO (U.S.)[5]	42,316	49,836	15.1	43,142	50,266	14.2
NPCC (U.S.)	61,382	75,450	18.6	62,049	79,862	22.3
Reliability*First*[6]	172,200	217,300	20.8	177,500	220,100	19.4
SERC	199,621	246,543	19.0	204,405	250,917	18.5
SPP	44,349	51,682	14.2	45,093	52,415	14.0
WECC (U.S.)	137,739	184,432	25.3	139,456	193,787	28.0
Contiguous U.S.	**763,059**	**954,489**	**20.1**	**779,052**	**978,890**	**20.4**
	2012			2013		
TRE (formerly ERCOT)	66,279	77,686	14.7	68,284	79,521	14.1
FRCC	43,944	55,611	21.0	44,697	57,464	22.2
MRO (U.S.)[5]	43,845	50,286	12.8	44,482	50,218	11.4
NPCC (U.S.)	62,707	80,171	21.8	63,226	78,207	19.2
Reliability*First*[6]	181,500	219,600	17.3	183,900	219,600	16.3
SERC	208,091	254,132	18.1	211,900	253,404	16.4
SPP	45,613	53,074	14.1	46,153	53,477	13.7
WECC (U.S.)	141,499	201,597	29.8	143,988	204,058	29.4
Contiguous U.S.	**793,478**	**992,157**	**20.0**	**806,630**	**995,948**	**19.0**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] Capacity Resources: Utility- and IPP-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
[4] Updated June 2010.
[5] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[6] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.
Notes: • Actual data are final. • Projected data are updated annually, so revision superscript is not used. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • The MRO, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 4.4. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Corporation Region, Winter, 2008 through 2013
(Megawatts)

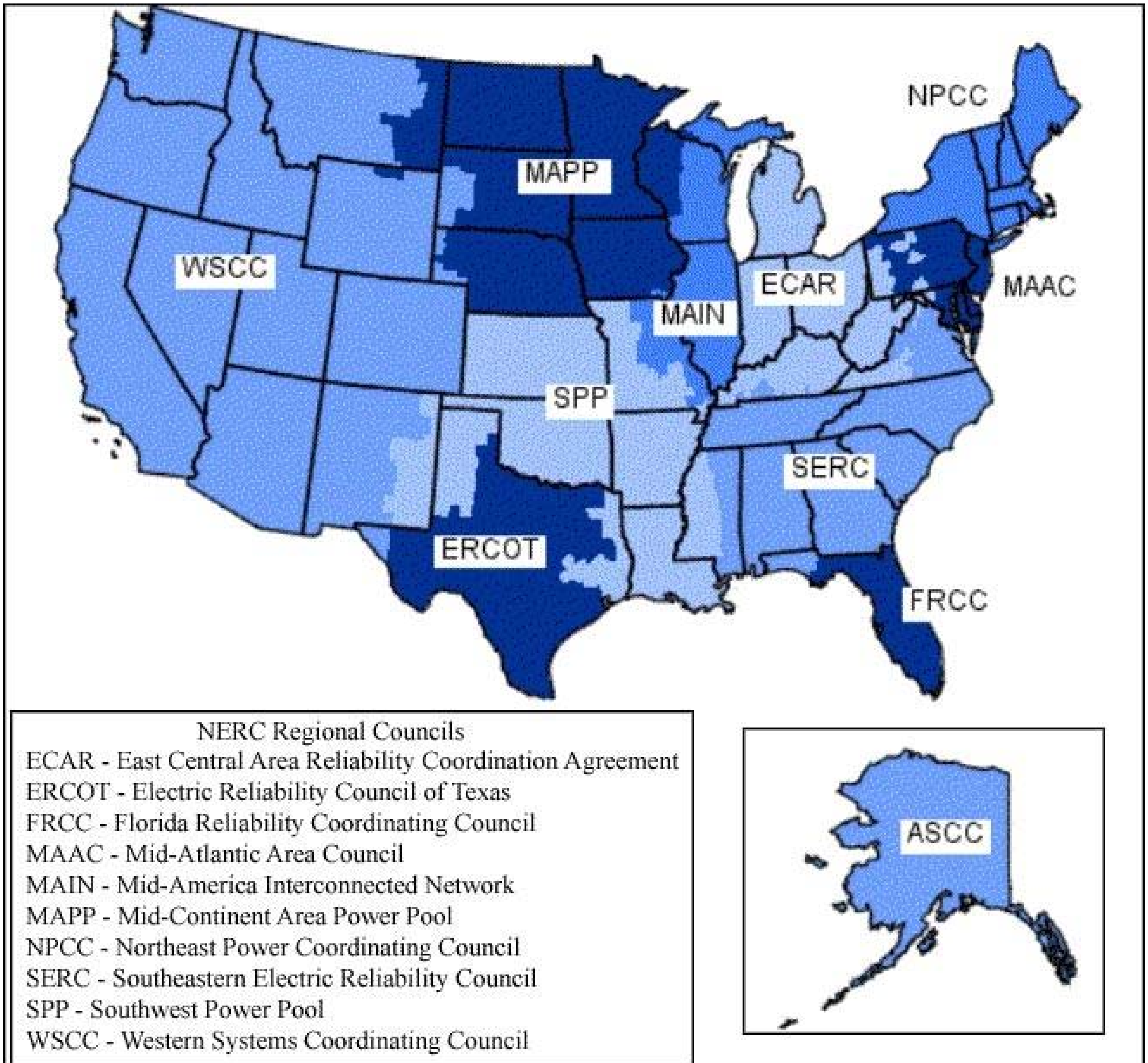
North American Electric Reliability Corporation Regional Entity	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[2]
	2008/ 2009[4]			2009/ 2010		
TRE (formerly ERCOT)	46,747	73,910	36.8	42,348	74,797	43.4
FRCC	45,042	53,278	15.5	40,846	57,216	28.6
MRO (U.S.)[5]	34,539	47,343	27.0	34,985	48,417	27.7
NPCC (U.S.)	47,151	79,394	40.6	47,098	77,577	39.3
Reliability*First*[6]	142,395	215,477	33.9	140,900	218,100	35.4
SERC	175,199	234,797	25.4	175,541	251,192	30.1
SPP	32,362	48,226	32.9	31,988	49,535	35.4
WECC (U.S.)	110,977	167,312	33.7	108,535	173,502	37.4
Contiguous U.S.	**634,412**	**919,736**	**31.0**	**622,241**	**950,335**	**34.5**
	2010/ 2011			2011/ 2012		
TRE (formerly ERCOT)	43,348	77,806	44.3	44,669	78,473	43.1
FRCC	41,411	57,302	27.7	42,367	59,873	29.2
MRO (U.S.)[5]	35,653	48,869	27.0	36,228	49,094	26.2
NPCC (U.S.)	47,076	73,679	36.1	47,195	76,444	38.3
Reliability*First*[6]	143,100	219,600	34.8	146,900	222,400	33.9
SERC	177,738	250,181	29.0	181,557	254,232	28.6
SPP	32,650	51,293	36.3	33,101	51,825	36.1
WECC (U.S.)	110,007	180,655	39.1	111,461	187,104	40.4
Contiguous U.S.	**630,983**	**959,385**	**34.2**	**643,478**	**979,445**	**34.3**
	2012/ 2013			2013/ 2014		
TRE (formerly ERCOT)	45,915	79,441	42.2	46,869	81,233	42.3
FRCC	43,080	60,308	28.6	43,813	62,001	29.3
MRO (U.S.)[5]	36,754	49,266	25.4	37,119	49,299	24.7
NPCC (U.S.)	47,384	76,784	38.3	47,620	76,768	38.0
Reliability*First*[6]	148,900	221,900	32.9	150,200	221,900	32.3
SERC	184,160	256,332	28.2	187,364	256,459	26.9
SPP	33,571	52,540	36.1	34,022	52,933	35.7
WECC (U.S.)	113,145	191,746	41.0	114,867	193,056	40.5
Contiguous U.S.	**652,909**	**988,316**	**33.9**	**661,874**	**993,649**	**33.4**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] Capacity Resources: Utility- and IPP-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
[4] Updated June 2010.
[5] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[6] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.

Notes: • Actual data are final. • Projected data are updated annually, so revision superscript is not used. • Represents an hour of a day during the associated peak period. • The winter peak period begins on December 1 and extends through the end of February of the following year. For example, winter 2004/2005 begins December 1, 2004, and extends to February 28, 2005 • The MRO, SERC, and SPP regional boundaries were altered as a variety of utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.

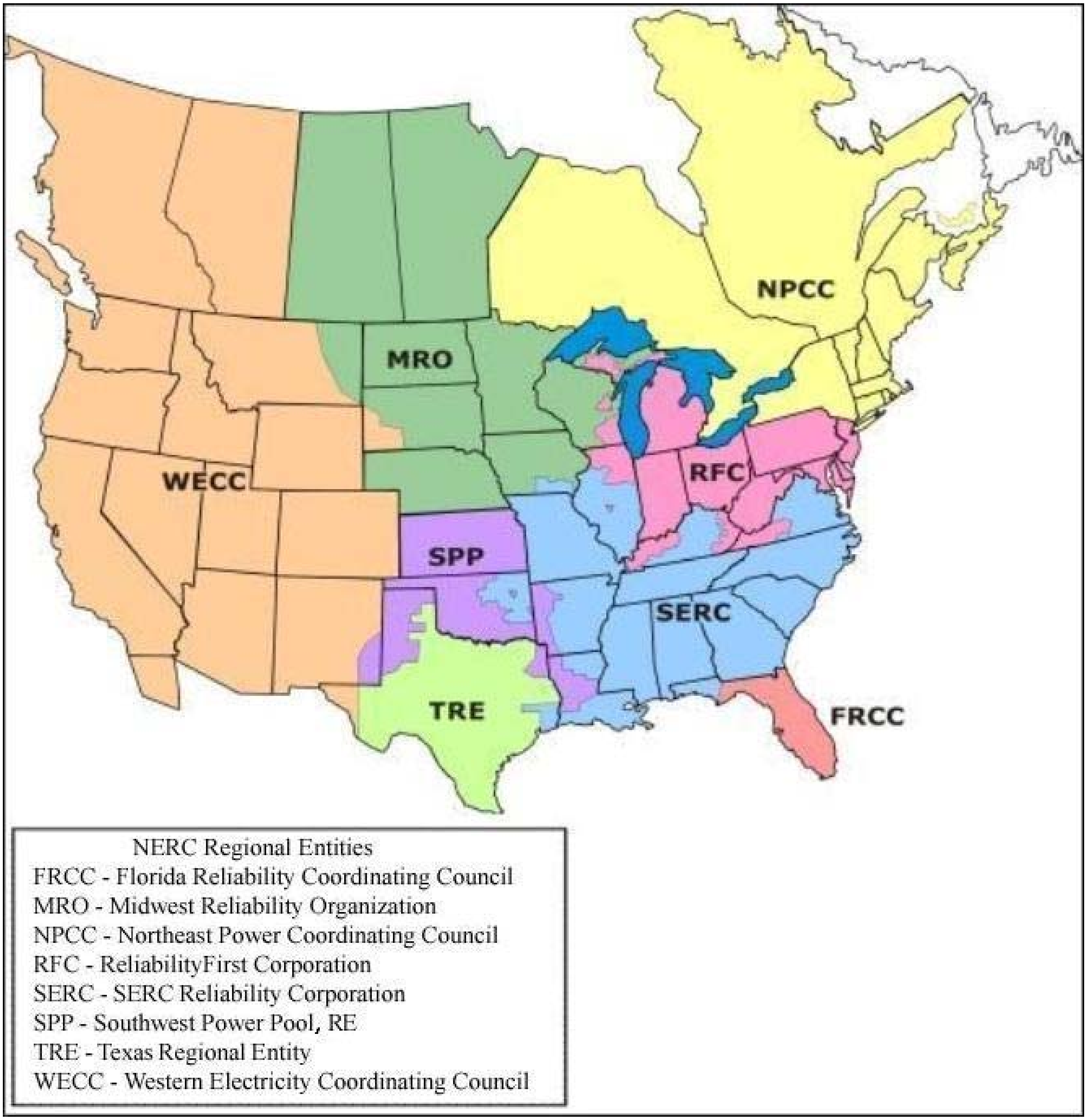
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Figure 4.1 Historical North American Electric Reliability Council Regions for the Contiguous U.S., 2005



Note: The Alaska Systems Coordinating Council (ASCC) was an affiliate NERC member.
Source: U.S.Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Figure 4.2   Consolidated North American Electric Reliability Corporation Regional Entities, 2008



Chapter 5. Characteristics of the Electric Power Industry

Table 5.1. Count of Electric Power Industry Power Plants, by Sector, by Predominant Energy Sources within Plant, 2001 through 2008
(Count)

Period	Coal	Petroleum	Natural Gas	Other Gases	Nuclear	Hydroelectric Conventional	Other Renewables	Hydroelectric Pumped Storage	Other
Total (All Sectors)									
2001	645	1,160	1,576	35	66	1,421	672	37	14
2002	633	1,186	1,649	40	66	1,426	684	38	26
2003	629	1,206	1,696	40	66	1,425	745	38	25
2004	626	1,201	1,677	46	66	1,425	752	39	26
2005	620	1,210	1,671	44	66	1,422	783	39	27
2006	617	1,215	1,663	46	66	1,421	845	39	27
2007	607	1,198	1,659	46	66	1,424	931	39	24
2008	599	1,205	1,653	43	66	1,423	1,080	39	29
Electricity Generators, Electric Utilities									
2001	373	827	646	1	43	905	48	33	1
2002	365	839	670	1	43	907	49	34	--
2003	356	856	672	1	42	900	58	34	1
2004	354	853	680	1	41	895	61	35	1
2005	347	851	719	--	37	896	66	34	1
2006	345	858	741	1	36	894	83	34	1
2007	341	854	746	1	34	890	91	34	1
2008	338	872	765	--	34	886	106	34	1
Electricity Generators, Independent Power Producers									
2001	100	177	295	--	23	447	429	4	--
2002	102	189	351	2	23	451	438	4	2
2003	100	191	391	1	24	463	475	4	--
2004	103	186	400	1	25	467	483	4	--
2005	108	196	383	2	29	464	506	5	--
2006	109	188	373	2	30	465	554	5	--
2007	109	189	381	1	32	477	628	5	--
2008	106	187	372	--	32	481	755	5	2
Combined Heat and Power, Electric Power									
2001	46	14	154	3	--	1	30	--	1
2002	47	16	170	2	--	--	31	--	--
2003	49	18	192	3	--	1	37	--	--
2004	48	17	186	4	--	1	33	--	--
2005	47	15	184	4	--	1	36	--	--
2006	50	19	177	4	--	1	35	--	--
2007	50	15	175	4	--	--	34	--	--
2008	50	14	170	3	--	--	38	--	--
Combined Heat and Power, Commercial[1]									
2001	20	63	127	--	--	9	39	--	--
2002	20	63	123	--	--	10	37	--	--
2003	22	65	121	--	--	10	41	--	--
2004	21	68	121	1	--	10	42	--	--
2005	20	71	113	1	--	9	45	--	--
2006	22	71	109	1	--	9	45	--	--
2007	20	68	106	1	--	9	45	--	1
2008	20	66	106	1	--	9	48	--	1
Combined Heat and Power, Industrial[1]									
2001	106	79	354	31	--	59	126	--	12
2002	99	79	335	35	--	58	129	--	24
2003	102	76	320	35	--	51	134	--	24
2004	100	77	290	39	--	52	133	--	25
2005	98	77	272	37	--	52	130	--	26
2006	91	79	263	38	--	52	128	--	26
2007	87	72	251	39	--	48	133	--	22
2008	85	66	240	39	--	47	133	--	25

[1] Small number of electricity-only, non-Combined Heat and Power plants may be included.

Note: The number of power plants for each energy source is the number of sites for which the respective energy source was reported as the most predominant energy source for at least one of its generators. If all generators for a site have the same energy source reported as the most predominant, that site will be counted once under that energy source. However, if the most predominant energy source is not the same for all generators within a site, the site is counted more than once, based on the number of most predominant energy sources for generators at a site. In general, this table translates the number of generators by energy source (Table 1.2) into the number of sites represented by the generators for an energy source. Therefore, the count for Total (All Sectors) is the sum of the counts for each sector by energy source and does not necessarily represent unique sites

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 5.2. Average Capacity Factors by Energy Source, 1997 through 2008
(Percent)

Year	Coal	Petroleum	Natural Gas CC[1]	Natural Gas Other	Nuclear	Hydroelectric Conventional	Other Renewables	All Energy Sources
1997	67.2	14.6	--	31.6	72.0	51.2	57.4	52.4
1998	67.7	22.2	--	34.2	79.2	46.6	57.0	54.6
1999	68.1	22.4	--	33.2	85.3	45.9	56.9	54.9
2000	71.0	20.5	--	37.1	87.7	39.5	59.1	54.6
2001	69.2	21.5	--	35.7	89.4	31.4	50.2	51.4
2002	70.0	18.1	--	38.2	90.3	38.0	54.0	49.7
2003	72.0	22.4	33.5	12.1	87.9	40.0	50.0	47.7
2004	71.9	23.3	35.5	10.7	90.1	39.4	50.5	47.9
2005	73.3	23.8	36.8	10.6	89.3	39.8	47.0	48.3
2006	72.6	12.6	38.8	10.7	89.6	42.4	45.7	48.0
2007	73.6	13.4	42.0	11.4	91.8	36.3	40.0	48.7
2008	72.2	9.2	40.7	10.6	91.1	37.2	37.3	47.4

[1] Prior to 2003, the generation collected on Form EIA-906 did not have a distinction for combined cycle (CC) prime movers. All natural gas-fired plants of all types are included in "Natural Gas Other" for 1997 to 2002.

Technical Note: Average Capacity Factor is the ratio of actual generation to maximum potential output, expressed as a percent.
Average Capacity Factor = [(Net Generation)/(Net Summer Capacity* Number of Hours in the Year)] * 100
for the respective energy source and year

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Form EIA-923, Power Plant Operations Report," and predecessor forms.

Table 5.3. Average Operating Heat Rate for Selected Energy Sources, 2001 through 2008
(Btu per Kilowatthour)

Year	Coal[1]	Petroleum[2]	Natural Gas	Nuclear
2001	10,378	10,742	10,051	10,443
2002	10,314	10,641	9,533	10,442
2003	10,297	10,610	9,207	10,421
2004	10,331	10,571	8,647	10,427
2005	10,373	10,631	8,551	10,436
2006	10,351	10,809	8,471	10,436
2007	10,375	10,794	8,403	10,485
2008	10,378	11,015	8,305	10,453

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste coal and synthetic coal are included starting in 2002.
[2] Includes distillate fuel oil (all diesel and No. 1 and No. 2 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil, jet fuel, kerosene, petroleum coke, and waste oil.
Notes: • Included in the calculation for coal, petroleum, and natural gas average operating heat rate are electric power plants in the utility and independent power producer sectors. • Combined heat and power plants, and all plants in the commercial and industrial sectors are excluded from the calculations. • The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860.
Technical Note: The average operating heat rate for coal, petroleum and natural gas displayed in Table 5.3 is calculated by dividing the energy consumed (in BTUs) to generate electricity by the kilowatthours of power generated as reported on the Form EIA-923 and its predecessor forms. Included in the calculation for coal, petroleum and natural gas are utility and independent power producer plants. The calculation excludes combined heat and power plants, industrial plants, and commercial sector plants. The nuclear heat rate is a weighted average (by capacity) of the tested heat rate as reported on the Form EIA-860.
Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report."

Table 5.4. Average Heat Rates by Prime Mover and Energy Source, 2008
(Btu per Kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas	Nuclear
Steam Turbine	10,138	10,360	10,389	10,453
Gas Turbine	--	13,322	11,526	--
Internal Combustion	--	10,271	10,014	--
Combined Cycle	W	11,044	7,598	--

W = Withheld to avoid disclosure of individual company data.
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • Heat rate is reported at full load conditions for electric utilities and independent power producers.
Technical Note: The heat rates reported on Form EIA-860 are weighted by Net Summer Capacity.
Average Heat Rate = Sum of [Reported Heat Rate * (NSC/Total Capacity)] where
NSC = Net Summer Capacity, and
Total Capacity = Sum of [NSC] of units for the respective prime mover and energy source categories.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 5.5. Planned Transmission Capacity Additions, by High-Voltage Size, 2009 through 2015
(Circuit Miles of Transmission)

Voltage		Circuit Miles						
Type	**Operating (kV)**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
AC	230	1,028	1,523	958	1,308	991	365	478
AC	345	276	1,039	877	519	4,069	1,005	1,017
AC	500	32	296	574	1,013	2,181	4,281	1,917
AC	765	--	--	--	--	285	--	--
AC Total		**1,336**	**2,858**	**2,409**	**2,839**	**7,525**	**5,651**	**3,412**
DC	100-299	--	--	--	--	1	--	--
DC	300-399	--	--	--	--	--	--	--
DC	400-599	--	--	--	--	--	--	1,300
DC Total		**--**	**--**	**--**	**--**	**1**	**--**	**1,300**
Grand Total		**1,336**	**2,858**	**2,409**	**2,839**	**7,526**	**5,651**	**4,712**
Lines taken out of service		**5**	**265**	**--**	**--**	**311**	**45**	**116**

Notes: • Circuit miles do not equal physical miles on the ground; the reference terminology for that concept is structural mile. • More than one circuit can be present on a structure. • Some structures were designed and then built to carry future transmission circuits in order to handle expected growth in new capability requirements. • Lines are taken out of service for a variety of reasons including intentional changes to the right-of-way to better use available land for different levels of voltage and types of poles and towers.

