Electric Power Annual 2006

DOE/EIA-0348(2006)

Electric Power Annual 2006

October 2007

Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585

This report is only available on the Web at:
http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the U.S. Department of Energy. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy of the Department of Energy or any other organization.

Contacts

Questions of a general nature regarding this report should be directed to:

Robert Schnapp (202/586-5114)
Director, Electric Power Division
e-mail: robert.schnapp@eia.doe.gov

Publication Coordinator:
John W. Makens (202/586-4059)
e-mail: john.makens@eia.doe.gov;

Team Leader Coordinators:
Thomas J. Leckey (202/586-3548)
Annual Sales and Finance Team
e-mail: thomas.leckey@eia.doe.gov;

James Diefenderfer (202/586-2432)
Generation and Capacity Team
e-mail: james.diefenderfer@eia.doe.gov;

Dean Fennell (202/586-2462)
Monthly Sales and Finance Team
e-mail: dean.fennell@eia.doe.gov;

Questions of a specific nature should be directed to one of the following contributors:

Year-in-Review
Howard Stone (202/586-3189)
e-mail: howard.stone@eia.doe.gov;
Channele Wirman (202/586-5356)
e-mail: channele.wirman@eia.doe.gov;

Generation
Melvin E. Johnson (202/586-2898)
e-mail: melvin.johnson@eia.doe.gov;
Channele Wirman (202/586-5356)
e-mail: channele.wirman@eia.doe.gov;
Chris Cassar (202/586-5448)
e-mail: christopher.cassar@eia.doe.gov;
Ron S. Hankey (202/586-2630)
e-mail: ronald.hankey@eia.doe.gov;

Capacity
Elsie Bess (202/586-2402)
e-mail: elsie.bess@eia.doe.gov;
Kenneth McClevey (202/586-4258)
e-mail: kenneth.mcclevey@eia.doe.gov;
Glenn McGrath (202/586-4325)
e-mail: glenn.mcgrath@eia.doe.gov;

Demand, Capacity Resources, and Capacity Margins
John W. Makens (202/586-4059)
e-mail: john.makens@eia.doe.gov;

Fuel
Melvin E. Johnson (202/586-2898)
e-mail: melvin.johnson@eia.doe.gov;
Stephen R. Scott (202/586-5140)
e-mail: stephen.scott@eia.doe.gov;
Rebecca A. McNerney (202/586-4509)
e-mail: rebecca.mcnerney@eia.doe.gov;
Channele Wirman (202/586-5356)
e-mail: channele.wirman@eia.doe.gov;
Chris Cassar (202/586-5448)
e-mail: christopher.cassar@eia.doe.gov;
Ron S. Hankey (202/586-2630)
e-mail: ronald.hankey@eia.doe.gov;

Emissions
Kevin G. Lillis (202/586-3704)
e-mail: kevin.