Source: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Chapter 6. Trade

Table 6.1. Electric Power Industry - Electricity Purchases, 1997 through 2008
(Thousand Megawatthours)

	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
U.S. Total	**5,612,781**	**5,411,422[R]**	**5,502,584**	**6,092,285**	**6,998,549**	**6,979,669**	**8,754,807**	**7,555,276**	**2,345,540**	**2,039,969**	**2,020,622**	**1,966,447**
Electric Utilities	2,483,927	2,504,002	2,605,315	2,760,043	2,725,694	2,610,525	2,620,712	3,045,854	2,250,382	1,949,574	1,927,198	1,878,099
Energy-Only Providers	3,024,730	2,805,833[R]	2,793,288	3,250,298	4,170,331	4,264,102	6,050,159	4,412,064	NA	NA	NA	NA
IPP	25,431	24,942	26,628	12,201	24,258	37,921	15,801	97,357[1]	10,622	4,358	4,089	1,647
CHP	78,693	76,646	77,353	69,744	78,267	67,122	68,135	NA	84,536	86,037	89,334	86,701

[1] For 2001, CHP purchases are combined with IPP data above.

NA = Not available.

R = Revised.

Notes: • Energy-only providers are wholesale and retail power marketers. • IPP are independent power producers and CHP are combined heat and power producers. • Totals may not equal sum of components because of independent rounding. • The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001 and after 2001 should be done with caution.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." For unregulated entities prior to 2001. Form EIA-860B, "Annual Electric Generator Report - Nonutility," and predecessor forms; and Form EIA-923, "Power Plant Operations Report" for 2007 and predecessor form(s) for earlier years.

Table 6.2. Electric Power Industry - Electricity Sales for Resale, 1997 through 2008
(Thousand Megawatthours)

	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
U.S. Total	**5,680,733**	**5,479,394**	**5,493,473**	**6,071,659**	**6,758,975**	**6,920,954**	**8,568,678**	**7,345,319**	**2,355,154**	**1,998,090**	**1,921,858**	**1,838,539**
Electric Utilities	1,576,976	1,603,179	1,698,389	1,925,710	1,923,440	1,824,030	1,838,901	2,146,689	1,715,582	1,635,614	1,664,081	1,616,318
Energy-Only Providers	2,718,661	2,476,740	2,446,104	2,867,048	3,756,175	3,906,220	5,757,283	4,386,632	NA	NA	NA	NA
IPP	1,355,017	1,368,310	1,321,342	1,252,796	1,053,364	1,156,796	943,531	811,998[1]	611,150	335,122	228,617	192,299
CHP	30,079	31,165	27,638	26,105	25,996	33,909	28,963	NA	28,421	27,354	29,160	29,922

[1] For 2001, CHP sales are combined with IPP data above.

NA = Not available.

Notes: • Energy-only providers are wholesale and retail power marketers. • IPP are independent power producers and CHP are combined heat and power producers. • The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001, and after 2001 should be done with caution. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." For unregulated entities prior to 2001. Form EIA-860B, "Annual Electric Generator Report - Nonutility," and predecessor forms; and Form EIA-923, "Power Plant Operations Report" for 2007 and predecessor form(s) for earlier years.

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1997 through 2008
(Megawatthours)

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Electricity Imports and Exports												
Canada												
Imports	55,732,401	50,118,056	41,544,052	42,930,224	33,007,487	29,324,625	36,536,479	38,401,598	48,515,476	42,911,308	39,502,108	43,008,501
Exports	23,499,444	19,559,417	23,405,387	19,320,280	22,482,109	23,584,513	15,231,079	16,105,612	12,684,706	12,953,488	11,683,276	7,470,332
Mexico												
Imports[1]	1,288,152	1,277,644	1,147,258	1,597,275	1,202,576	1,069,926	242,596	98,649	76,800	303,439	11,249	22,729
Exports	584,001	584,176	865,948	470,731	415,754	390,190	564,603	367,680	2,144,676	1,268,284	1,973,203	1,503,707
Total Imports	**57,020,553**	**51,395,702**	**42,691,310**	**44,527,499**	**34,210,063**	**30,394,551**	**36,779,077**	**38,500,247**	**48,592,276**	**43,214,747**	**39,513,357**	**43,031,230**
Total Exports	**24,083,445**	**20,143,592**	**24,271,335**	**19,791,011**	**22,897,863**	**23,974,703**	**15,795,681**	**16,473,292**	**14,829,382**	**14,221,772**	**13,656,479**	**8,974,039**

[1] Includes contract terminations in 1997 and 2000.

Note: Totals may not equal sum of components because of independent rounding.

Sources: DOE, Office of Electricity Delivery and Energy Reliability, Form OE-781R, " Annual Report of International Electric Export/Import Data," predecessor forms, and National Energy Board of Canada. For 2001 forward, data from the California Independent System Operator are used in combination with the Form OE-781R values to estimate electricity trade with Mexico. In 2008, the California - ISO reported electriciy purchases on 1,189,504 MWh and 216,321 MWh sales with Mexico.

Chapter 7. Retail Customers, Sales, and Revenue

Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1997 through 2008
(Number)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1997	107,065,589	13,542,374	563,223	NA	951,863	122,123,049
1998	109,048,343	13,887,066	539,903	NA	932,838	124,408,150
1999	110,383,238	14,073,764	552,690	NA	935,311	125,945,003
2000	111,717,711	14,349,067	526,554	NA	974,185	127,567,517
2001	114,890,240	14,867,490	571,463	NA	1,030,046	131,359,239
2002	116,622,037	15,333,700	601,744	NA	1,066,554	133,624,035
2003	117,280,481	16,549,519	713,221	1,127	NA	134,544,348
2004	118,763,768	16,606,783	747,600	1,025	NA	136,119,176
2005	120,760,839	16,871,940	733,862	518	NA	138,367,159
2006	122,471,071	17,172,499	759,604	791	NA	140,403,965
2007	123,949,916	17,377,219	793,767	750	NA	142,121,652
2008	124,937,469	17,562,726	774,713	727	NA	143,275,635
Full-Service Providers[1]						
1997	107,033,338	13,540,374	562,972	NA	951,863	122,088,547
1998	108,736,845	13,832,662	538,167	NA	932,838	124,040,512
1999	109,817,057	13,963,937	527,329	NA	934,260	125,242,583
2000	110,505,820	14,058,271	512,551	NA	953,756	126,030,398
2001	112,472,629	14,364,578	553,280	NA	1,004,027	128,394,514
2002	113,790,812	14,899,747	586,217	NA	1,035,604	130,312,380
2003	115,029,545	16,136,616	695,616	1,042	NA	131,862,819
2004	116,325,747	16,161,269	733,809	941	NA	133,221,766
2005	118,469,928	16,389,549	719,219	496	NA	135,579,192
2006	120,677,627	16,673,766	745,645	764	NA	138,097,802
2007	121,782,003	16,767,635	771,637	710	NA	139,321,985
2008	122,595,644	16,952,660	756,294	664	NA	140,305,262
Energy-Only Providers						
1997	32,251	2,000	251	NA	0	34,502
1998	311,498	54,404	1,736	NA	0	367,638
1999	566,181	109,827	25,361	NA	1,051	702,420
2000	1,211,891	290,796	14,003	NA	20,429	1,537,119
2001	2,417,611	502,912	18,183	NA	26,019	2,964,725
2002	2,831,225	433,953	15,527	NA	30,950	3,311,655
2003	2,250,936	412,903	17,605	85	NA	2,681,529
2004	2,438,021	445,514	13,791	84	NA	2,897,410
2005	2,290,911	482,391	14,643	22	NA	2,787,967
2006	1,793,444	498,733	13,959	27	NA	2,306,163
2007	2,167,913	609,584	22,130	40	NA	2,799,667
2008	2,341,825	610,066	18,419	63	NA	2,970,373

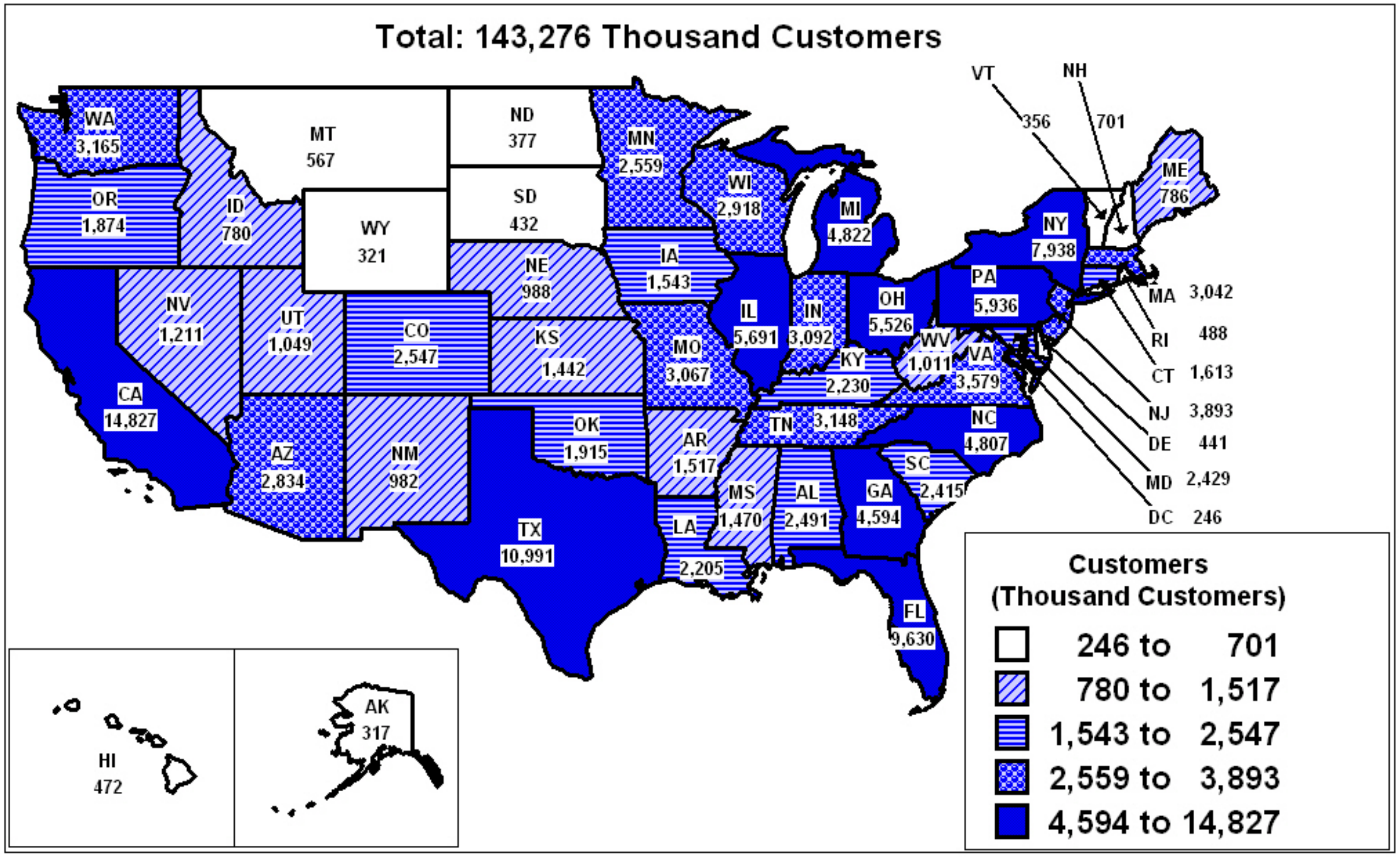
[1] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers."

NA = Not available.

Notes: • See Technical Notes reference for definitions. • Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.1. U.S. Electric Industry Total Ultimate Customers by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

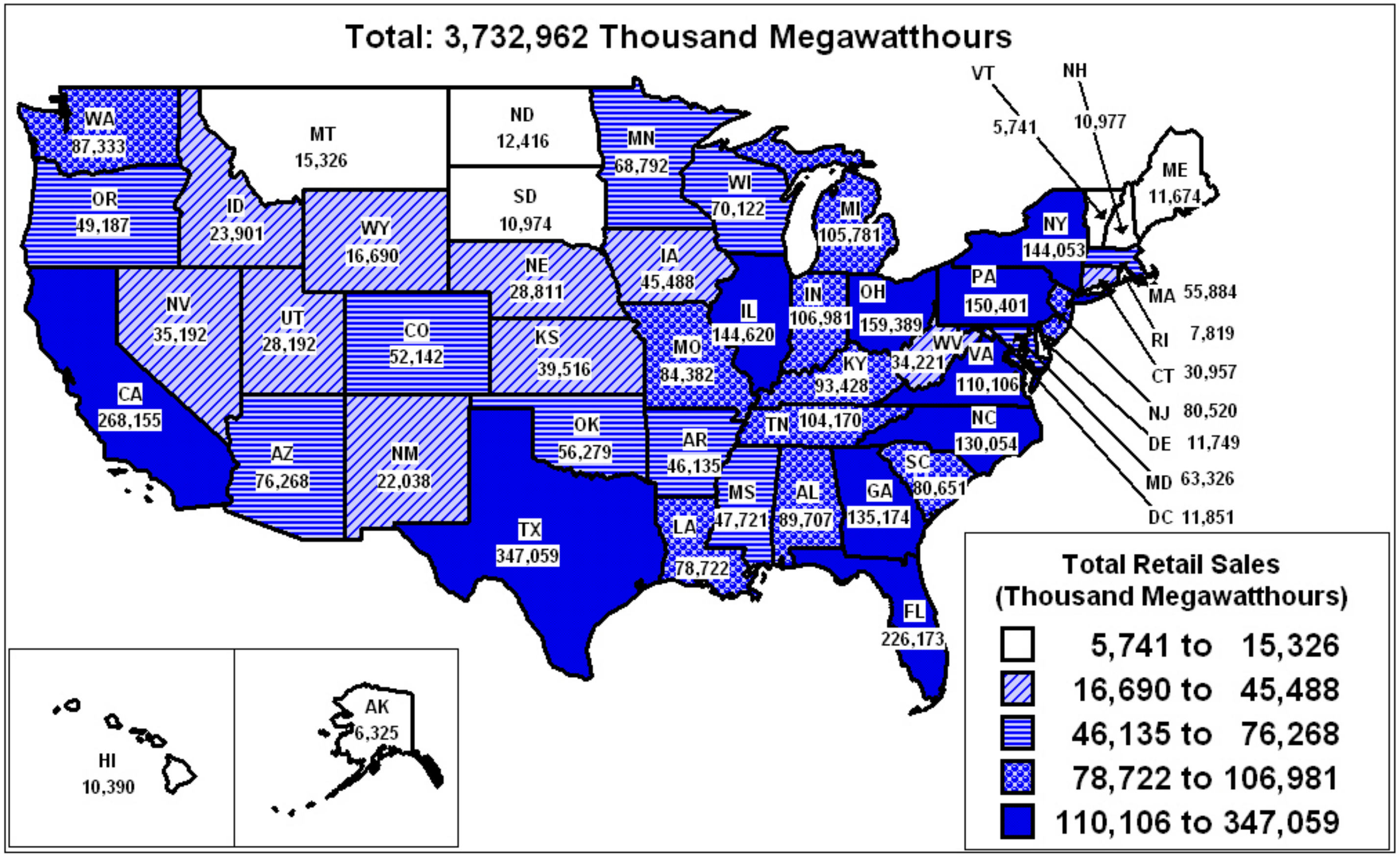
Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 7.2. Retail Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 1997 through 2008
(Megawatthours)

Period	Sales						Direct Use[1]	Total End Use
	Residential	Commercial	Industrial	Trans-portation	Other	Total		
Total Electric Industry								
1997	1,075,880,098	928,632,774	1,038,196,892	NA	102,900,664	3,145,610,428	156,238,898	3,301,849,326
1998	1,130,109,120	979,400,928	1,051,203,115	NA	103,517,589	3,264,230,752	160,865,884	3,425,096,636
1999	1,144,923,069	1,001,995,720	1,058,216,608	NA	106,951,684	3,312,087,081	171,629,285	3,483,716,366
2000	1,192,446,491	1,055,232,090	1,064,239,393	NA	109,496,292	3,421,414,266	170,942,509	3,592,356,775
2001	1,201,606,593	1,083,068,516	996,609,310	NA	113,173,685	3,394,458,104	162,648,615	3,557,106,719
2002	1,265,179,869	1,104,496,607	990,237,631	NA	105,551,904	3,465,466,011	166,184,296	3,631,650,307
2003	1,275,823,910	1,198,727,601	1,012,373,247	6,809,728	NA	3,493,734,486	168,294,526	3,662,029,012
2004	1,291,981,578	1,230,424,731	1,017,849,532	7,223,642	NA	3,547,479,483	168,470,002	3,715,949,485
2005	1,359,227,107	1,275,079,020	1,019,156,065	7,506,321	NA	3,660,968,513	150,015,531	3,810,984,044
2006	1,351,520,036	1,299,743,695	1,011,297,566	7,357,543	NA	3,669,918,840	146,926,612	3,816,845,452
2007	1,392,240,996	1,336,315,196	1,027,831,925	8,172,595	NA	3,764,560,712	159,253,522	3,923,814,234
2008	1,379,981,104	1,335,981,135	1,009,300,309	7,699,632	NA	3,732,962,180	173,481,228	3,906,443,408
Full-Service Providers[2]								
1997	1,075,766,590	928,440,265	1,032,653,445	NA	102,900,664	3,139,760,964	NA	3,139,760,964
1998	1,127,734,988	968,528,009	1,040,037,873	NA	103,517,589	3,239,818,459	NA	3,239,818,459
1999	1,140,761,016	970,600,943	1,017,783,037	NA	106,754,043	3,235,899,039	NA	3,235,899,039
2000	1,183,137,429	1,000,865,367	1,017,722,945	NA	107,824,323	3,309,550,064	NA	3,309,550,064
2001	1,188,219,590	1,037,998,484	961,812,417	NA	108,632,086	3,296,662,577	NA	3,296,662,577
2002	1,248,349,458	1,036,366,268	937,138,192	NA	102,238,786	3,324,092,704	NA	3,324,092,704
2003	1,257,766,998	1,112,206,121	931,661,404	3,315,043	NA	3,304,949,566	NA	3,304,949,566
2004	1,272,237,425	1,116,497,417	933,529,502	3,188,466	NA	3,325,452,810	NA	3,325,452,810
2005	1,339,568,275	1,151,327,861	929,675,932	3,341,814	NA	3,423,913,882	NA	3,423,913,882
2006	1,337,837,993	1,170,661,399	939,194,648	3,040,062	NA	3,450,734,102	NA	3,450,734,102
2007	1,375,450,126	1,180,789,042	923,148,031	2,635,498	NA	3,482,022,697	NA	3,482,022,697
2008	1,362,811,730	1,152,674,093	929,246,647	2,515,304	NA	3,447,247,774	NA	3,447,247,774
Energy-Only Providers								
1997	113,508	192,509	5,543,447	NA	0	5,849,464	NA	5,849,464
1998	2,374,132	10,872,919	11,165,242	NA	0	24,412,293	NA	24,412,293
1999	4,162,053	31,394,777	40,433,571	NA	197,641	76,188,042	NA	76,188,042
2000	9,309,062	54,366,723	46,516,448	NA	1,671,969	111,864,202	NA	111,864,202
2001	13,387,003	45,070,032	34,796,893	NA	4,541,599	97,795,527	NA	97,795,527
2002	16,830,411	68,130,339	53,099,439	NA	3,313,118	141,373,307	NA	141,373,307
2003	18,056,912	86,521,480	80,711,843	3,494,685	NA	188,784,920	NA	188,784,920
2004	19,744,153	113,927,314	84,320,030	4,035,176	NA	222,026,673	NA	222,026,673
2005	19,658,832	123,751,159	89,480,133	4,164,507	NA	237,054,631	NA	237,054,631
2006	13,682,043	129,082,296	72,102,918	4,317,481	NA	219,184,738	NA	219,184,738
2007	16,790,870	155,526,154	104,683,894	5,537,097	NA	282,538,015	NA	282,538,015
2008	17,169,374	183,307,042	80,053,662	5,184,328	NA	285,714,406	NA	285,714,406

[1] Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.
[2] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so are included under "Full-Service Providers."
NA = Not available.
Notes: • See Technical Notes reference for definitions. • Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.
Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report;" Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Form EIA-906, "Power Plant Report;" Form EIA-920, "Combined Heat and Power Plant Report."

Figure 7.2. U.S. Electric Industry Total Retail Sales by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 7.3. Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1997 through 2008
(Million Dollars)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry[1]						
1997	90,704	70,497	47,023	NA	7,110	215,334
1998	93,360	72,575	47,050	NA	6,863	219,848
1999	93,483	72,771	46,846	NA	6,796	219,896
2000	98,209	78,405	49,369	NA	7,179	233,163
2001	103,158	85,741	50,293	NA	8,151	247,343
2002	106,834	87,117	48,336	NA	7,124	249,411
2003	111,249	96,263	51,741	514	NA	259,767
2004	115,577	100,546	53,477	519	NA	270,119
2005	128,393	110,522	58,445	643	NA	298,003
2006	140,582	122,914	62,308	702	NA	326,506
2007	148,295	128,903	65,712	792	NA	343,703
2008	155,433	138,469	68,920	827	NA	363,650
Full-Service Providers[2]						
1997	90,694	70,482	46,772	NA	7,110	215,059
1998	93,164	71,769	46,550	NA	6,863	218,346
1999	93,142	70,492	45,056	NA	6,783	215,473
2000	97,086	73,704	46,465	NA	6,988	224,243
2001	101,541	81,385	48,182	NA	7,766	238,874
2002	104,814	80,573	44,826	NA	6,803	237,014
2003	109,165	87,764	46,686	226	NA	243,841
2004	113,306	89,597	47,993	238	NA	251,134
2005	125,983	97,405	52,113	249	NA	275,749
2006	138,608	107,432	56,385	257	NA	302,683
2007	145,642	109,703	56,950	232	NA	312,527
2008	152,429	115,062	61,286	250	NA	329,027
Restructured Retail Service Providers[3]						
1997	10	15	251	NA	NA	275
1998	196	806	500	NA	NA	1,502
1999	340	2,279	1,791	NA	13	4,423
2000	1,123	4,702	2,904	NA	191	8,920
2001	1,617	4,356	2,111	NA	385	8,469
2002	2,020	6,545	3,510	NA	321	12,396
2003	2,084	8,499	5,055	288	NA	15,926
2004	2,272	10,949	5,484	281	NA	18,985
2005	2,410	13,117	6,333	394	NA	22,254
2006	1,974	15,482	5,922	445	NA	23,823
2007	2,653	19,200	8,762	560	NA	31,176
2008	3,004	23,407	7,635	577	NA	34,622
Energy-Only Providers[4]						
1997	10	15	251	NA	0	275
1998	196	806	500	NA	0	1,502
1999	340	2,279	1,791	NA	13	4,423
2000	530	3,175	2,374	NA	75	6,153
2001	714	2,806	1,632	NA	237	5,390
2002	914	3,989	2,408	NA	143	7,454
2003	980	5,210	3,605	215	NA	10,011
2004	1,086	6,859	3,881	201	NA	12,027
2005	1,285	8,844	4,749	308	NA	15,186
2006	1,127	10,792	4,510	356	NA	16,784
2007	1,646	13,553	7,197	458	NA	22,854
2008	1,873	17,126	6,212	455	NA	25,667
Delivery-Only Service						
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	593	1,527	531	NA	116	2,767
2001	903	1,551	479	NA	147	3,080
2002	1,106	2,556	1,102	NA	178	4,942
2003	1,104	3,289	1,450	72	NA	5,915
2004	1,186	4,090	1,603	79	NA	6,958
2005	1,125	4,273	1,584	86	NA	7,068
2006	847	4,690	1,412	90	NA	7,040
2007	1,007	5,647	1,565	102	NA	8,322
2008	1,131	6,281	1,422	121	NA	8,956

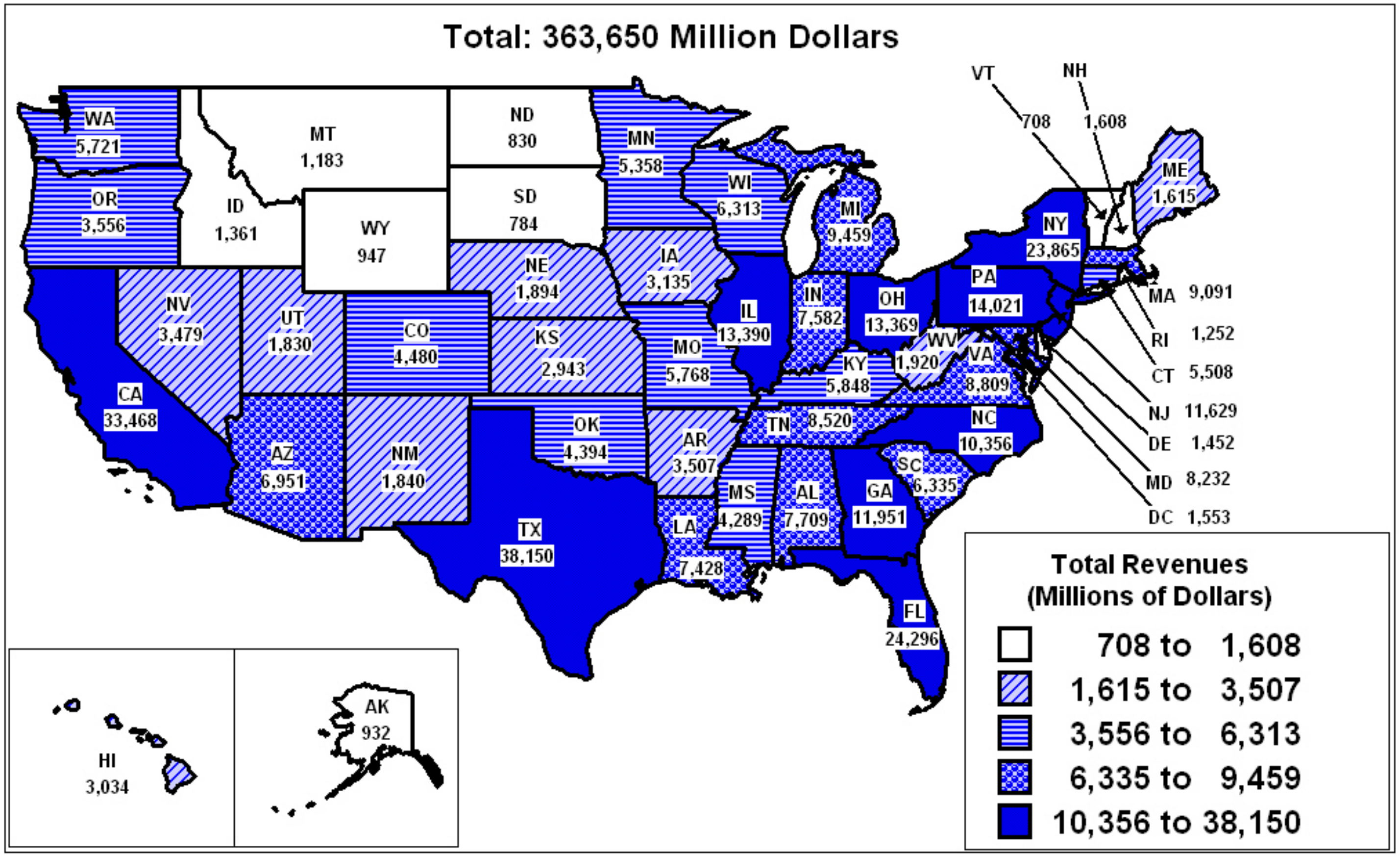
[1] Sum of Full-Service Providers and Restructured Retail Service Providers.
[2] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so are included under "Full-Service Providers."
[3] Sum of Energy-Only Providers and Delivery-Only Service.
[4] From 1996 to 1999, revenue was estimated based on retail sales reported on the Form EIA-861.

NA = Not available.

Notes: • See Technical Notes reference for definitions. • Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Restructured Retail Service Providers represent the sum of Energy-Only and Delivery-Only Services. • For historical data, see the State of California discussion in Technical Notes. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.3.   U.S. Electric Industry Total Revenues by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 7.4. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, 1997 through 2008
(Cents per kilowatthour)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry[1]						
1997	8.43	7.59	4.53	NA	6.91	6.85
1998	8.26	7.41	4.48	NA	6.63	6.74
1999	8.16	7.26	4.43	NA	6.35	6.64
2000	8.24	7.43	4.64	NA	6.56	6.81
2001	8.58	7.92	5.05	NA	7.20	7.29
2002	8.44	7.89	4.88	NA	6.75	7.20
2003	8.72	8.03	5.11	7.54	NA	7.44
2004	8.95	8.17	5.25	7.18	NA	7.61
2005	9.45	8.67	5.73	8.57	NA	8.14
2006	10.40	9.46	6.16	9.54	NA	8.90
2007	10.65	9.65	6.39	9.70	NA	9.13
2008	11.26	10.36	6.83	10.74	NA	9.74
Full-Service Providers[2]						
1997	8.43	7.59	4.53	NA	6.91	6.85
1998	8.26	7.41	4.48	NA	6.63	6.74
1999	8.16	7.26	4.43	NA	6.35	6.66
2000	8.21	7.36	4.57	NA	6.48	6.78
2001	8.55	7.84	5.01	NA	7.15	7.25
2002	8.40	7.77	4.78	NA	6.65	7.13
2003	8.68	7.89	5.01	6.82	NA	7.38
2004	8.91	8.02	5.14	7.47	NA	7.55
2005	9.40	8.46	5.61	7.45	NA	8.05
2006	10.36	9.18	6.00	8.44	NA	8.77
2007	10.59	9.29	6.17	8.82	NA	8.98
2008	11.18	9.98	6.60	9.96	NA	9.54
Restructured Retail Service Providers[3]						
1997	8.43	7.59	4.53	NA	NA	4.71
1998	8.26	7.41	4.48	NA	NA	6.15
1999	8.17	7.26	4.43	NA	6.45	5.81
2000	12.07	8.65	6.24	NA	11.42	7.97
2001	12.08	9.67	6.07	NA	8.47	8.66
2002	12.00	9.61	6.61	NA	9.69	8.77
2003	11.54	9.82	6.26	8.23	NA	8.44
2004	11.51	9.61	6.50	6.95	NA	8.55
2005	12.26	10.60	7.08	9.47	NA	9.39
2006	14.43	11.99	8.21	10.32	NA	10.87
2007	15.80	12.35	8.37	10.11	NA	11.03
2008	17.49	12.77	9.54	11.12	NA	12.12
Energy-Only Providers[4]						
1997	8.43	7.59	4.53	NA	--	4.71
1998	8.26	7.41	4.48	NA	--	6.15
1999	8.17	7.26	4.43	NA	6.45	5.81
2000	5.69	5.84	5.10	NA	4.47	5.50
2001	5.34	6.22	4.69	NA	5.23	5.51
2002	5.43	5.86	4.53	NA	4.30	5.27
2003	5.43	6.02	4.47	6.16	NA	5.30
2004	5.50	6.02	4.60	4.99	NA	5.42
2005	6.54	7.15	5.31	7.40	NA	6.41
2006	8.23	8.36	6.25	8.24	NA	7.66
2007	9.80	8.71	6.87	8.28	NA	8.09
2008	10.91	9.34	7.76	8.79	NA	8.98
Delivery-Only Service						
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	6.37	2.81	1.14	--	6.95	2.47
2001	6.74	3.44	1.38	--	3.24	3.15
2002	6.57	3.75	2.08	--	5.39	3.50
2003	6.11	3.80	1.80	2.07	--	3.13
2004	6.00	3.59	1.90	1.96	NA	3.13
2005	5.72	3.45	1.77	2.07	NA	2.98
2006	6.19	3.63	1.96	2.08	NA	3.21
2007	6.00	3.63	1.50	1.84	NA	2.95
2008	6.59	3.43	1.78	2.34	NA	3.13

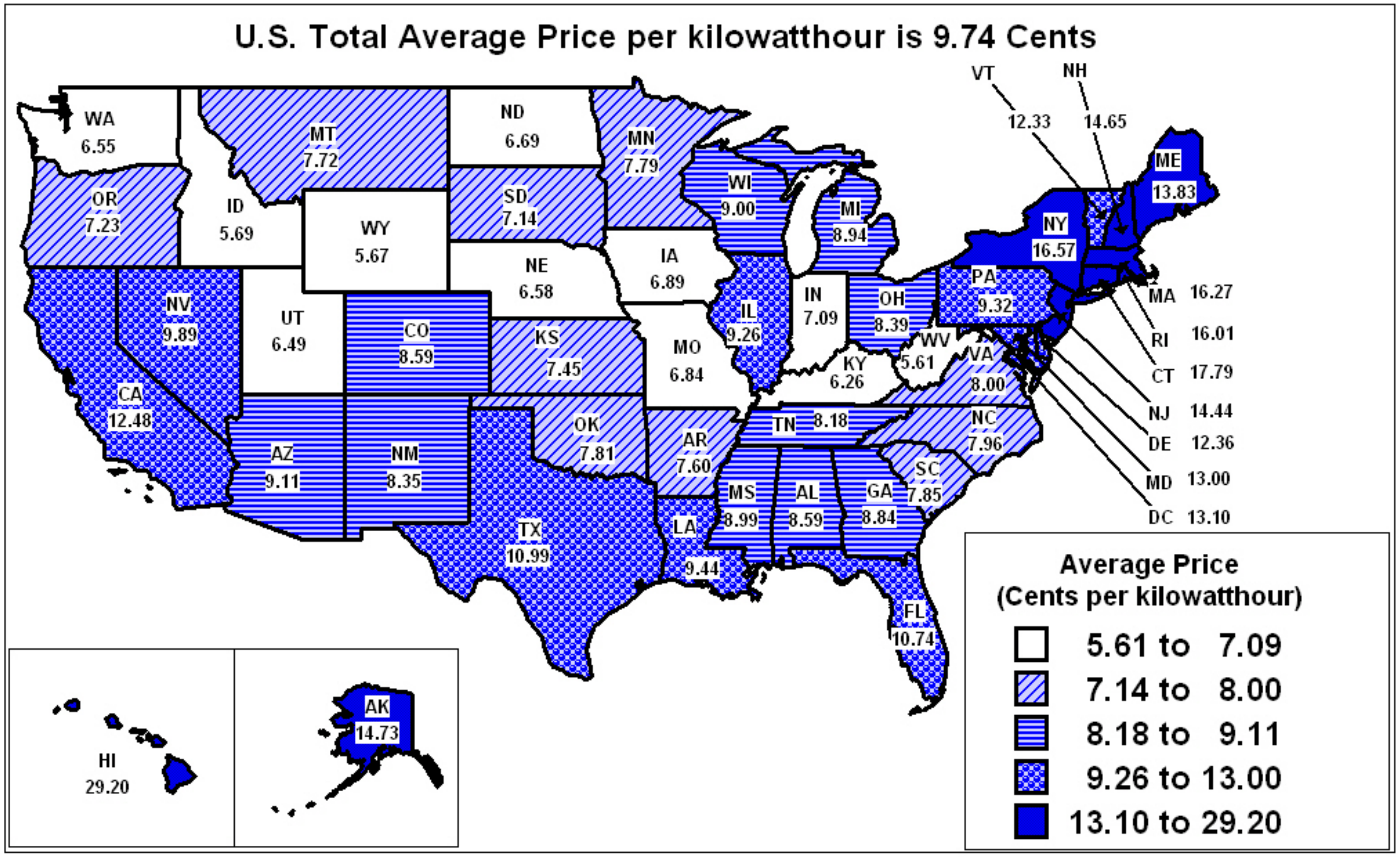
[1] Weighted average of Full-Service Providers and Restructured Retail Service Providers.
[2] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so are included under "Full-Service Providers."
[3] Sum of Energy-Only Providers and Delivery-Only Service.
[4] From 1996 to 1999, average revenue was estimated based on retail sales reported on the Form EIA-861.

NA = Not available.

Notes: • See Glossary reference for definitions • Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Restructured Retail Service Providers represent the sum of Energy-Only and Delivery-Only Services.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

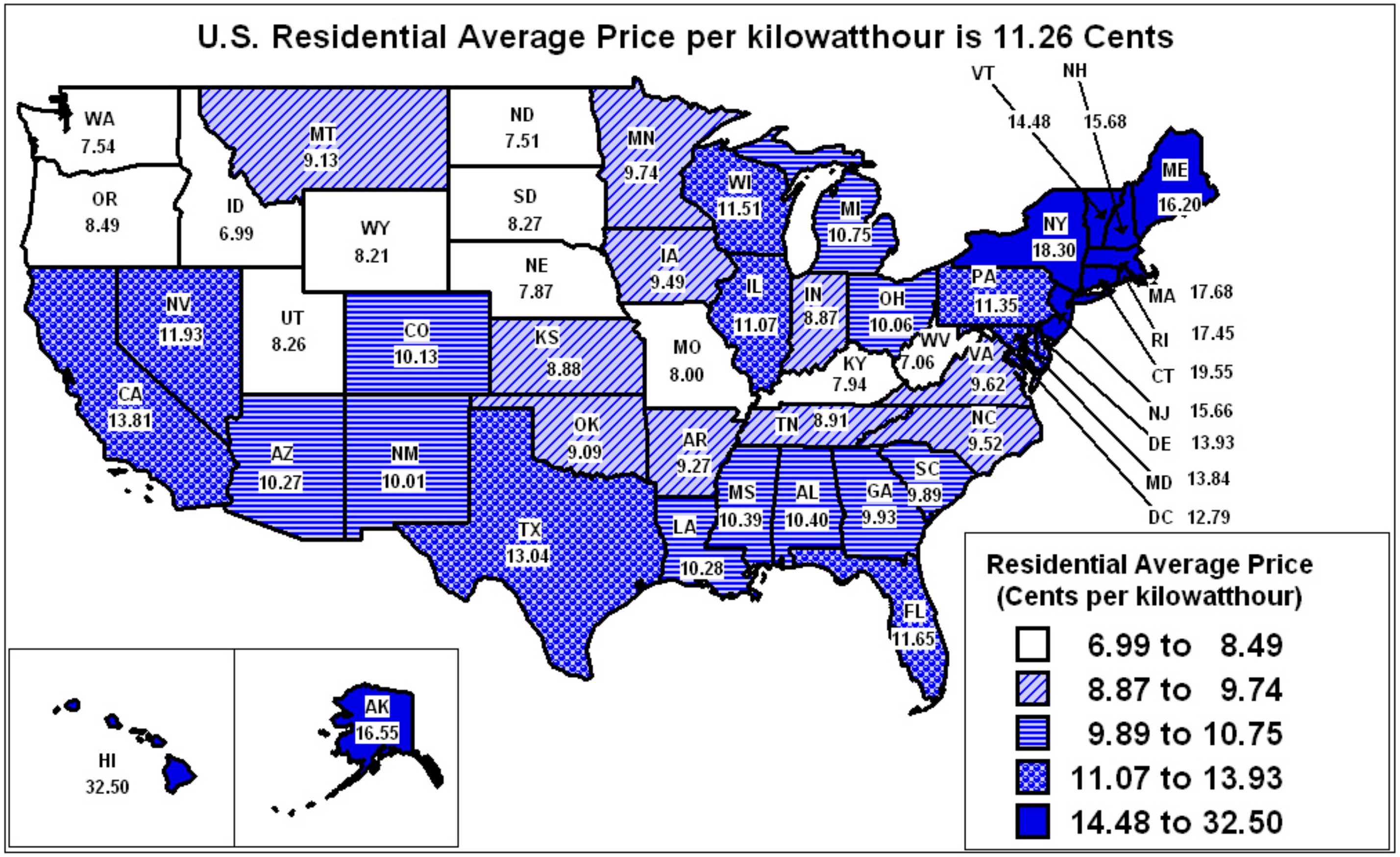
Figure 7.4. Average Retail Price of Electricity by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

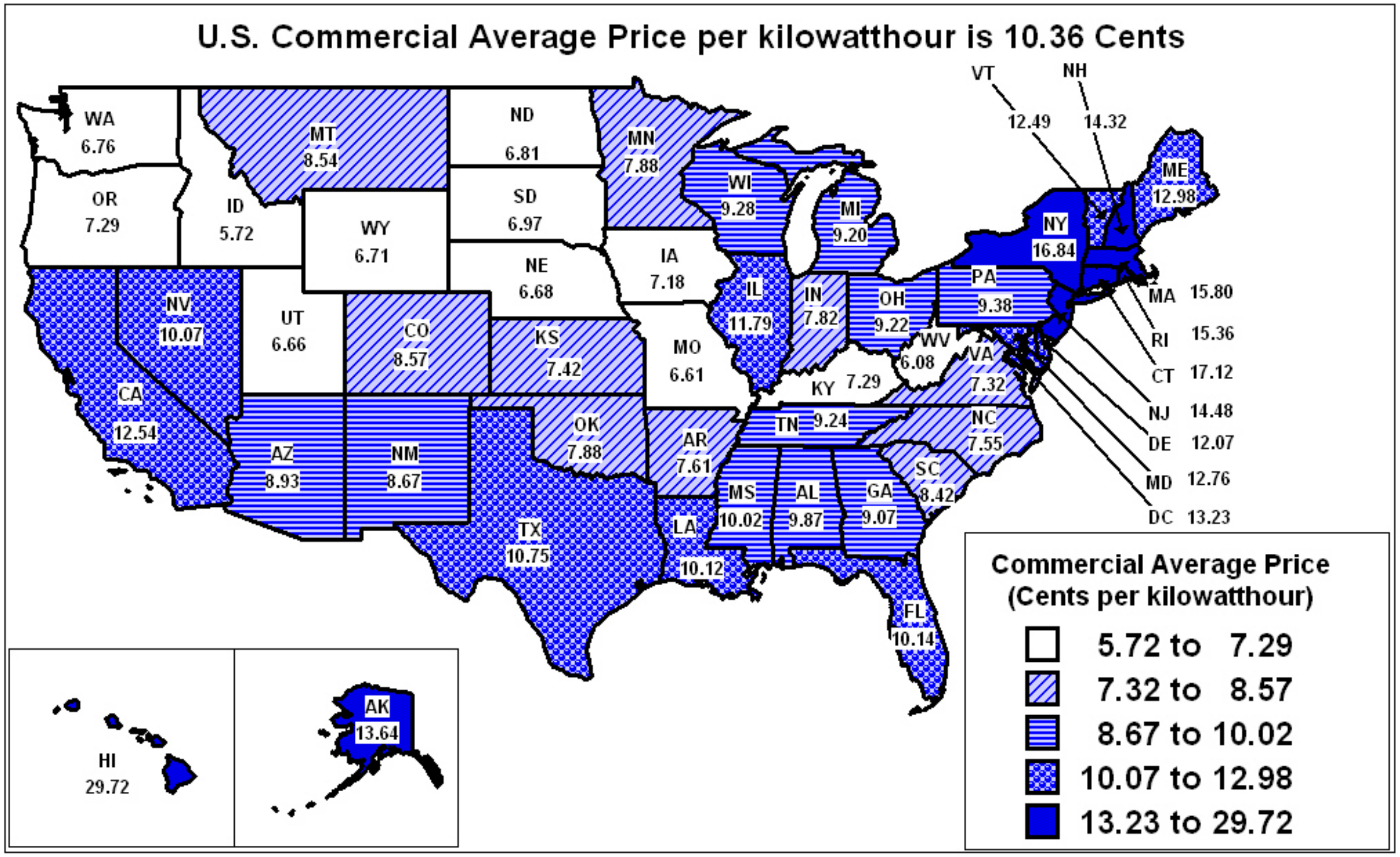
Figure 7.5. Average Residential Price of Electricity by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

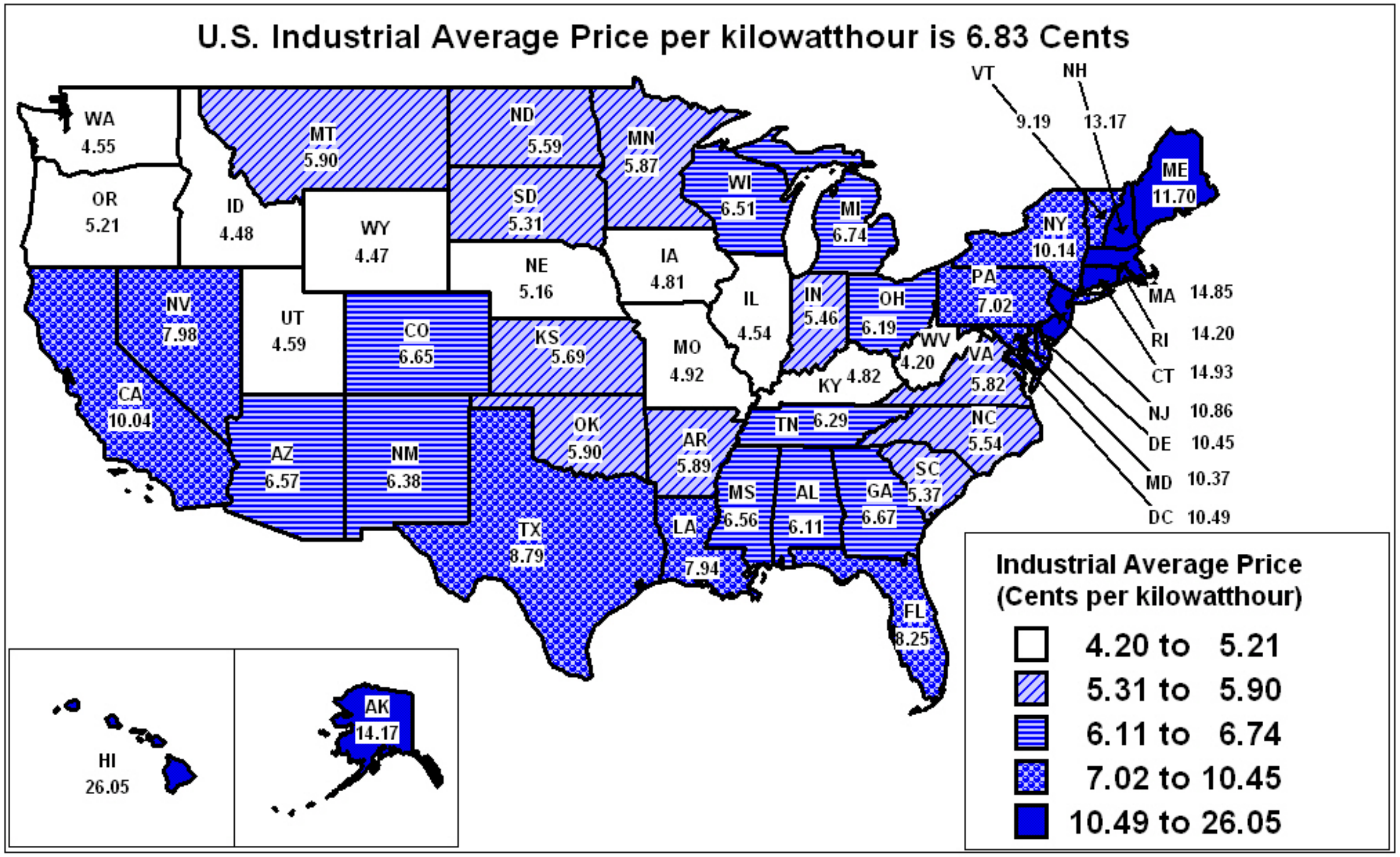
Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.6. Average Commercial Price of Electricity by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.7. Average Industrial Price of Electricity by State, 2008



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 7.5. Net Metering and Green Pricing Customers by End Use Sector, 2002 - 2008

Year	Green Pricing			Net Metering		
	Residential	Non Residential	Total	Residential	Non Residential	Total
2002............	688,069	23,481	711,550	3,559	913	4,472
2003............	819,579	57,547	877,126	5,870	943	6,813
2004............	864,794	63,539	928,333	14,114	1,712	15,826
2005............	871,774	70,998	942,772	19,244	1,902	21,146
2006[1]	606,919	35,937	642,856	30,689	2,930	33,619
2007............	773,391	62,260	835,651	44,886	3,943	48,829[R]
2008............	918,284	64,711	982,995	64,400	5,609	70,009

[1] In 2006 the single largest provider of green pricing services in the country discontinued service in two States. More than 297,600 customers in green pricing programs reverted to standard service tariffs, predominantly in Ohio and Pennsylvania.

R = Revised.

Notes: • Green Pricing programs allow electricity customers the opportunity to purchase electricity generated from renewable resources, thereby encouraging renewable energy development. Renewable resources include solar, wind, geothermal, hydroelectric power, and wood. • Net Metering arrangements permit facilities and residences (using a meter that reads inflows and outflows of electricity) to sell any excess power generated over its load requirement back to the distributor to offset consumption.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Chapter 8. Revenue and Expense Statistics

Table 8.1. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1997 through 2008
(Million Dollars)

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Utility Operating Revenues	**298,962**	**278,499**	**275,501**	**265,652**	**238,759**	**230,151**	**219,609**	**267,276**	**233,915**	**213,090**	**214,849**	**209,022**
Electric Utility	266,124	248,278	246,736	234,909	213,012	206,268	200,360	243,982	213,634	197,010	199,643	191,323
Other Utility	32,838	30,221	28,765	30,743	25,747	23,883	19,250	23,294	20,281	16,081	15,206	17,700
Utility Operating Expenses	**267,263**	**248,039**	**245,589**	**236,786**	**206,960**	**201,057**	**189,062**	**234,910**	**210,250**	**180,467**	**183,954**	**177,798**
Electric Utility	236,572	219,796	218,445	207,830	183,121	179,044	171,604	213,458	191,564	165,942	170,162	161,780
Operation	175,887	158,971	158,893	150,645	131,560	125,436	116,660	161,233	132,607	107,686	109,317	101,999
Production	140,974	126,096	127,494	120,586	103,871	98,305	90,715	135,791	107,554	82,791	84,741	78,429
Cost of Fuel	47,337	41,263	37,945	36,106	28,544	26,871	24,149	29,434	32,407	29,605	30,945	31,340
Purchased Power	84,724	76,515	79,205	77,902	67,126	63,749	58,810	98,020	62,608	42,663	41,789	37,014
Other	8,937	8,337	10,371	6,599	8,226	7,709	7,776	8,359	12,561	10,551	12,036	10,108
Transmission	6,950	6,102	6,179	5,664	4,531	3,653	3,560	3,385	2,713	2,480	2,177	1,834
Distribution	3,997	3,824	3,640	3,502	3,287	3,214	3,117	3,208	3,092	2,959	2,759	2,641
Customer Accounts	5,286	4,787	4,409	4,229	4,077	4,262	4,168	4,432	4,239	4,190	3,964	3,682
Customer Service	3,567	2,953	2,536	2,291	2,013	1,902	1,820	1,855	1,826	1,854	1,937	1,886
Sales	225	245	240	219	237	238	264	282	405	474	510	494
Administrative and General	14,718	14,772	14,580	14,130	13,537	13,863	13,018	12,292	12,768	12,950	13,204	13,034
Maintenance	14,192	13,538	12,838	12,033	11,743	11,340	10,861	11,154	12,064	12,359	12,356	12,093
Depreciation	19,049	18,480	17,373	17,123	16,322	15,981	16,199	17,476	20,636	20,232	21,287	20,858
Taxes and Other	26,202	27,641	28,149	26,805	22,190	25,027	26,716	21,765	24,479	23,786	25,695	26,019
Other Utility	30,692	28,243	27,143	28,956	23,839	22,013	17,457	21,452	18,686	14,525	13,791	16,018
Net Utility Operating Income	**31,699**	**30,460**	**29,912**	**28,866**	**31,799**	**29,094**	**30,548**	**32,366**	**23,665**	**32,623**	**30,896**	**31,225**

Notes: • Data for the years 1997 - 2007 were updated reflecting revisions reported by Energy Velocity. • 2007 financial data does not include information on Entergy Gulf State Louisiana LLC and Entergy Texas Inc. as both were not reported on the FERC Form for that year. • Missing or erroneous respondent data may result in slight imbalances in some of the expense account subtotals. Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others."

Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1997 through 2008
(Mills per Kilowatthour)

Plant Type	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Operation												
Nuclear	9.68	9.21	8.95	8.63	8.30	8.86	8.54	8.30	8.43	8.95	9.98	10.83
Fossil Steam	3.65	3.49	3.24	2.97	2.97	2.50	2.59	2.41	2.26	2.24	2.17	2.22
Hydroelectric[1]	5.78	5.44	3.76	3.95	3.95	3.47	3.71	4.27	3.52	3.35	3.09	2.65
Gas Turbine and Small Scale[2]	2.98	2.89	2.99	3.00	3.00	2.76	2.72	3.15	4.08	4.93	3.81	4.36
Maintenance												
Nuclear	6.20	5.79	5.69	5.27	5.27	5.23	5.04	5.02	4.96	5.01	5.77	6.73
Fossil Steam	3.59	3.37	3.19	2.98	2.98	2.72	2.67	2.61	2.42	2.46	2.41	2.42
Hydroelectric[1]	3.89	3.87	2.70	2.73	2.73	2.32	2.62	2.89	2.22	2.03	1.58	1.98
Gas Turbine and Small Scale[2]	2.72	2.42	2.16	1.89	1.89	2.26	2.38	3.33	3.26	4.78	3.42	3.33
Fuel												
Nuclear	5.29	4.99	4.85	4.63	4.63	4.60	4.60	4.67	4.90	5.16	5.39	5.41
Fossil Steam	28.43	23.88	23.09	21.69	21.69	17.29	16.09	18.15	17.73	15.50	15.86	16.73
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small Scale[2]	64.23	58.75	53.89	55.52	55.52	43.89	31.84	43.55	41.76	27.95	22.85	24.71
Total												
Nuclear	21.16	20.00	19.49	18.53	18.53	18.69	18.18	17.99	18.29	19.12	21.13	22.96
Fossil Steam	35.67	30.74	29.52	27.64	27.64	22.51	21.36	23.17	22.41	20.20	20.43	21.38
Hydroelectric[1]	9.67	9.32	6.46	6.68	6.68	5.79	6.33	7.16	5.74	5.38	4.67	4.64
Gas Turbine and Small Scale[2]	69.93	64.06	59.04	60.41	60.41	48.91	36.94	50.03	49.09	37.66	30.08	32.41

[1] Conventional hydro and pumped storage.
[2] Gas turbine, internal combustion, photovoltaic, and wind plants.

Notes: • Data for the years 1997 - 2007 were updated reflecting revisions reported by Energy Velocity. • Expenses are average expenses weighted by net generation. • A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of one cent). • Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others."

Table 8.3. Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (With Generation Facilities), 1997 through 2008
(Million Dollars)

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**33,906**	**32,776**	**38,028**	**31,843**	**26,767**	**26,155**	**25,397**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**29,637**	**28,638**	**32,789**	**26,244**	**21,274**	**20,880**	**20,425**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**NA**	**22,642**	**21,731**	**25,922**	**19,575**	**15,386**	**15,120**	**14,917**
Production	NA	NA	NA	NA	NA	17,948	17,176	21,764	15,742	11,923	11,608	11,481
Transmission	NA	NA	NA	NA	NA	872	858	785	781	732	773	725
Distribution	NA	NA	NA	NA	NA	696	680	605	574	516	603	538
Customer Accounts	NA	NA	NA	NA	NA	582	537	600	507	415	390	390
Customer Service	NA	NA	NA	NA	NA	280	315	263	211	160	127	133
Sales	NA	NA	NA	NA	NA	84	74	73	66	49	51	46
Administrative and General	NA	NA	NA	NA	NA	2,180	2,090	1,832	1,695	1,591	1,567	1,602
Maintenance	**NA**	**NA**	**NA**	**NA**	**NA**	**2,086**	**1,926**	**1,904**	**1,815**	**1,686**	**1,631**	**1,609**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**NA**	**3,844**	**3,907**	**4,009**	**3,919**	**3,505**	**3,459**	**3,239**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**NA**	**1,066**	**1,074**	**954**	**936**	**697**	**670**	**660**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**NA**	**4,268**	**4,138**	**5,238**	**5,598**	**5,493**	**5,275**	**4,972**

NA = Not available.
Notes: • In 2004, Form EIA-412 was terminated. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, EIA Form-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.4. Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (Without Generation Facilities), 1997 through 2008
(Million Dollars)

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**12,454**	**11,546**	**10,417**	**9,904**	**9,354**	**8,790**	**8,586**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**11,481**	**10,703**	**9,820**	**9,355**	**8,737**	**8,245**	**8,033**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**NA**	**10,095**	**9,439**	**8,864**	**8,424**	**7,874**	**7,437**	**7,117**
Production	NA	NA	NA	NA	NA	8,865	8,311	7,863	7,486	7,015	6,661	6,240
Transmission	NA	NA	NA	NA	NA	105	93	61	64	48	44	57
Distribution	NA	NA	NA	NA	NA	348	320	311	280	261	230	304
Customer Accounts	NA	NA	NA	NA	NA	172	163	164	155	143	130	139
Customer Service	NA	NA	NA	NA	NA	31	39	26	22	22	21	16
Sales	NA	NA	NA	NA	NA	11	10	15	16	14	9	13
Administrative and General	NA	NA	NA	NA	NA	562	504	423	402	371	342	348
Maintenance	**NA**	**NA**	**NA**	**NA**	**NA**	**418**	**389**	**304**	**286**	**272**	**263**	**338**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**NA**	**711**	**631**	**405**	**394**	**369**	**330**	**354**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**NA**	**257**	**244**	**247**	**251**	**223**	**215**	**225**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**NA**	**974**	**843**	**597**	**549**	**617**	**545**	**552**

NA = Not available.
Notes: • In 2004, Form EIA-412 was terminated. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, EIA Form-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.5. Revenue and Expense Statistics for U.S. Federally Owned Electric Utilities, 1997 through 2008
(Million Dollars)

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**11,798**	**11,470**	**12,458**	**10,685**	**10,186**	**9,780**	**8,833**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**8,763**	**8,665**	**10,013**	**8,139**	**7,775**	**7,099**	**5,999**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**NA**	**6,498**	**6,419**	**7,388**	**5,873**	**5,412**	**5,184**	**4,073**
Production	NA	NA	NA	NA	NA	5,175	5,236	6,247	5,497	4,890	4,735	3,686
Transmission	NA	NA	NA	NA	NA	307	244	354	332	349	323	327
Distribution	NA	NA	NA	NA	NA	1	1	1	2	2	2	1
Customer Accounts	NA	NA	NA	NA	NA	4	10	16	6	1	1	1
Customer Service	NA	NA	NA	NA	NA	63	60	60	48	50	51	42
Sales	NA	NA	NA	NA	NA	20	6	6	10	28	14	13
Administrative and General	NA	NA	NA	NA	NA	927	862	705	467	528	535	444
Maintenance	**NA**	**NA**	**NA**	**NA**	**NA**	**600**	**566**	**521**	**488**	**436**	**476**	**441**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**NA**	**1,335**	**1,351**	**1,790**	**1,471**	**1,623**	**1,175**	**1,214**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**NA**	**329**	**328**	**315**	**308**	**304**	**264**	**272**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**NA**	**3,035**	**2,805**	**2,445**	**2,546**	**2,411**	**2,681**	**2,834**

NA = Not available.
Notes: • In 2004, Form EIA-412 was terminated. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.6. Revenue and Expense Statistics for U.S. Cooperative Borrower Owned Electric Utilities, 1997 through 2008
(Million Dollars)

Description	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Operating Revenue - Electric	**42,076**	**38,208**	**36,723**	**34,088**	**30,650**	**29,228**	**27,458**	**26,458**	**25,629**	**23,824**	**23,988**	**23,321**
Operation and Maintenance Expenses	**38,498**	**34,843**	**33,550**	**31,209**	**27,828**	**26,361**	**24,561**	**23,763**	**22,982**	**21,283**	**21,223**	**20,715**
Operation Including Fuel	**35,770**	**32,229**	**30,920**	**28,723**	**25,420**	**24,076**	**22,383**	**21,703**	**20,942**	**19,336**	**19,280**	**18,405**
Production	30,100	26,929	25,799	23,921	20,752	19,559	18,143	17,714	17,080	15,706	15,683	15,105
Transmission	799	754	748	679	665	637	579	524	525	466	452	339
Distribution	2,325	2,161	2,037	1,895	1,860	1,787	1,681	1,589	1,530	1,451	1,440	1,134
Customer Accounts	890	677	655	612	595	579	545	532	487	455	446	382
Customer Service	176	163	158	147	141	140	136	119	133	132	132	118
Sales	81	78	80	76	80	79	79	88	82	81	77	61
Administrative and General	1,575	1,468	1,444	1,393	1,327	1,295	1,219	1,137	1,104	1,045	1,050	1,266
Depreciation and Amortization	**2,461**	**2,350**	**2,367**	**2,253**	**2,182**	**2,076**	**1,992**	**1,895**	**1,820**	**1,747**	**1,732**	**1,727**
Taxes and Tax Equivalents	**266**	**264**	**262**	**234**	**226**	**209**	**186**	**164**	**220**	**200**	**211**	**583**
Net Electric Operating Income	**3,578**	**3,365**	**3,173**	**2,879**	**2,822**	**2,867**	**2,897**	**2,696**	**2,647**	**2,541**	**2,764**	**2,606**

Note: Totals may not equal sum of components because of independent rounding.
Source: U.S. Department of Agriculture, Rural Utilities Service (prior Rural Electrification Administration), Statistical Report, Rural Electric Borrowers publications, as compiled from RUS Form 7 and RUS Form 12.

Chapter 9. Demand-Side Management

Table 9.1. Demand-Side Management Actual Peak Load Reductions by Program Category, 1997 through 2008
(Megawatts)

Item	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Total Actual Peak Load Reduction	**32,741**	**30,253[R]**	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**
Energy Efficiency	19,650	17,710	15,959	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327
Load Management	13,091	12,543[R]	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958

R = Revised.
Notes: • Data presented are reflective of large utilities. • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.2. Demand-Side Management Program Annual Effects by Program Category, 1997 through 2008

Item	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	Annual Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	19,650	17,710	15,959	15,351	14,272	13,581	13,420	13,027	52,827	49,691	48,775	55,453
Energy Savings (Thousand MWh)	86,001	67,134	62,951	58,891	52,662	48,245	52,285	52,946	12,873	13,452	13,591	13,327
	Annual Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	13,091	12,543[R]	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958
Potential Peak Load Reductions (MW)	26,215	23,087[R]	21,270	21,282	20,998	25,290	26,888	27,730	28,496	30,118	27,840	27,911
Energy Savings (Thousand MWh)	1,824	1,857[R]	865	1,006	2,047	2,020	1,790	990	875	872	392	953

R = Revised.
Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.3. Demand-Side Management Program Incremental Effects by Program Category, 1997 through 2008

Item	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	Incremental Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	5,766	1,649	1,177	1,403	1,521	945	1,054	999	720	695	796	1,065
Energy Savings (Thousand MWh)	10,413	7,426	5,385	5,872	4,522	2,939	3,543	4,402	3,284	3,027	3,324	4,661
Small Utilities												
Actual Peak Load Reduction (MW)	567	349	91	302	204	90	49	20	25	22	12	12
Energy Savings (Thousand MWh)	21	254	9	7	10	8	192	8	8	8	37	10
	Incremental Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	2,980	1,356[R]	1,495	1,009	907	1,084	1,160	1,297	919	1,568	1,821	1,261
Potential Peak Load Reductions (MW)	6,639	3,342[R]	2,544	2,005	2,622	1,981	2,655	2,448	2,439	6,457	2,832	2,475
Energy Savings (Thousand MWh)	166	132[R]	95	133	2	29	65	79	63	67	37	171
Small Utilities												
Actual Peak Load Reduction (MW)	371	1,036	195	153	242	81	54	45	137	54	124	130
Potential Peak Load Reductions (MW)	620	1,423	273	218	422	131	76	177	190	84	160	183
Energy Savings (Thousand MWh)	1	5	4	5	4	4	2	4	9	2	7	19

R = Revised.
Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.4. Demand-Side Management Program Annual Effects by Sector, 1997 through 2008

Item	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	Actual Peak Load Reductions (MW)											
Large Utilities												
Residential	13,592	13,192	10,730	9,432	8,870	9,431	9,137	9,619	9,446	9,976	9,327	10,799
Commercial	11,130	8,054	7,779	7,926	7,194	6,774	6,839	8,210	6,987	7,777	9,482	8,174
Industrial	7,893	8,990[R]	8,692	8,343	7,454	6,594	6,500	6,553	6,141	6,360	7,927	5,812
Transportation	126	17	39	9	14	105	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	460	573	327	2,342	495	498
Total	**32,741**	**30,253[R]**	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**
	Potential Peak Load Reductions (MW)											
Large Utilities												
Residential	16,803	15,263	13,040	12,097	11,967	12,525	12,072	12,274	12,970	12,812	13,022	16,662
Commercial	13,802	10,201	10,006	10,214	9,624	8,943	9,298	10,469	9,114	8,868	12,210	12,896
Industrial	15,091	15,271[R]	14,119	14,260	13,665	17,298	18,321	17,344	18,775	17,237	15,512	11,035
Transportation	169	62	64	62	14	105	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	617	670	510	4,653	686	644
Total	**45,865**	**40,797**	**37,229**	**36,633**	**35,270**	**38,871**	**40,308**	**40,757**	**41,369**	**43,570**	**41,430**	**41,237**
	Energy Savings (Thousand MWh)											
Large Utilities												
Residential	34,188	23,688	21,437	19,255	17,763	13,469	15,438	16,027	16,287	16,263	16,564	17,830
Commercial	38,312	30,725	28,982	28,416	24,624	25,089	24,391	24,217	25,660	23,375	25,125	27,898
Industrial	15,249	14,470[R]	13,348	12,178	12,273	11,156	11,339	10,487	9,160	8,156	3,347	8,684
Transportation	76	109	50	48	51	551	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	2,907	3,206	2,593	2,770	831	1,694
Total	**87,825**	**68,992[R]**	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**

NA = Not available.

R = Revised.

Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.5. Demand-Side Management Program Incremental Effects by Sector, 1997 through 2008

Item	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Actual Peak Load Reductions (MW)												
Large Utilities												
Residential	5,530	1,344	1,012	966	1,361	640	895	790	572	605	599	743
Commercial	2,348	983	759	715	560	528	527	742	515	684	1,176	699
Industrial	866	677[R]	901	731	507	849	680	640	502	929	799	836
Transportation	2	1	0	0	0	12	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	112	124	50	45	43	48
Total	**8,746**	**3,005[R]**	**2,672**	**2,412**	**2,428**	**2,029**	**2,214**	**2,296**	**1,640**	**2,263**	**2,617**	**2,326**
Small Utilities												
Residential	220	871	131	325	280	88	48	32	37	27	35	40
Commercial	287	342	63	71	126	58	41	15	37	22	34	21
Industrial	431	130	92	59	40	25	12	16	62	7	56	61
Transportation	0	42	0	0	0	0	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	0	0	26	19	10	20
Total	**938**	**1,385**	**286**	**455**	**446**	**171**	**101**	**63**	**162**	**76**	**136**	**142**
U.S. Total	**9,684**	**4,390[R]**	**2,958**	**2,867**	**2,874**	**2,200**	**2,317**	**2,361**	**1,802**	**2,339**	**2,753**	**2,468**
Potential Peak Load Reductions (MW)												
Large Utilities												
Residential	7,249	2,374	1,406	1,311	1,680	752	1,311	900	699	753	751	960
Commercial	3,010	1,574	1,114	1,098	894	602	751	1,115	565	718	1,863	853
Industrial	2,144	1,042[R]	1,201	999	1,569	1,551	1,506	1,277	1,815	5,612	1,438	1,669
Transportation	2	1	0	0	0	21	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	141	155	79	68	76	58
Total	**12,405**	**4,991[R]**	**3,721**	**3,408**	**4,143**	**2,926**	**3,709**	**3,447**	**3,159**	**7,151**	**3,628**	**3,540**
Small Utilities												
Residential	315	962	164	367	395	116	64	158	55	41	49	59
Commercial	304	513	95	100	154	73	43	19	51	25	41	35
Industrial	568	243	105	53	77	32	15	18	64	9	70	72
Transportation	0	54	0	0	0	0	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	3	2	44	31	12	30
Total	**1,187**	**1,772**	**364**	**520**	**626**	**221**	**125**	**197**	**215**	**106**	**172**	**196**
U.S. Total	**13,592**	**6,763[R]**	**4,085**	**3,928**	**4,769**	**3,147**	**3,834**	**3,644**	**3,374**	**7,257**	**3,800**	**3,736**
Energy Savings (Thousand MWh)												
Large Utilities												
Residential	4,586	3,515	2,141	2,276	1,842	868	1,203	1,365	856	990	909	1,055
Commercial	4,443	2,831	2,339	2,638	1,815	1,356	1,583	1,867	1,780	1,502	1,703	2,382
Industrial	1,550	1,199[R]	999	1,090	867	732	706	872	547	475	645	1,059
Transportation	1	13	0	*	0	12	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	116	376	164	127	104	336
Total	**10,579**	**7,558[R]**	**5,479**	**6,004**	**4,524**	**2,968**	**3,608**	**4,481**	**3,347**	**3,094**	**3,361**	**4,832**
Small Utilities												
Residential	16	157	9	6	6	7	45	5	9	4	8	10
Commercial	4	98	3	5	7	5	148	3	4	3	6	3
Industrial	2	4	1	*	2	1	2	2	1	1	3	8
Transportation	*	0	0	0	0	0	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	*	3	3	1	1	7
Total	**22**	**259**	**13**	**12**	**14**	**13**	**194**	**13**	**17**	**9**	**18**	**28**
U.S. Total	**10,601**	**7,817[R]**	**5,492**	**6,016**	**4,539**	**2,981**	**3,802**	**4,492**	**3,364**	**3,103**	**3,379**	**4,860**

* = Value is less than half of the smallest unit of measure.

NA = Not available.

R = Revised.

Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.6. Demand-Side Management Program Energy Savings, 1997 through 2008
(Thousand Megawatthours)

Item	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Total Energy Savings	**87,825**	**68,992[R]**	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**
Energy Efficiency	86,001	67,134	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453
Load Management	1,824	1,857[R]	865	1,006	2,047	2,020	1,790	990	875	872	392	953

R = Revised.
Notes: • Data presented are reflective of large utilities. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.7. Demand-Side Management Program Direct and Indirect Costs, 1997 through 2008
(Thousand Dollars)

Item	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Direct Cost[1]	**3,530,470**	**2,364,739[R]**	**1,923,891**	**1,794,809**	**1,425,172**	**1,159,540**	**1,420,937**	**1,455,602**	**1,384,232**	**1,250,689**	**1,233,018**	**1,347,245**
Energy Efficiency	2,344,482	1,664,563	1,258,158	1,169,241	910,115	807,403	1,007,323	1,097,504	938,666	820,108	766,384	892,468
Load Management	1,185,988	700,176[R]	665,733	625,568	515,057	352,137	413,614	358,098	445,566	430,581	466,634	454,777
Indirect Cost[2]	**189,625**	**158,378**	**127,499**	**126,543**	**132,294**	**137,670**	**204,600**	**174,684**	**180,669**	**172,955**	**187,902**	**288,775**
Total DSM Cost[3]	**3,720,095**	**2,523,117[R]**	**2,051,394**	**1,921,352**	**1,557,466**	**1,297,210**	**1,625,537**	**1,630,286**	**1,564,901**	**1,423,644**	**1,420,920**	**1,636,020**

[1] Reflects electric utility costs incurred during the year that are identified with one of the demand-side program categories.
[2] Reflects costs not directly attributable to specific programs.
[3] Reflects the sum of the total incurred direct and indirect cost for the year.
R = Revised.
Notes: • Data presented are reflective of large utilities. • Includes expenditures reported by large electric utilities, only. See the data files for Demand Side Management expenditures of small utilities. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Appendices

Appendix A.
Technical Notes

This appendix describes how the U.S. Energy Information Administration (EIA) collects, estimates, and reports electric power data in the *Electric Power Annual*. Following is a description of the ongoing data quality efforts and sources of data for the *Electric Power Annual*.

Data Quality

The *Electric Power Annual* (EPA) is prepared by the Electric Power Division (EPD), Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), U.S. Energy Information Administration (EIA), U.S. Department of Energy (DOE). EPD performs routine reviews of the data collected and the forms on which they are collected. Additionally, to assure that the data are collected from the complete set of respondents, CNEAF routinely reviews the frames for each data collection.

Unified Data Submission Process

Data are entered directly by respondents into the EPD e-filing system. A small number of hard copy forms are keyed by EPD. All data are subject to review via edits built into the system, additional quality assurance reports, and review by subject matter experts. Questionable data values are verified through contacts with respondents. Also, survey non-respondents are identified and contacted.

Initial edit checks of the data are performed through the system by the respondent. Other program edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, are resolved either by the processing staff or by further information obtained from a telephone call to the respondent company.

Those respondents unable to use the electronic reporting method provide the data in hard copy, typically via fax and e-mail. These data are manually entered into the computerized database and are subjected to the same data edits as those that are electronically submitted. Resolution of questionable data is accomplished via telephone or e-mail contact with the respondents.

Reliability of Data

Annual survey data have nonsampling errors. Non-sampling errors can be attributed to many sources: (1) inability to obtain complete information about all cases (i.e., nonresponse); (2) response errors; (3) definitional difficulties; (4) differences in the interpretation of questions; (5) mistakes in recording or coding the data; and (6) other errors of collection, response, coverage, and estimation for missing data.

Although no direct measurement of the biases due to nonsampling errors can be obtained, precautionary steps were taken in all phases of the frame development and data collection, processing, and tabulation processes, in an effort to minimize their influence.

Imputation. If the reported values appeared to be in error and the data issue could not be resolved with the respondent, or if the facility was a nonrespondent, a regression methodology was used to impute for the facility.[1,2,3,4,5] The regression methodology relies on other data to make estimates for erroneous or missing responses.

The basic technique employed is described in the paper "Model-Based Sampling and Inference[12]," on the EIA website. Additional references can be found on the InterStat website. The basis for the current methodology involves a 'borrowing of strength' technique for small domains.[1,6,7]

Data Revision Procedure

CNEAF has adopted the following procedures with respect to the revision of data disseminated in energy data products:

- Annual survey data are disseminated either as preliminary or final when first appearing in a data product. Data initially released as preliminary will be so noted in the data product. These data are typically released as final by the next dissemination of the same product; however, if final data are available at an earlier interval they may be released in another product.
- After data are disseminated as final, further revisions will be considered if they make a difference of 1 percent or greater at the

[1] Knaub, J.R., Jr. (1999a), "Using Prediction-Oriented Software for Survey Estimation," InterStat, August 1999, http://interstat.statjournals.net/

[2] Knaub, J.R. Jr. (1999b), "Model-Based Sampling, Inference and Imputation," EIA web site: http://www.eia.doe.gov/cneaf/electricity/forms/eiawebme.pdf

[3] Knaub, J.R., Jr. (2005), "Classical Ratio Estimator," InterStat, October 2005, http://interstat.statjournals.net/.

[4] Knaub, J.R., Jr. (2007a), "Cutoff Sampling and Inference," InterStat, April 2007, http://interstat.statjournals.net/.

[5] Knaub, J.R., Jr. (2008), forthcoming. "Cutoff Sampling." Definition in Encyclopedia of Survey Research Methods, Editor: Paul J. Lavrakas, Sage, to appear.

[6] Knaub, J.R., Jr. (2000), "Using Prediction-Oriented Software for Survey Estimation - Part II: Ratios of Totals," InterStat, June 2000, http://interstat.statjournals.net/

[7] Knaub, J.R., Jr. (2001), "Using Prediction-Oriented Software for Survey Estimation - Part III: Full-Scale Study of Variance and Bias," InterStat, June 2001, http://interstat.statjournals.net/

national level. Revisions for differences that do not meet the 1 percent or greater threshold will be determined by the Office Director. In either case, the proposed revision will be subject to the EIA revision policy concerning how it affects other EIA products.

- The magnitudes of changes due to revisions experienced in the past will be included periodically in the data products, so that the reader can assess the accuracy of the data.

The *Electric Power Annual* presents the most current annual data available to the EIA. The statistics may differ from those published previously in EIA publications due to corrections, revisions, or other adjustments to the data subsequent to its original release.

Sensitive Data (Formerly Identified as Data Confidentiality). Most of the data collected on the electric power surveys are not considered business sensitive. However, the data that are classified as sensitive are handled by EPD consistent with EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45 Federal Register 59812 (1980)).

Rounding and Percent Change Calculations

Rounding Rules for Data. To round a number to n digits (decimal places), add one unit to the nth digit if the (n+1) digit is 5 or larger and keep the nth digit unchanged if the (n+1) digit is less than 5. The symbol for a number rounded to zero is (*).

Percent Change. The following formula is used to calculate percent differences.

$$\text{Percent Change} = \left(\frac{x\,(t_2) - x\,(t_1)}{x\,(t_1)} \right) x\,100,$$

where $x\ (t_1)$ and $x\ (t_2)$ denote the quantity at year t_1 and subsequent year t_2.

Data Sources for *Electric Power Annual*

Data published in the *Electric Power Annual* are compiled from forms filed annually or aggregated to an annual basis from monthly forms by electric utilities and electricity generators (see figure on EIA Electric Industry Data Collection on the next page.) The EIA forms used are:

- Form EIA-411, "Coordinated Bulk Power Supply Program Report;"
- Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" [Replaced]
- Form EIA-767, "Steam-Electric Plant Operation and Design Report;" [Replaced]
- Form EIA-860, "Annual Electric Generator Report;" [Modified]
- Form EIA-861, "Annual Electric Power Industry Report;"
- Form EIA-906, "Power Plant Report;" [Replaced] and
- Form EIA-920, "Combined Heat and Power Plant Report." [Replaced]
- Form EIA-923, "Power Plant Operations Report,"

These forms can be found on the EIA Internet website at:
http://www.eia.doe.gov/cneaf/electricity/page/forms.html.
The purpose of each form is summarized below.
Survey data from other Federal sources is also utilized for this publication. They include:

- Department of Energy Form OE-781R, "Annual Report of International Electric Export/Import Data" (Office of Electricity Delivery and Energy Reliability);
- Federal Energy Regulatory Commission Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others;"
- Rural Utility Service Form 7, "Financial and Statistical Report;" and
- Rural Utility Service Form 12, "Operating Report – Financial."

In addition to the above-named forms, the historical data published in the EPA are compiled from the following sources:

- Form EIA-412, "Annual Electric Industry Financial Report,"
- Federal Energy Regulatory Commission Form 423, "Cost and Quality of Fuels for Electric Plants,"
- Form EIA-759, "Monthly Power Plant Report,"
- Form EIA-860A, "Annual Electric Generator Report–Utility,"
- Form EIA-860B, "Annual Electric Generator Report–Nonutility,"
- Form EIA-900, "Monthly Nonutility Power Report,"

Additionally, some data reported in this publication were acquired from the National Energy Board of Canada.

Issues within Non-EIA Historical Data Series: Restructuring of the electric power industry has dramatically increased trade in various locations and altered trends. In California, with the changes initiated to establish electricity markets, the electricity imports and exports data are found on the California's Independent System Operator's web site[8] and are not reported to DOE.

[8] For the reporting year 2001, California - ISO reported electricity purchases from Mexico of 98,645 MWh. They exported 65,475 MWh, thereby having a total net trade of 33,170 MWh of imported electricity in 2001. For the reporting year 2002, California - ISO reported electricity purchases from Mexico of 143,948 MWh. They exported 196,923 MWh, thereby having a total net trade of 52,975 MWh of exported electricity in 2002. In 2003, California - ISO reported electricity purchases of 971,278 MWh and sold 22,510 MWh. For 2004, California - ISO reported electricity purchases of 1,103,928 MWh and sold 48,074 MWh. For 2005, California ISO reported electricity purchases of 1,498,622 MWh and sales of 103,051 MWh. For

Meanings of Symbols Appearing in Tables

Some symbols appearing in the data tables have further standardized to describe all data collected by the Electric Power Division of EIA. The meanings are indicated in footnotes on the applicable tables and include the following:

*	The value reported is less than half of the smallest unit of measure, but is greater than zero.
P	Usage of this symbol indicates a preliminary value. The P is defined in endnotes as "P=Preliminary data."
NM	Data value is not meaningful when compared to the same value for the previous month or the previous year. This symbol is also used to indicate a data value is not meaningful due to having a high Relative Standard Error (RSE).

Form EIA-411

The Form EIA-411 is filed as a mandatory report except for Schedule 7 (Transmission Outages) that is still voluntary reported. The information reported includes: (1) actual energy and peak demand for the preceding year and five additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; and (5) bulk power system maps. The report presents various North American Electric Reliability Corporation (NERC) regional council aggregate totals for their member electric utilities, with some nonmember information included. The eight NERC councils submit data for the Form EIA-411 to NERC. A joint response, through the NERC Headquarters, is filed annually on July 15. The forms are compiled from data furnished by electricity generators and electric utilities (members, associates, and nonmembers) within the council areas.

Instrument and Design History. The Form EIA-411 program was initiated under the Federal Power Commission Docket R-362, Reliability and Adequacy of Electric Service, and Orders 383-2, 383-3, and 383-4. The Department of Energy, established in October 1977, assumed the responsibility for this activity. Until 2008, this form was considered voluntary under the authority of the Federal Power Act (Public Law 88-280), The Federal Energy Administration Act of 1974 (Public Law 93-275), and the Department of Energy Organization Act (Public Law 95-91). The responsibility for collecting these data had been delegated to the Office of Emergency Planning and Operations within the Department of Energy and was transferred to EIA for the reporting year 1996.

Issues within Historical Data Series

The Florida Reliability Coordinating Council (FRCC) separated itself from the Southeastern Electric Reliability Council (SERC) in the mid-1990s and all time series data have been adjusted. In 1998, several utilities realigned from Southwest Power Pool (SPP) to SERC. Adjustments were made to the information to account for the separation and to address the tracking of shared reserve capacity that was under long-term contracts with multiple members. Name changes altered both the Mid-Continent Area Power Pool (MAPP) to the Midwest Reliability Organization (MRO) and the Western Systems Coordinating Council (WSCC) to the Western Electricity Coordinating Council (WECC). The MRO membership boundaries have altered over time, but WECC membership boundaries have not. The utilities in the associated regional entity identified as the Alaska System Coordination Council (ASCC) dropped their formal participation in NERC. Both the States of Alaska and Hawaii are not contiguous with the other continental States and have no electrical interconnections. At the close of calendar year 2005, the following reliability regional councils were dissolved: East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Mid-America Interconnected Network (MAIN).

On January 1, 2006, the Reliability*First* Corporation (RFC) came into existence as a new regional reliability council. Individual utility membership in the former ECAR, MAAC, and MAIN councils mostly shifted to RFC. However, adjustments in membership as utilities joined or left various reliability councils impacted MRO, SERC, and SPP. The Texas Regional Entity (TRE) was formed from a delegation of authority from NERC to handle the regional responsibilities of the Electric Reliability Council of Texas (ERCOT). The revised delegation agreements covering all the regions were approved by the Federal Energy Regulatory Commission on March 21, 2008. Reliability Councils that are unchanged include: Florida Reliability Coordinating Council (FRCC), Northeast Power Coordinating Council (NPCC), and the Western Electricity Coordinating Council (WECC). The historical time series have not been adjusted to account for individual membership shifts.

The new NERC Regional Entity names are as follows:

- Florida Reliability Coordinating Council (FRCC),
- Midwest Reliability Organization (MRO),
- Northeast Power Coordinating Council (NPCC),
- Reliability*First* Corporation (RFC),

2006, California - ISO reported electric purchases of 1,048,610 MWh and sales of 498, 268 MWh. In 2007, the California – ISO reported electric purchases on 1,178,996 MWh and 216,496 MWh sales with Mexico. In 2008, the California - ISO reported electriciy purchases on 1,189,504 MWh and 216,321 MWh sales with Mexico.

- Southeastern Electric Reliability Council (SERC),
- Southwest Power Pool (SPP),
- Texas Regional Entity (TRE), and
- Western Electricity Coordinating Council (WECC).

Concept of Demand within the EIA-411: Historically, the Form EIA-411 has used the electric power industry's methodology for examining aggregated supply and demand. To get to the megawatts of power that are determined to be available for planning purposes each year, different categories are subtracted from the theoretical true totals. The definitions for demand are as follows:

- **Net Internal Demand**: Internal Demand less Direct Control Load Management and Interruptible Demand.
- **Internal Demand**: To collect these data, NERC develops a Total Internal Demand that is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) is not included nor are any requirement customer (utility) load or capacity found behind the line meters on the system.
- **Direct Control Load Management**: Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises; it does not included Interruptible Demand.
- **Interruptible Demand**: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted as the time of the NERC Council or Reporting party seasonal peak by direct control of the system operator. In some instances, the demand reduction may be effected by direct action of the system operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Sensitive Data (Formerly Identified as Data Confidentiality). Power flow cases and maps are considered business sensitive.

Form EIA-412 [Terminated]

The Form EIA-412 was used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Those publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had 150,000 megawatthours of sales to ultimate consumers and/or 150,000 megawatthours of sales for resale for the two previous years, as reported on the Form EIA-861, "Annual Electric Utility Report," were required to submit the Form EIA-412. The Form EIA-412 was made available in January to collect data as of the end of the preceding calendar year. The completed surveys were due to EIA on or before April 30.

Instrument and Design History. The Federal Power Commission (FPC) created the FPC Form 1M in 1961 as a mandatory survey. It became the responsibility of the EIA in October 1977 when the FPC was merged with DOE. In 1979, the FPC Form 1M was superseded by the Economic Regulatory Administration (ERA) Form ERA-412, and in January 1980 by the Form EIA-412.

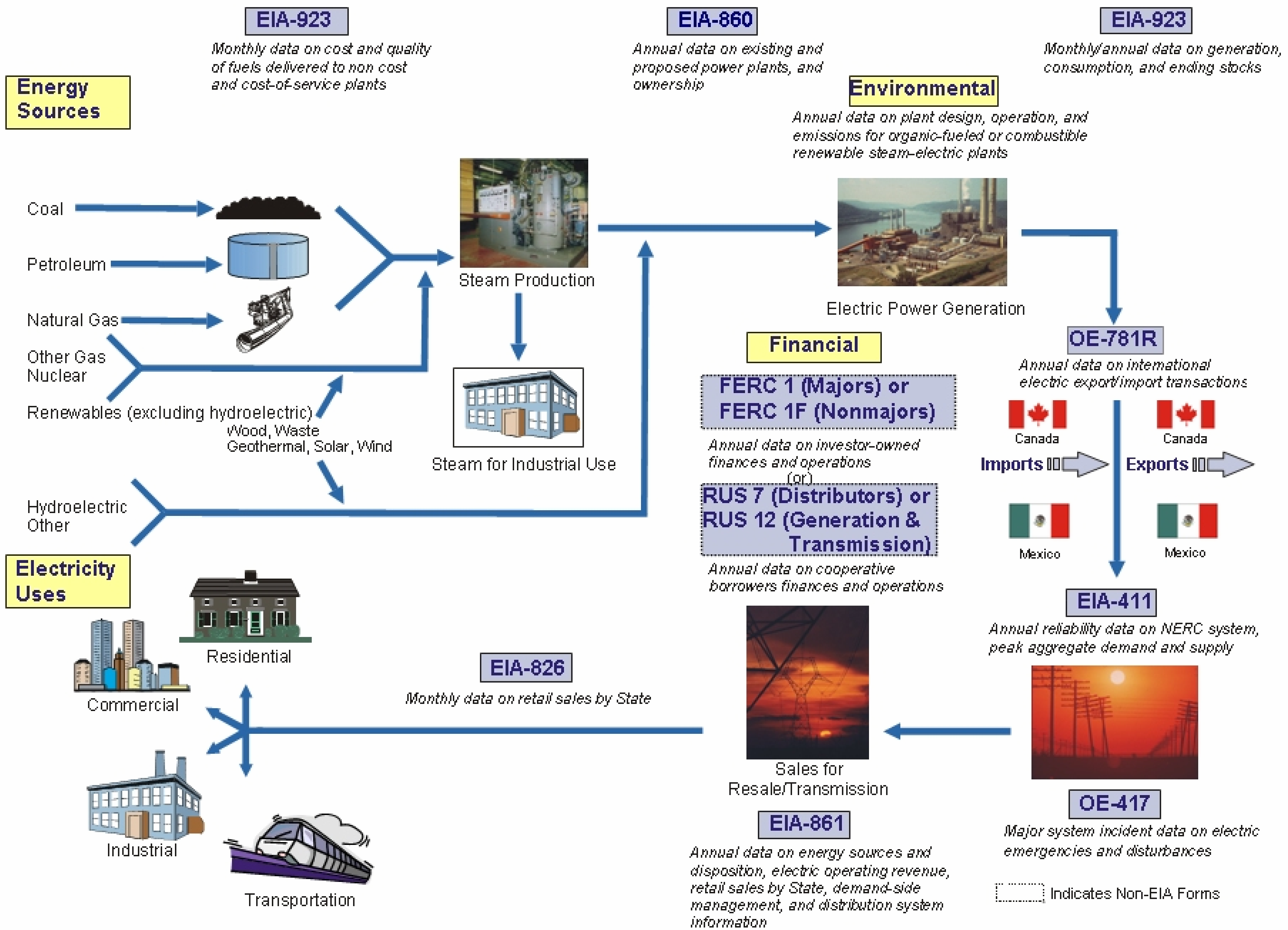
The 1996-1997 data represent those electric utilities meeting a threshold of 120,000 megawatthours for ultimate consumers' sales and/or resales. The criteria used to select the respondents for this survey fit approximately 500 publicly owned electric utilities. Federal electric utilities are required to file the Form EIA-412. The financial data for the U.S. Army Corps of Engineers (except for Saint Mary's Falls at Sault Ste. Marie, Michigan); the U.S. Department of Interior, Bureau of Reclamation; and the U.S. International Boundary and Water Commission were collected on the Form EIA-412 from the Federal power marketing administrations. The form was terminated after the 2003 data year.

Issues within Historical Data Series

Beginning with the 2001 data collection, the plant statistics reported on Schedule 9 were also collected from unregulated entities that own plants with a nameplate capacity of 10 megawatts or greater. Also beginning with the 2003 collection, the transmission data reported in Schedules 10 and 11 were collected from each generation and transmission cooperative owning transmission lines having a nominal voltage of 132 kilovolts or greater.

For 2001 - 2003, California Department of Water Resources - Electric Energy Fund data were included in the EIA-412 data tables. In response to the energy shortfall in California, in 2001 the California State legislature authorized the California Department of Water Resources, using its undamaged borrowing capability, to enter the wholesale markets on behalf of the California retail customers effective on January 17, 2001 and for the period ending December 31, 2002. Their 2001 revenue collected was $5,501,000,000 with purchased power costs of $12,055,000,000. Their 2002 revenue collected was $4,210,000,000 with purchased power costs of $3,827,749,811. Their 2003 revenue collected was $4,627,000,000 with purchased power costs of $4,732,000,000. The California Public Utility Commission was required by statute to establish the procedures for retail revenue recovery mechanisms for their purchase power costs in the future.

EIA Electric Industry Data Collection



Sensitive Data (Formerly Identified as Data Confidentiality). The nonutility data collected on Schedule 9 “Electric Generating Plant Statistics” for “Cost of Plant” and “Production Expenses,” are considered business sensitive.

Form EIA-423 [Replaced in 2008 by the Form EIA-923]

The Form EIA-423, “Monthly Cost and Quality of Fuels for Electric Plants Report,” collected information from selected electric generating plants in the United States. The data collected on this survey included the cost and quality of fossil fuels delivered to nonutility plants to produce electricity. These plants included independent power producers (including those facilities that formerly reported on the FERC Form 423) and commercial and industrial combined heat and power producers whose total fossil-fueled nameplate generating capacity is 50 or more megawatts.

Instrument and Design History. The Form EIA-423[1] was originally implemented in January 2002 to collect monthly cost and quality data for fossil fuel receipts from owners or operators of nonutility electricity generating plants. It was terminated on January 1, 2008, and replaced by the Form EIA-923, "Power Plant Operations Report."

Issues within Historical Data Series

Natural gas values for 2001 forward do not include blast furnace gas or other gas.

Sensitive Data (Formerly Identified as Data Confidentiality). Plant fuel cost data collected on the survey are considered business sensitive. State and national level aggregations will be published in this report if sufficient data are available to avoid disclosure of individual company and plant level costs.

FERC Form 423 [Replaced in 2008 by Form EIA-923]

The Federal Energy Regulatory Commission (FERC) Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants,” was administered by FERC. The data were downloaded from the Commission’s website into an EIA database. The Form was filed by approximately 600 regulated plants. To meet the old criteria for filing, a plant must have had a total steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity of 50 or more megawatts. Only fuel delivered for use in steam-turbine and combined-cycle units was reported. Fuel received for use in gas-turbine or internal-combustion units that was not associated with a combined-cycle operation is not reported. The 2007 data collection represents the last year where the information came from the FERC Form 423.

Instrument and Design History. On July 7, 1972, the Federal Power Commission (FPC) issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, legally creating the FPC Form 423. Originally, the form was used to collect data only on fossil-steam plants, but was amended in 1974 to include data on internal-combustion and combustion-turbine units. The FERC Form 423 replaced the FPC Form 423 in January 1983. The FERC Form 423 eliminated peaking units, for which data were previously collected on the FPC Form 423. In addition, the generator nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All historical FPC Form 423 data in this publication were revised to reflect the new generator-nameplate-capacity threshold of 50 or more megawatts reported on the FERC Form 423. In January 1991, the collection of data on the FERC Form 423 was extended to include combined-cycle units. Historical data have not been revised to include these units. Starting with the January 1993 data, the FERC began to collect the data directly from the respondents. On January 1, 2008, EIA assumed took responsibility for collection and the information is now under the Form EIA-923, "Power Plant Operations Report."

Formulas and Methodologies. Data for the FERC Form 423 were collected at the plant level. These data were then used in the same formulas used by the Form EIA-423 to produce aggregates and averages for each fuel type at the State, Census division, and U.S. levels.

Issues within Historical Data Series. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time.

Receipts data for regulated utilities were compiled by EIA from data collected by the Federal Energy Regulatory Commission (FERC) on the FERC Form 423. These data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late filing issues in the FERC Form 423 data. Due to the estimation procedure discussed previously, 2003 and later data cannot be directly compared to previous years’ data.

Sensitive Data (Formerly Identified as Data Confidentiality). Data collected on FERC Form 423 are not considered to be business sensitive.

[1] Due to the restructuring of the electric power industry, many plants which had historically submitted this information for utility plants on the FERC Form 423 (see subsequent section) were being transferred to the nonutility sector. As a result, a large percentage of fossil fuel receipts were no longer being reported. The Form EIA-423 was implemented to fill this void and to capture the data associated with existing nonregulated power producers. Its design closely follows that of the FERC Form 423.

Form EIA-767 [Replaced by Forms EIA-860 and EIA-923]

The Form EIA-767 was used to collect data annually on plant operations and equipment design, including boiler, generator, cooling system, air pollution control equipment, and stack characteristics. Data were collected from a mandatory restricted-universe census of all electric power plants with a total existing or planned organic-fueled or combustible renewable steam-electric generator nameplate rating of 10 or more megawatts. The entire form was filed by approximately 800 power plants with a nameplate capacity of 100 or more megawatts. An additional 600 power plants with a nameplate capacity under 100 megawatts submitted information only on fuel consumption and quality, boiler and generator configuration, and nitrogen oxides, mercury, particulate matter, and sulfur dioxide controls.

Instrument and Design History. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, "Steam-Electric Plant Air and Water Quality Control Data," was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and retitled Form EIA-767, "Steam-Electric Plant Operation and Design Report." In 1986, the respondent universe of 700 was increased to 900 to include plants with nameplate capacity from 10 megawatts to 100 megawatts. In 2002, the respondent universe was increased by almost 1,370 plants with the addition of non-utility plants. <u>Collection of data via the form was suspended for the 2006 data year</u>. Starting for the collection of 2007 calendar year data, most of the Form EIA-767 information is now collected on either the revised Form EIA-860, "Annual Electric Generator Report" or the new Form EIA-923, "Power Plant Operations Report."

Estimation of EIA-767 Data. No estimation of Form EIA-767 data was performed, as 100 percent of the forms were collected.

Issues within Historical Data Series

None.

Sensitive Data (Formerly Identified as Data Confidentiality). Historical latitude and longitude data collected on the Form EIA-767 are considered business sensitive.

Form EIA-860

The Form EIA-860 is a mandatory census of all existing and planned electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The survey is used to collect data on existing power plants and 5-year plans for constructing new plants, generating unit additions, modifications, and retirements in existing plants. Data on the survey are collected at the individual generator level. Certain power plant environmental related data are now collected at the boiler level. These data include environmental equipment design parameters and boiler air emission standards and boiler emission controls. The Form EIA-860 is made available in January to collect data for the previous year and is due to EIA by February 15 of each year.

Instrument and Design History. The Form EIA-860 was originally implemented in January 1985 to collect plant data on electric utilities as of year-end 1984. In January 1999, the Form EIA-860 was renamed the Form EIA-860A and was implemented to collect data as of January 1, 1999.

In 1989, the Form EIA-867, "Annual Nonutility Power Producer Report," was initiated to collect plant data on unregulated entities with a total generator nameplate capacity of 5 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. In 1998, the Form EIA-867, was renamed Form EIA-860B, "Annual Electric Generator Report – Nonutility." The Form EIA-860B was a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts.

Beginning with data collected for the year 2001, the infrastructure data collected on the Form EIA-860A and the Form EIA-860B were combined into the new Form EIA-860 and the monthly and annual versions of the Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Starting with the 2007 data,, design parameters data formerly collected on Form EIA-767 are collected on Form EIA-860. These include design parameters associated with certain steam-electric plants' boilers, cooling systems, flue gas particulate collectors, flue gas desulfurization units and stacks and flues.

Estimation of EIA-860 Data. Of the 17,658 existing generators in the 2008 Form EIA-860 frame, imputation was performed on 2 generators. These 2 generators account for less than 0.01 percent of the existing capacity. Imputation was performed at the respondent-plant-generator levels, using the 2007 data for the respondent.

Issues within Historical Data Series

Categorization of Capacity by Business Sector: There is a small number of electric utility combined heat and power plants, as well as a small number of industrial and commercial generating facilities that are not combined heat and power. For the purposes of this report the data for these plants is included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and "Combined Heat and Power, Commercial."

Some capacity in 2001 through 2004 is classified based on the operating company's classification as an electric utility or an independent power producer. Starting in the *Electric Power Annual 2006*, capacity by producer type was determined at the generating plant level for 2005 and 2006, based on whether the plant is an electric utility plant or an electric nonutility plant. Therefore, the revised capacity by producer type for 2005 is comparable to the capacity for 2006 and later years, by producer type. The previously published 2005 capacity by producer type was determined based on the operating company's classification of electric utility or electric nonutility.

Planned Capacity: Delays and cancellations may have occurred subsequent to respondent data reporting as of December 31 of the data year.

Capacity by Energy Source: Prior to the *Electric Power Annual* 2005, the capacity for generators for which natural gas or petroleum was the most predominant energy source was presented in the categories "petroleum only," "natural gas only" and "dual-fired." The "dual-fired" category, which was EIA's effort to infer which generators could fuel-switch between natural gas and fuel oil, included only the capacity of generators for which the most predominant energy source and second most predominant energy source were reported as natural gas or petroleum. Beginning with the *Electric Power Annual* 2005 capacity is assigned to energy source based solely on the most predominant (primary) energy source reported for a generator. The "dual-fired" category was eliminated. Separately, summaries of capacity associated with generators with fuel-switching capability are presented for 2005 and later years.. These summaries are based on data collected from new questions added to the Form EIA-860 survey that directly address the ability of generators to switch fuels and co-fire fuels.

In the *Electric Power Annual 2005*, certain petroleum-fired capacity was misclassified as natural gas-fired capacity for 1995 – 2003. This has been corrected in the *Electric Power Annual 2006*. Corrections were noted as revised data.

Sensitive Data (Formerly Identified as Data Confidentiality). The tested heat rate data collected on the Form EIA-860 are considered business sensitive.

Form EIA-861

The Form EIA-861 is a mandatory census of electric power industry participants in the United States. The survey is used to collect information on power production and sales data from approximately 3,300 respondents. About 3,200 are electric utilities, and the remainder is nontraditional entities such as energy service providers, or the unregulated subsidiaries of electric utilities and power marketers. The data collected are used to maintain and update the EPD electric power industry participant frame database. The Form EIA-861 is made available in January of each year to collect data as of the end of the preceding calendar year and is due by April 30.

Transportation Sector. Prior to 2003, sales of electric power to the Transportation sector of the U. S. economy were included in the Other sector, along with sales to customers for public buildings, traffic signals, public street lighting, and sales to irrigation consumers. Beginning with the 2003 collection cycle, sales to the Transportation sector are collected separately. Sales to public-sector customers for public buildings, traffic signals and street lighting, previously reported in the Other sector, were reclassified as Commercial sector sales. Sales to irrigation customers, where separately identified, were reclassified to the Industrial sector.

On the Form EIA-861, the Transportation sector is defined as electrified rail, primarily urban transit, light rail, automated guideway, and other rail systems whose primary propulsive energy source is electricity. Electricity sales to transportation sector consumers whose primary propulsive energy source is not electricity (i.e., gasoline, diesel fuel, etc.) are not included.

Benchmark statistics were reviewed from outside surveys, most notably the U.S. Department of Transportation, Federal Transit Administration's National Transportation Database, a source previously used by EIA to estimate electricity transportation consumption. The U.S. Department of Transportation (DOT) survey indicated the State and city locations of expected respondents. The EIA-861 survey methodology assumed that sales, revenue, and customer counts associated with these mass transit systems would be provided by the incumbent utilities in these areas, relying on information drawn routinely from rate schedules and classifications designed to serve the sector separately and distinctly. In 2007, 72 respondents reported transportation data in 28 States.

Imputation. The *Electric Power Annual* (EPA) reports total retail sales volumes (megawatthours) and customer counts in States with deregulated markets as the sum of bundled sales reported by full-service providers and delivery reported by transmission and distribution utilities. EPD has concluded that the retail sales data reported by delivery utilities are more reliable than data reported by power marketers and Energy Service Providers (ESPs).

The reporting methodology change uses sales volumes and customer counts reported by distribution utilities, and add only an incremental revenue value, representing revenue associated with missing sales assumed to be attributable to the ESPs that were under-represented in the survey frame. In some cases, adjustments are also made to retail sales, revenue, and customer counts associated with underreporting of delivery volumes by one or more of the distribution utilities. In those cases, EIA assumes that total load served by those utilities is accurate, and that any underreporting of delivery volumes resulted from misclassifying actual delivery volumes as bundled sales. Therefore, in those instances EIA adjusted upwards the delivery volumes, revenues, and customer counts and made a corresponding equivalent offset (reduction) to the bundled sales by State and end-use sector.

Data for 2007 reflect imputed retail sales data to account for non-respondents on Form EIA-861. The imputation methodology used is the same as that used in preparing the *Electric Power Monthly* (whose retail sales data are drawn from Form EIA-826). Form EIA-826 is a monthly stratified sample of approximately 454 investor-owned and public utilities, as well as a census of energy service providers and power marketers. If an EIA-861 respondent did not file an annual form for 2007, their data were assumed to be the amount imputed during the year using the EIA-826 sample form collection and imputation process.

Instrument and Design History. The Form EIA-861 was implemented in January 1985 for collection of data as of year-end 1984. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Reconciliation. The EPA reports total retail sales volumes (megawatthours) and customer counts in States with deregulated markets as the sum of bundled sales reported by full-service providers and delivery reported by transmission and distribution utilities. EPD has concluded that the retail sales data reported by delivery utilities are more reliable than data reported by power marketers and ESPs.

Average Retail Price of Electricity. This represents the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector. State-level weighted average prices per unit of sales are calculated as the ratio of revenue to sales.

The electric revenue used to calculate the average retail price of electricity is the operating revenue reported by the electric power industry participant. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric power industry participant operating revenues also include ratepayer reimbursements for State and Federal income taxes and taxes other than income taxes paid by the utility.

The average retail price of electricity reported in this publication by sector represents a weighted average of consumer revenue and sales within sectors and across sectors for all consumers, and does not reflect the per kWh rate charged by the electric power industry participant to the individual consumers. Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric power industry participant for providing electrical service.

Issues within Historical Data Series

Beginning in 2003 the Other sector has been eliminated. Data previously assigned to the Other sector have been reclassified as follows: lighting for public buildings, streets, and highways, interdepartmental sales, and other sales to public authorities are now included in the Commercial sector; agricultural and irrigation sales where separately identified are now included in the Industrial sector; and a new sector, Transportation, includes electrified rail and various urban transit systems (such as automated guideway, trolley, and cable) where the principal propulsive energy source is electricity. Comparisons of data across years should include consideration of these reclassification changes.

Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. Also, the number of ultimate customers is an average of the number of customers at the close of each month.

Demand-Side Management: The following definitions are supplied to assist in interpreting Tables 9.1 through 9.5. Utility costs reflect the total cash expenditures for the year, in nominal dollars, that flow out to support demand-side management (DSM) programs.

- **Actual Peak Load Reduction.** The actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Load Reduction). Actual peak load reduction is reported by large utilities only.
- **Energy Savings.** The change in aggregate electricity use (measured in megawatthours) for consumers that participate in a utility DSM program. These savings represent changes at the consumer's meter (i.e., exclude transmission and distribution effects) and reflect only activities that are undertaken specifically in response to utility-administered programs, including those activities implemented by third parties under contract to the utility.
- **Large Utilities.** Those electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2008 and, for years prior, the threshold was set at 120 million kilowatthours.
- **Potential Peak Load Reductions.** The potential peak load reduction as a result of load management, and also the actual peak load reduction achieved by energy efficiency programs.

Wholesale Trade: Alaska and Hawaii are not included.

Sensitive Data (Formerly Identified as Data Confidentiality). Data collected on the Form EIA-861 are not considered to be business sensitive.

Form EIA-906 [Replaced in 2007 by Form EIA-923]

The Form EIA-906 was used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content, from electric utilities and nonutilities. Data were collected monthly from a model-based sample of approximately 1,700 utility and nonutility electric power plants. The form was also used to collect these statistics from another 2,667 plants (i.e., all other generators 1 MW or greater) on an annual basis. The 2007 data collection represents the last year where the information came from the Form EIA-906. Starting with the collection of 2008 calendar year data, the Form EIA-906 information is now collected on a replacement form (the Form EIA-923). The monthly data for Form EIA-906 is now being collected on the replacement form starting in January of 2008.

Instrument and Design History. The Bureau of Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry prior to 1936. After 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the Form FPC-4. The Federal Power Act, Section 311 and 312, and FPC Order 141 defined the legislative authority to collect power production data. The Form EIA-759 replaced the Form FPC-4 in January 1982. In 1996, the Form EIA-900 was initiated to collect sales for resale data from unregulated entities. In 1998, the form was modified to collect sales for resale, gross generation, and sales to end user data. In 1999, the form was modified to collect net generation, consumption, and ending stock data. In 2000, the form was modified to include useful thermal output data.

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. In January 2008, the Form EIA-923 superseded this form.

Issues within Historical Data Series

There were a small number of electric commercial and industrial- only plants that are included in the combined heat and power category. For the purposes of this report the data for these plants were included, respectively, in the following categories: “Electricity Generators, Electric Utilities,” “Combined Heat and Power, Industrial,” and “Combined Heat and Power, Commercial.” No information on the production of Useful Thermal Output (UTO) or fuel consumption for

UTO was collected or estimated for the electric utility combined heat and power plants.

Sensitive Data (Formerly Identified as Data Confidentiality). The only business sensitive data element collected on the Form EIA-906 is fuel stocks at the end of the reporting period.

Form EIA-920 [Replaced in 2007 by Form EIA-923]

The Form EIA-920, "Combined Heat and Power Plant Report" was used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content of combined heat and power (CHP) plants. Data were collected monthly from a sample of plants. The form was also used to collect the statistics from combined heat and power plants on an annual basis.

Instrument and Design History. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. Starting with the collection of 2007 calendar year data, the Form EIA-920 information is now collected on a replacement form (the Form EIA-923). The monthly data for Form EIA-920 began collection on the replacement form in January of 2008. (For further information on predecessor forms, see the discussion of the EIA-906 survey, above.) The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Issues within Historical Data Series

There are a small number of electric commercial and industrial only plants that are included in the combined heat and power category. For the purposes of this report the data for these plants are included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and "Combined Heat and Power, Commercial." No information on the production of UTO or fuel consumption for UTO was collected or estimated for the electric utility combined heat and power plants.

Sensitive Data (Formerly Identified as Data Confidentiality). The only business sensitive data element collected on the Form EIA-920 were fuel stocks at the end of the reporting period.

Form EIA-923

Form EIA-923, "Power Plant Operations Report," is used to collect information on receipts and cost of fossil fuels, fuel stocks, generation, consumption of fuel for generation, and environmental data (e.g., emission controls and cooling systems). Data are collected from a monthly sample of approximately 1,600 plants, which includes a census of nuclear and pumped storage hydroelectric plants. The plants in the monthly sample report their receipts, cost and stocks of fossil fuels, electric power generation, and the total consumption of fuels for both electric power generation and, if a combined heat and power plant, useful thermal output. At the end of the year, the monthly respondents report their annual source and disposition of electric power (nonutilities only), and if applicable, the environmental data on the Form EIA-923 Supplemental Form (Schedules 6, 7, and 8A to 8F). Approximately 3,300 plants, representing all generators not included in the monthly sample and with a nameplate capacity of 1 MW or more, report data on the entire form (Schedules 1 to 8F, as applicable) annually. In addition to electric power generating plants, respondents include fuel storage terminals without generating capacity that receives shipments of fossil fuels for eventual use in electric power generation. The monthly data are due by the last day of the month following the reporting period.

Receipts of fossil fuels, fuel cost and quality information, and fuel stocks at the end of the reporting period are all reported at the plant level. Fuel receipts and costs are collected from plants with a nameplate capacity of 50 MW or more and burn fossil fuels. Plants that burn organic fuels and have a steam turbine capacity of at least 10 megawatts report consumption at the boiler level and generation at the generator level for each month, regardless of whether the plant reports in the monthly sample or reports once a year (annually). For all other plants, consumption is reported at the prime-mover level. For these plants, generation is reported either at the prime-mover level or, for noncombustible sources (e.g., wind, nuclear), at the prime-move and energy source level (including generating unit for nuclear only). The source and disposition of electricity is reported annually for nonutilities at the plant level, as is revenue from sales for resale. Additional operational data, including environmental data, are collected annually from facilities that have a steam turbine capacity of at least 10 megawatts.

Instrument and Design History:

Receipts and Cost and Quality of Fossil Fuels

On July 7, 1972, the Federal Power Commission (FPC) issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, legally creating the FPC Form 423. Originally, the form was used to collect data only on fossil-steam plants, but was amended in 1974 to include data on internal-combustion and combustion-turbine units. The FERC Form 423 replaced the FPC Form 423 in January 1983. The FERC Form 423 eliminated peaking units, for which data were previously collected on the FPC Form 423. In addition, the generator nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All historical FPC Form 423 data in this publication were revised to reflect the new generator-nameplate-capacity threshold of 50 or more megawatts reported on the FERC Form 423. In January 1991, the collection of data on the FERC Form 423 was extended to include combined-cycle units. Historical data have not been revised to include these units. Starting with the January 1993 data, the FERC began to collect the data directly from the respondents.

The Form EIA-423 was originally implemented in January 2002 to collect monthly cost and quality data for fossil fuel receipts from owners or operators of nonutility electricity generating plants. Due to the restructuring of the electric power industry, many plants which had historically submitted this information for utility plants on the FERC Form 423 (see above) were being transferred to the nonutility sector. As a result, a large percentage of fossil fuel receipts were no longer being reported. The Form EIA-423 was implemented to fill this void and to capture the data associated with existing non-regulated power producers. Its design closely followed that of the FERC Form 423.

Both the Form EIA-423 and FERC-423 were superseded by Form EIA-923 (Schedule 2) in January of 2008. The EIA-923 maintains the same 50 megawatt threshold for these data. However, not all data are collected monthly on the new form. Beginning with 2008 data, a sample of the respondents will report monthly, with the remainder reporting annually (monthly values will be imputed via regression). For 2007, Schedule 2 annual data will not be collected or imputed. Most of the plants required to report on Schedule 2 already submitted their 2007 receipts data on a monthly basis.

Generation and Consumption

The Bureau of Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry prior to 1936. After 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the Form FPC-4. The Federal Power Act, Section 311 and 312, and FPC Order 141 defined the legislative authority to collect power production data. The Form EIA-759 replaced the Form FPC-4 in January 1982.

In 1996, the Form EIA-900 was initiated to collect sales for resale data from unregulated entities[10]. In 1998, the form was modified to collect sales for resale, gross generation, and sales to end user data. In 1999, the form was modified to collect net generation, consumption, and ending stock data[11]. In 2000, the form was modified to include useful thermal output data.

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Forms EIA-906 and EIA-920 were superseded by survey form EIA-923 beginning in January 2008 with the collection of annual 2007 data and monthly 2008 data.

Steam Electric Plant Operational Data

The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, “Steam-Electric Plant Air and Water Quality Control Data,” was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and retitled Form EIA-767, “Steam-Electric Plant Operation and Design Report.” In 1986, the respondent universe of 700 was increased to 900 to include plants with nameplate capacity from 10 megawatts to 100 megawatts. In 2002, the respondent universe increased to above 1,370 plants plus the addition of non-utility plants. Collection of data via the Form EIA-767 was suspended for the 2006 data year, but was resumed on the Form EIA-923 for data year 2007. For respondents selected to be in the monthly sample for Form EIA-906 or EIA-920 in 2007, and were thus were not annual filers for Form EIA-923, this data was collected for 2007 via a one-time supplemental filing in 2008.

Data Processing and Data System Editing. Respondents are encouraged to enter data directly into a computerized database via the e-filing system. A variety of automated quality control mechanisms are run during this process, such as range checks and comparisons with historical data. These edit checks were performed as the data were provided, and many problems that are encountered are resolved during the reporting process. Those plants that are unable to use the electronic reporting medium provide the data in hard copy, typically via fax. These data were manually entered into the computerized database. The data were subjected to the same edits as those that were electronically submitted.

If the reported data appeared to be in error and the data issue could not be resolved by follow up contact with the respondent, or if a facility was a nonrespondent, a regression methodology was used to impute for the facility.

Imputation. For data collected monthly, regression prediction, or imputation, is done for all missing data including non-sampled units and any nonrespondents. For data collected annually, imputation is done for nonrespondents.

For gross generation and total fuel consumption, multiple regression is used for imputation. For gross generation, the regressors are prior year average generation for the same fuel, prior year average generation from other fuels, and nameplate capacity. Regressors for total fuel consumption are prior year average fuel consumption from the same fuel, prior year average consumption from other fuels, and nameplate capacity. For stocks, a linear combination of the prior month's ending stocks value and the current month's consumption and receipts values is used.

Only approximately 0.02% of the national total gross generation for 2007 reported here is imputed, although this will vary by State and energy source.

Net generation, where not reported, is estimated by using a fixed ratio to gross generation by prime-mover type.

Receipts of Fossil Fuels. Note that for 2007, this data was collected on Form EIA-423 and FERC Form 423.

Receipts data, including cost and quality of fuels, are collected at the plant level from selected electric generating plants and fossil-fuel storage terminals in the United States. These plants include independent power producers, electric utilities, and commercial and industrial combined heat and power producers whose total fossil-fueled nameplate capacity is 50 megawatts or more (excluding storage terminals, which do not produce electricity). The data on cost and quality of fuel shipments are then used in the following formulas to produce aggregates and averages for each fuel type at the State, Census division, and U.S. levels. For these formulas, receipts and average heat content are at the plant level. For each geographic region, the summation sign, $\sum$, represents the sum of all facilities in that geographic region.

For coal, units for receipts are in tons and units for average heat contents (A) are in million Btu per ton.

For petroleum, units for receipts are in barrels and units for average heat contents (A) are in million Btu per barrel.

For gas, units for receipts are in thousand cubic feet (Mcf) and units for average heat contents (A) are in million Btu per thousand cubic foot.

For each of the above fossil fuels:

$$\text{Total Btu} = \sum_i (R_i \ x \ A_i),$$

where i denotes a facility; R_i = receipts for facility i; A_i = average heat content for receipts at facility i;

$$\text{Weighted Average Btu} = \frac{\sum_i (R_i \ x \ A_i)}{\sum_i R_i},$$

where i denotes a facility; R_i = receipts for facility i; and, A_i = average heat content for receipts at facility i.

The weighted average cost in cents per million Btu is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{\sum_i (R_i \ x \ A_i \ x \ C_i)}{\sum_i (R_i \ x \ A_i)},$$

where i denotes a facility; R_i = receipts for facility i;

A_i average heat content for receipts at facility i;
and C_i = cost in cents per million Btu for facility i.

The weighted average cost in dollars per unit (i.e., tons, barrels, or Mcf) is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{\sum_i (R_i \ x \ A_i \ x \ C_i)}{10^2 \sum_i R_i},$$

where i denotes a facility; R_i = receipts for facility i;
A_i = average heat content for receipts at facility i;
and, C_i = cost in cents per million Btu for facility i.

Power Production, Fuel Stocks, and Fuel Consumption Data. The Bureau of Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry prior to 1936. After 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the Form FPC-4. The Federal Power Act, Section 311 and 312, and FPC Order 141 defined the legislative authority to collect power production data. The Form EIA-759 replaced the Form FPC-4 in January 1982.

In 1996, the Form EIA-900 was initiated to collect sales for resale data from unregulated entities. In 1998, the form was modified to collect sales for resale, gross generation, and sales to end user data. In 1999, the form was modified to collect net generation, consumption, and ending stock data. In 2000, the form was modified to include useful thermal output data.

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. In January 2008, Form EIA-923 superseded both the EIA-906 and EIA-920 forms for the collection of these data.

Methodology to Estimate Biogenic and Non-biogenic Municipal Solid Waste. Municipal Solid Waste (MSW) consumption for generation of electric power is split into its biogenic and non-biogenic components beginning with 2001 data by the following methodology:

> The reported tonnage of MSW is reported on the Form EIA-923. The composition of MSW and categorization of the components were obtained from the Environmental Protection Agency publication, *Municipal Solid Waste in the United States: 2005 Facts and Figures.* The Btu contents of the components of MSW were obtained from various sources.[2]
>
> The potential quantities of combustible MSW discards (which include all MSW material available for combustion with energy recovery, discards to landfill, and other disposal) were multiplied by their respective Btu contents. The EPA-based categories of MSW were then classified into renewable and non-renewable groupings. From this, EIA calculated how much of the energy potentially consumed from MSW was attributed to biogenic components and how much to non-biogenic components (see Table 1 and 2, below).[3]

These values are used to allocate the net and gross generation published in the *Electric Power Monthly* and *Electric Power Annual* generation tables. The tons of biogenic and non-biogenic components were estimated with the assumption that glass and metals were removed prior to combustion. The average Btu/ton for the biogenic and non-biogenic components is estimated by dividing the total Btu consumption by the total tons. Published net generation attributed to biogenic MSW and non-biogenic MSW is classified under Other Renewables and Other, respectively.

Table 1. Btu Consumption for Biogenic and Non-biogenic Municipal Solid Waste (percent)

	2001	2002	2003	2004	2005	2006
Biogenic	57	56	55	55	56	56
Non-biogenic	43	44	45	45	44	44

Table 2. Tonnage Consumption for Biogenic and Non-biogenic Municipal Solid Waste (percent)

	2001	2002	2003	2004	2005	2006
Biogenic	77	77	76	76	75	75
Non-biogenic	23	23	24	24	25	25

Useful Thermal Output. With the implementation of the Form EIA-923, "Power Plant Operations Report," in 2008, combined heat and power (CHP) plants are required to report total fuel consumed and electric power generation4. Beginning with preliminary January 2008 data, EIA estimated the allocation of the total fuel consumed at CHP plants between electric power generation and useful thermal output.

The estimated allocation methodology is summarized in the following paragraphs. The methodology was retroactively applied to 2004-2007 data. Prior to 2004, useful thermal output was collect on the Form EIA-906 and an estimated allocation of fuel for electricity was not necessary.

[10]See the following sources:
- ◊ Bahillo, A. et al. Journal of Energy Resources Technology, "NOx and N2O Emissions During Fluidized Bed Combustion of Leather Wastes." Volume 128, Issue 2, June 2006. pp. 99-103.
- ◊ U.S. Energy Information Administration. *Renewable Energy Annual 2004*. "Average Heat Content of Selected Biomass Fuels." Washington, DC, 2005
- ◊ Penn State Agricultural College Agricultural and Biological Engineering and Council for Solid Waste Solutions. Garth, J. and Kowal, P. *Resource Recovery, Turning Waste into Energy,* University Park, PA, 1993
- ◊ Utah State University Recycling Center Frequently Asked Questions. Published at http://www.usu.edu/recycle/faq.htm. Accessed December 2006

[3] Biogenic components include newsprint, paper, containers and packaging, leather, textiles, yard trimmings, food wastes, and wood. Non-biogenic components include plastics, rubber and other miscellaneous non-biogenic waste.

First, an efficiency factor is determined for each plant and prime mover type. Based on data for electric power generation and useful thermal output (UTO) collected in 2003 (on Form EIA-906, "Power Plant Report") efficiency was calculated for each prime mover type at a plant. The efficiency factor is the total output in Btu, including electric power and useful thermal output (UTO), divided by the total input in Btu. Electric power is converted to Btu at 3,412 Btu per kilowatthour.

Second, to calculate the amount of fuel for electric power, the gross generation in Btu is divided by the efficiency factor. The fuel for UTO is the difference between the total fuel reported and the fuel for electric power generation. UTO is calculated by multiplying the fuel for UTO by the efficiency factor.

In addition, if the total fuel reported is less than the estimated fuel for electric power generation, then the fuel for electric power generation is equal to the total fuel consumed, and the UTO will be zero.

Issues within Historical Data Series

Receipts and Cost and Quality of Fossil Fuels

Values for receipts of natural gas for 2001 forward do not include blast furnace gas or other gas.

Historical data collected on FERC Form 423 and published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. However, these data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late filing issues in the FERC Form 423 data. In 2003, EIA introduced a procedure to estimate for late or non-responding entities who were required to report on the FERC Form 423. Due to the introduction of this procedure, 2003 and later data cannot be directly compared to previous years' data.

Prior to 2008, regulated plants reported receipts data on the FERC Form 423. These plants, along with unregulated plants, now report receipts data on Schedule 2 of Form EIA-923. Because FERC issued waivers to Form 423 filing requirements to some plants who met certain criteria, and because not all types of generators were required to report (only steam turbines and combined cycle units reported), a significant number of plants either did not submit fossil fuel receipts data or submitted only a portion of their fossil fuel receipts. Since Form EIA-923 does not have exemptions based on generator type, or reporting waivers, receipts data from 2008 and later cannot be directly compared to previous years' data for the regulated sector. Furthermore, there may be a notable increase in fuel receipts beginning with January 2008 data.

Also beginning with January 2008 data, tables for total receipts will include imputed quantities for plants with capacity one megawatt or more, to be consistent with other electric power data. Previous published receipts data were from plants over a 50 megawatt threshold, which was a legacy of their original collection as information for a regulatory agency, not as a survey to provide more meaningful estimates of totals for statistical purposes. Totals appeared to become smaller as more electric production came from unregulated plants, until the EIA-423 was created to help fill that gap. As a further improvement, estimation of all receipts for the universe normally depicted in the EPA (*i.e.,* one megawatt and above), with associated relative standard errors, provides a more complete assessment of the market.

Generation and Consumption

Beginning in 2008, a new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented (see above). This new methodology evenly distributes a combined heat and power (CHP) plant's losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change causes the fuel for electric power to be lower while the fuel for UTO is higher as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power between periods.

Steam Electric Plant Operational Data

Due to suspension of Form EIA-767 in 2007, there is a one year break in this data series as data year 2006 could not be collected.

Sensitive Data (Formerly identified as Data Confidentiality). Most of the data collected on the Form EIA-923 are not considered business sensitive. However, the total delivered cost of fuel delivered to nonutilities, commodity cost of fossil fuels, and reported fuel stocks at the end of the reporting period are considered business sensitive. The release of these data must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45Federal Register 59812 (1980)).

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO_2) from electric generating plants for 1989 through 2008, as well as the estimated emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from electric generating plants for 2001 through 2008. For a description of the methodology used for other years, see the technical notes to the *Electric Power Annual 2003*.

Methodology Overview

Initial estimates of uncontrolled SO_2 and NO_x emissions for all plants are made by applying an emissions factor to fuel consumption data collected by EIA on the Form EIA-923. An emission factor is the average quantity of a pollutant released from a power plant when a unit of fuel is burned, assuming no use of pollution control equipment. The basic relationship is:

Emissions = Quantity of Fuel Consumed x Emission Factor

Quantity is defined in physical units (e.g., tons of solid fuels, million cubic feet of gaseous fuels, and thousands of barrels of liquid fuels) for determining NO_x and SO_2 emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO_2 emissions.

For some fuels, the calculation of SO_2 emissions requires including in the formula the sulfur content of the fuel measured in percentage of weight. Examples include coal and fuel oil. In these cases the formula is:

Emissions = Quantity of Fuel Consumed x Emission Factor x Sulfur Content

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A1, which lists the SO_2 emission factors used for this report.

In the case of SO_2 and NO_x emissions, the factor applied to a fuel can also vary with the combustion system: either a steam-producing boiler, a combustion turbine, or an internal combustion engine. In the case of boilers, NO_x emissions can also vary with the firing configuration of a boiler and whether or not the boiler is a wet-bottom or dry-bottom design.[4] These distinctions are shown in Tables A1 and A2.

For SO_2 and NO_x, the initial estimate of uncontrolled emissions is reduced to account for the plant's operational pollution control equipment, when data on control equipment are available from the historical Form EIA-767 survey (i.e., data for the years 2005 and earlier) and the EIA-860 survey for the years 2007 and 2008. A special case for removal of SO_2 is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO_2 emission factors shown in Table A1 for fluidized bed boilers already account for 90 percent removal of SO_2 since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO_2 and NO_x emission estimates are made for all plants, in many cases the estimated emissions can be replaced with actual emissions data collected by the U.S. Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS) program. (CEMS data for CO_2 are incomplete and are not used in this report.) The CEMS data account for the bulk of SO_2 and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO_2 and NO_x emissions are employed for the limited purpose of allocating emissions by fuel, since the CEMS data itself do not provide a detailed breakdown of plant emissions by fuel. For plants for which CEMS data are unavailable, the EIA-computed values are used as the final emissions estimates.

There are a number of reasons why the historical data are periodically revised. These include data revisions, revisions in emission and technology factors, and changes in methodology. For instance, the 2008 EPA report features a revision in historic CO2 values. This revision occurred due to a change in the accepted methodology regarding adjustments made for the percentage combustion of fuels.

The emissions estimation methodologies are described in more detail below.

CO_2 Emissions. CO_2 emissions are estimated using the information on fuel consumption in physical units and the heat content of fuel collected on the Forms EIA-923 (data for combined heat and power plants) and EIA-906 (all other power plants) for the years 1989 through 2006. In 2007, a new form was introduced, the Power Plant Operations Survey (Form EIA-923), which includes information on fuel consumption previously part of the Form EIA-906/EIA-920 Surveys. Fuel consumption data from the Form EIA-923 was used to estimate CO_2. The heat content information is used to convert physical units to millions of Btu (MMBtu) consumed. To estimate CO_2 emissions, the fuel-specific emission factor from Table A3 is multiplied by the fuel consumption in MMBtu.

The estimation procedure calculates uncontrolled CO_2 emissions. CO_2 control technologies are currently in the early stages of research and there are no

[4] A boiler's firing configuration relates to the arrangement of the fuel burners in the boiler, and whether the boiler is of conventional or cyclone design. Wet and dry-bottom boilers use different methods to collect a portion of the ash that results from burning coal. For information on wet and dry bottom boilers, see the EIA Glossary at http://www.eia.doe.gov/glossary/index.html. Additional information on wet and dry-bottom-boilers and on other aspects of boiler design and operation, including the differences between conventional and cyclone designs, can be found in Babcock and Wilcox, *Steam: Its Generation and Use*, 41st Edition, 2005.

operational systems installed. Therefore, no estimates of controlled CO_2 emissions are made.

SO_2 and NO_x Emissions. To comply with environmental regulations controlling SO_2 emissions, many coal-fired generating plants have installed flue gas desulfurization (FGD) units. Similarly, NO_x control regulations require many plants to install low-NO_x burners, selective catalytic reduction systems, or other technologies to reduce emissions. It is common for power plants to employ two or even three NO_x control technologies; accordingly, the NO_x emissions estimation approach accounts for the combined effect of the equipment (Table A4). However, control equipment information is available only for plants that reported on the Form EIA-923 and for historical data from the Form EIA-767. Both the EIA-923 and the historical EIA-767 surveys are limited to plants with boilers fired by combustible fuels[5] with a minimum generating capacity of 10 megawatts (nameplate). Pollution control equipment data are unavailable from EIA sources for plants that did not report on the historical EIA-767 survey, or the EIA-923.

The following method is used to estimate SO_2 and NO_x emissions:

- For steam electric plants, uncontrolled emissions are estimated using the emission factors shown in Tables A1 and A2 as well as reported data on fuel consumption, sulfur content, and boiler firing configuration. Controlled emissions are then determined when pollution control equipment is present. Although information on control equipment was unreported for the years 2006 and 2007, updates for new installations during this period were made based upon Environmental Protection Agency data. For 2008, this data was collected on the Form EIA-923. For SO_2, the reported efficiency of the plant's FGD units is used to convert uncontrolled to controlled emission estimates. For NO_x, the reduction percentages shown in Table A4 are applied to the uncontrolled estimates.
- For plants and prime movers not reported on the historical Form EIA-767 survey or EIA-923, uncontrolled emissions are estimated using the Table A1 and Table A2 emission factors and the following data and assumptions:
  - Fuel consumption is taken from the Form EIA-923 (for historical data, from the Form EIA-920 - for combined heat and power plants) or the Form EIA-906 - all other power plants).
  - The sulfur content of the fuel is estimated from fuel receipts for the plant reported the Form EIA-923 (for historical data, from either the Form EIA-423 or the FERC Form 423). When plant-specific sulfur content data are unavailable, the national average sulfur content for the fuel, computed from the Form EIA-923 (for historical data, from the Form EIA-423 and the FERC Form 423), is applied to the plant.
  - As noted earlier, the emission factor for plants with boilers depends in part on the type of combustion system, including whether a boiler is wet-bottom or dry-bottom, and the boiler firing configuration. However, this boiler information is unavailable for steam electric plants that did not report on the historical Form EIA-767 or EIA-860. For these cases, the plant is assumed to have a dry-bottom, non-cyclone boiler using a firing method that falls into the "All Other" category shown on Table A1.[6]
  - For the plants that did not report on the historical Form EIA-767 or EIA-860, pollution control equipment data are unavailable and the uncontrolled estimates are not reduced.
- If actual emissions of SO_2 or NO_x are reported in EPA's CEMS data, the EIA estimates are replaced with the CEMS values, using the EIA estimates to allocate the CEMS plant-level data by fuel. If CEMS data are unavailable, the EIA estimates are used as the final values.

Conversion of Petroleum Coke to Liquid Petroleum

The quantity conversion is 5 barrels (of 42 U.S. gallons each) per short ton (2,000 pounds). Coke from petroleum has a heating value of 6.024 million Btu per barrel.

Relative Standard Error

The relative standard error (RSE) statistic, usually given as a percent, describes the magnitude of sampling error that might reasonably be incurred. The RSE is the square root of the estimated variance, divided by the variable of interest. The variable of interest may be the ratio of two variables, or a single variable.

[5] Boilers that rely entirely on waste heat to create steam, including the heat recovery portion of most combined cycle plants, did not report on the historical Form EIA-767 or EIA-923.

[6] The "All Other" firing configuration category includes, for example, arch firing and concentric firing. For a full list of firing method options for reporting on the historical Form EIA-767, see the form instructions, page xi, at http://www.eia.doe.gov/cneaf/electricity/forms/eia767/eia767instr.pdf.

The sampling error may be less than the nonsampling error. In fact, large RSE estimates found in preliminary work with these data have often indicated nonsampling errors, which were then identified and corrected. Nonsampling errors may be attributed to many sources, including the response errors, definitional difficulties, differences in the interpretation of questions, mistakes in recording or coding data obtained, and other errors of collection, response, or coverage. These nonsampling errors also occur in complete censuses. In a complete census, this problem may become unmanageable.

Using the Central Limit Theorem, which applies to sums and means such as are applicable here, there is approximately a 68-percent chance that the true total or mean is within one RSE of the estimated total. Note that reported RSEs are always estimates, themselves, and are usually, as here, reported as percents. As an example, suppose that a net generation from coal value is estimated to be 1,507 total million kilowatthours with an estimated RSE of 4.9 percent. This means that, ignoring any nonsampling error, there is approximately a 68-percent chance that the true million kilowatthour value is within approximately 4.9 percent of 1,507 million kilowatthours (that is, between 1,433 and 1,581 million kilowatthours). Also under the Central Limit Theorem, there is approximately a 95-percent chance that the true mean or total is within 2 RSEs of the estimated mean or total.

Note that there are times when a model may not apply, such as in the case of a substantial reclassification of sales, when the relationship between the variable of interest and the regressor data does not hold. In such a case, the new information represents only itself, and such numbers are added to model results when estimating totals. Further, there are times when sample data may be known to be in error, or are not reported. Such cases are treated as if they were never part of the model-based sample, and values are imputed.

Business Classification

Nonutility power producers consist of corporations, persons, agencies, authorities, or other legal entities that own or operate facilities for electric generation but are not required to meet all filing obligations of electric utilities to the Federal Energy Regulatory Commission. Included in this category are qualifying cogenerators, small power producer, and independent power producers. Furthermore, nonutility power producers do not have a designated franchised service area. In addition to entities whose primary business is the production and sale of electric power, entities with other primary business classifications can and do sell electric power. These can consist of manufacturing, agricultural, forestry, transportation, finance, service and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual.17 In 1997, the SIC Manual name was changed to North American Industry Classification System (NAICS). The following is a list of the main classifications and the category of primary business activity within each classification.

Agriculture, Forestry, and Fishing

111 Agriculture production-crops
112 Agriculture production, livestock and animal specialties
113 Forestry
114 Fishing, hunting, and trapping
115 Agricultural services

Mining

211 Oil and gas extraction
2121 Coal mining
2122 Metal mining
2123 Mining and quarrying of nonmetallic minerals except fuels

Construction

23

Manufacturing

311 Food and kindred products
3122 Tobacco products
314 Textile and mill products
315 Apparel and other finished products made from fabrics and similar materials
316 Leather and leather products
321 Lumber and wood products, except furniture
322 Paper and allied products (other than 322122 or 32213)
322122 Paper mills, except building paper
32213 Paperboard mills
323 Printing and publishing
325 Chemicals and allied products (other than 325188, 325211, 32512, or 325311)
32512 Industrial organic chemicals
325188 Industrial Inorganic Chemicals
325211 Plastics materials and resins
325311 Nitrogenous fertilizers
324 Petroleum refining and related industries (other than 32411)
32411 Petroleum refining
326 Rubber and miscellaneous plastic products
327 Stone, clay, glass, and concrete products (other than 32731)
32731 Cement, hydraulic
331 Primary metal industries (other than 331111 or 331312)
331111 Blast furnaces and steel mills
331312 Primary aluminum

332	Fabricated metal products, except machinery and transportation equipment
333	Industrial and commercial equipment and components except computer equipment
3345	Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
335	Electronic and other electrical equipment and components except computer equipment
336	Transportation equipment
337	Furniture and fixtures
339	Miscellaneous manufacturing industries

Transportation and Public Utilities

22	Electric, gas, and sanitary services
2212	Natural gas transmission
2213	Water supply
22131	Irrigation systems
22132	Sewerage systems
481	Transportation by air
482	Railroad transportation
483	Water transportation
484	Motor freight transportation and warehousing
485	Local and suburban transit and interurban highway passenger transport
486	Pipelines, except natural gas
487	Transportation services
491	United States Postal Service
513	Communications
562212	Refuse systems

Wholesale Trade

421 to 422

Retail Trade

441 to 454

Finance, Insurance, and Real Estate

521 to 533

Services

512	Motion pictures
514	Business services
514199	Miscellaneous services
541	Legal services
561	Engineering, accounting, research, management, and 611 Education services
622	Health services
624	Social services
712	Museums, art galleries, and botanical and zoological gardens
713	Amusement and recreation services
721	Hotels
811	Miscellaneous repair services
8111	Automotive repair, services, and parking
812	Personal services
813	Membership organizations related services
814	Private households

Public Administration

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Table A1. Sulfur Dioxide Uncontrolled Emission Factors

(Units and Factors)

Fuel, Code, Source and Emission units			Combustion System Type/Firing Configuration							
Fuel And EIA Fuel Code	**Source and Tables (As appropriate)**	**Emissions Units** (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	Cyclone Boiler	Fluidized Bed Boiler	Opposed Firing Boiler	Spreader Stoker Boiler	Tangential Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Agricultural Byproducts (AB)	Source: 1	Lbs per ton	0.08	0.01	0.08	0.08	0.08	0.08	NA	NA
Blast Furnace Gas (BFG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Bituminous Coal (BIT)*	Source: 2, Table 1.1-3	Lbs per ton	38.00	3.8	38.00	38.00	38.00	38.00	NA	NA
Black Liquor (BLQ)	Source: 1	Lbs per ton **	7.00	0.70	7.00	7.00	7.00	7.00	NA	NA
Distillate Fuel Oil (DFO)*	Source: 2, Table 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Jet Fuel (JF)*	Assumed to have emissions similar to DFO.	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Kerosene (KER)*	Assumed to have emissions similar to DFO.	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Landfill Gas (LFG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Lignite Coal (LIG)*	Source: 2, Table 1.7-1	Lbs per ton	30.00	3.00	30.00	30.00	30.00	30.00	NA	NA
Municipal Solid Waste (MSW)	Source: 1	Lbs per ton	1.70	0.17	1.70	1.70	1.70	1.70	NA	NA
Natural Gas (NG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Other Biomass Gas (OBG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Other Biomass Liquids (OBL)*	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Other Biomass Solids (OBS)	Source: 1 (including footnote 11 within source)	Lbs per ton	0.23	0.02	0.23	0.23	0.23	0.23	NA	NA
Other Gases (OG)	Source: 1 (including footnote 7 within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Other (OTH)	Assumed to have emissions similar to NG.	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Petroleum Coke (PC)*	Source: 1	Lbs per ton	39.00	3.90	39.00	39.00	39.00	39.00	NA	NA
Propane Gas (PG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Residual Fuel Oil (RFO)*	Source: 2, Table 1.3-1	Lbs per MG	157.00	15.70	157.00	157.00	157.00	157.00	NA	NA
Synthetic Coal (SC)*	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	38.00	3.8	38.00	38.00	38.00	38.00	NA	NA
Sludge Waste (SLW)	Source: 1 (including footnote 11 within source)	Lbs per ton **	2.80	0.28	2.80	2.80	2.80	2.80	NA	NA
Subbituminous Coal (SUB)*	Source: 2, Table 1.1-3	Lbs per ton	35.00	3.5	35.00	38.00	35.00	35.00	NA	NA
Tire-Derived Fuel (TDF)*	Source: 1 (including footnote 13 within source)	Lbs per ton	38.00	3.80	38.00	38.00	38.00	38.00	NA	NA
Waste Coal (WC)*	Source: 1 (including footnote 20 within source)	Lbs per ton	30.00	3.00	30.00	30.00	30.00	30.00	NA	NA
Wood Waste Liquids (WDL)*	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Wood Waste Solids (WDS)	Source: 1	Lbs per ton	0.29	0.08	0.29	0.08	0.29	0.29	NA	NA
Waste Oil (WO)*	Source: 2, Table 1.11-2	Lbs per MG	147.00	14.70	147.00	147.00	147.00	147.00	NA	NA

Note: * For these fuels, emissions are estimated by multiplying the emissions factor by the physical volume of fuel and the sulfur percentage of the fuel (other fuels do not require the sulfur percentage in the calculation). Note that EIA data do not provide the sulfur content of TDF. The value used (1.56 percent) is from U.S. EPA, *Control of Mercury Emissions from Coal-Fired Electric Utility Boilers*, April 2002, EPA-600/R-01-109, Table A-11 (available at:http://www.epa.gov/appcdwww/aptb/EPA-600-R-01-109A.pdf).

** Although Sludge Waste and Black Liquor consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., *Documentation for the 2002 Electric Generating Unit National Emissions Inventory*, Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01), Emissions, Monitoring and Analysis Division, Research Triangle Park; and
2. U.S. Environmental Protection Agency, *AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources)*; available at: http://www.epa.gov/ttn/chief/ap42/

Table A2. Nitrogen Oxides Uncontrolled Emission Factors
(Units and Factors)

Fuel, Code, Source, and Emission Units			Combustion System Type/Firing Configuration Factors for Wet-Bottom Boilers are in Brackets; All Other Boiler Factors are for Dry-Bottom							
Fuel And EIA Fuel Code	**Source and Tables (As appropriate)**	**Emissions Units** (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	Cyclone Boiler	Fluidized Bed Boiler	Opposed Firing Boiler	Spreader Stoker Boiler	Tangential Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Agricultural Byproducts (AB)	Source: 1	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20	NA	NA
Blast Furnace Gas (BFG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	15.40	15.40	15.40	15.40	15.40	15.40	30.40	256.55
Bituminous Coal (BIT)	Source: 2, Table 1.1-3	Lbs per ton	33.00	5.00	12 [31]	11.00	10.0 [14.0]	12.0 [31.0]	NA	NA
Black Liquor (BLQ)	Source: 1	Lbs per ton **	1.50	1.50	1.50	1.50	1.50	1.50	NA	NA
Distillate Fuel Oil (DFO)	Source: 2, Tables 3.4-1 & 1.3-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	122.0	443.8
Jet Fuel (JF)	Source: 2, Tables 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	118.0	432.0
Kerosene (KER)	Source: 2, Tables 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	118.0	432.0
Landfill Gas (LFG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	72.44	72.44	72.44	72.44	72.44	72.44	144.0	1215.22
Lignite Coal (LIG)	Source: 2, Table 1.7-1	Lbs per ton	15.00	3.60	6.3	5.80	7.10	6.3	NA	NA
Municipal Solid Waste (MSW)	Source: 1	Lbs per ton	5.0	5.0	5.0	5.0	5.0	5.0	NA	NA
Natural Gas (NG)	Source: 2, Tables 1.4-1, 3.1-1, and 3.4-1	Lbs per MMCF	280.00	280.00	280.00	280.00	170.00	280.00	328.00	2768.00
Other Biomass Gas (OBG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	112.83	112.83	112.83	112.83	112.83	112.83	313.60	2646.48
Other Biomass Liquids (OBL)	Source: 1 (including footnote 3 within source)	Lbs per MG	19.0	19.0	19.0	19.0	19.0	19.0	NA	NA
Other Biomass Solids (OBS)	Source: 1 (including footnote 11 within source)	Lbs per ton	2.0	2.0	2.0	2.0	2.0	2.0	NA	NA
Other Gases (OG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	152.82	152.82	152.82	152.82	152.82	152.82	263.82	2226.41
Other (OTH)	Assumed to have emissions similar to natural gas.	Lbs per MMCF	280.00	280.00	280.00	280.00	170.00	280.00	328.00	2768.00
Petroleum Coke (PC)	Source: 1 (including footnote 8 within source)	Lbs per ton	21.00	5.00	21.00	21.00	21.00	21.00	NA	NA
Propane Gas (PG)	Sources: 3; EIA estimates	Lbs per MMCF	215.00	215.00	215.00	215.00	215.00	215.00	330.75	2791.22
Residual Fuel Oil (RFO)	Source: 2, Table 1.3-1	Lbs per MG	47.00	47.00	47.00	47.00	32.00	47.00	NA	NA
Synthetic Coal (SC)	Assumed to have emissions similar to Bituminous Coal.	Lbs per ton	33.00	5.00	12 [31]	11.00	10.0 [14.0]	12.0 [31.0]	NA	NA
Sludge Waste (SLW)	Source: 1 (including footnote 11 within source)	Lbs per ton **	5.00	5.00	5.00	5.00	5.00	5.00	NA	NA
Subbituminous Coal (SUB)	Source: 2, Table 1.1-3	Lbs per ton	17.00	5.00	7.4 [24]	8.80	7.2	7.4 [24.0]	NA	NA
Tire-Derived Fuel (TDF)	Source: 1 (including footnote 13 within source)	Lbs per ton	33.00	5.00	12 [31]	11.00	10.0 [14.0]	12.0 [31.0]	NA	NA
Waste Coal (WC)	Source: 1 (including footnote 20 within source)	Lbs per ton	15.00	3.60	6.30	5.80	7.10	6.30	NA	NA
Wood Waste Liquids (WDL)	Source: 1 (including footnote 16 within source)	Lbs per MG	5.43	5.43	5.43	5.43	5.43	5.43	NA	NA
Wood Waste Solids (WDS)	Source: 1	Lbs per ton	2.51	2.00	2.51	1.50	2.51	2.51	NA	NA
Waste Oil (WO)	Source: 2, Table 1.11-2	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	NA	NA

Note: ** Although Sludge Waste and Black Liquor consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., *Documentation for the 2002 Electric Generating Unit National Emissions Inventory*, Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01); Emissions, Monitoring and Analysis Division, Research Triangle Park;
2. U.S. Environmental Protection Agency, *AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources)*; available at: http://www.epa.gov/ttn/chief/ap42/; and
3. U.S. Environmental Protection Agency, *Factor Information Retrieval (FIRE) Database, Version 6.25*; available at: http://www.epa.gov/ttn/chief/software/fire/index.html

Table A3. Carbon Dioxide Uncontrolled Emission Factors
(Pounds of CO_2 per Million Btu)

Fuel, Code, Source, and Emission Factor		
Fuel And EIA Fuel Code	**Source and Tables (As appropriate)**	**Factor (Pounds of CO_2 Per Million Btu)*** **
Bituminous Coal (BIT)	Source: 1	205.300
Distillate Fuel Oil (DFO)	Source: 1	161.386
Geothermal (GEO)	Estimate from EIA, Office of Integrated Analysis and Forecasting	16.59983
Jet Fuel (JF)	Source: 1	156.258
Kerosene (KER)	Source: 1	159.535
Lignite Coal (LIG)	Source: 1	215.400
Municipal Solid Waste (MSW)	Source: 1 (including footnote 2 within source)	91.900
Natural Gas (NG)	Source: 1	117.080
Petroleum Coke (PC)	Source: 1	225.130
Propane Gas (PG)	Source: 1	139.178
Residual Fuel Oil (RFO)	Source: 1	173.906
Synthetic Coal (SC)	Assumed to have emissions similar to Bituminous Coal.	205.300
Subbituminous Coal (SUB)	Source: 1	212.700
Tire-Derived Fuel (TDF)	Source: 1	189.538
Waste Coal (WC)	Assumed to have emissions similar to Bituminous Coal.	205.300
Waste Oil (WO)	Source: 2, Table 1.11-3 (assumes typical heat content of 4.4 MMBtus per barrel)	210.000

Note: *** CO_2 factors do not vary by combustion system type or boiler firing configuration.
Sources: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, Voluntary Reporting of Greenhouse Gases Program, *Table of Fuel and Energy Source: Codes and Emission Coefficients*; available at: http://www.eia.doe.gov/oiaf/1605/coefficients.html; and U.S. Environmental Protection Agency, *AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources)*; available at: http://www.epa.gov/ttn/chief/ap42/.

Table A4. Nitrogen Oxides Control Technology Emissions Reduction Factors

Nitrogen Oxides Control Technology	EIA-Code(s)	Reduction Factor (Percent)
Advanced Overfire Air	AA	30[1]
Alternate Burners	BF	20
Flue Gas Recirculation	FR	40
Fluidized Bed Combustor	CF	20
Fuel Reburning	FU	30
Low Excess Air	LA	20
Low NO_x Burners	LN	30[1]
Other (or Unspecified)	OT	20
Overfire Air	OV	20[1]
Selective Catalytic Reduction	SR	70
Selective Catalytic Reduction With Low Nitrogen Oxide Burners	SR and LN	90
Selective Noncatalytic Reduction	SN	30
Selective Noncatalytic Reduction With Low NO_x Burners	SN and LN	50
Slagging	SC	20

1. Starting with 1995 data, reduction factors for advanced overfire air, low NO_x burners, and overfire air were reduced by 10 percent.

Sources: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Babcock and Wilcox, Steam 41st Edition, 2005.

Table A5. Unit-of-Measure Equivalents

Unit	Equivalent	Unit
Kilowatt (kW)	1,000 (One Thousand)	Watts
Megawatt (MW)	1,000,000 (One Million)	Watts
Gigawatt (GW)	1,000,000,000 (One Billion)	Watts
Terawatt (TW)	1,000,000,000,000 (One Trillion)	Watts
Gigawatt	1,000,000 (One Million)	Kilowatts
Thousand Gigawatts	1,000,000,000 (One Billion)	Kilowatts
Kilowatthours (kWh)	1,000 (One Thousand)	Watthours
Megawatthours (MWh)	1,000,000 (One Million)	Watthours
Gigawatthours (GWh)	1,000,000,000 (One Billion)	Watthours
Terawatthours (TWh)	1,000,000,000,000 (One Trillion)	Watthours
Gigawatthours	1,000,000 (One Million)	Kilowatthours
Thousand Gigawatthours	1,000,000,000(One Billion)	Kilowatthours
U.S. Dollar	1,000 (One Thousand)	Mills
U.S. Cent	10 (Ten)	Mills

Source: U.S. Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Glossary

The Office of Coal, Nuclear, Electric And Alternate Fuel's Master Glossary contains all references used in this publication.
Please use this URL:
http://www.eia.doe.gov/cneaf/electricity/page/glossary.html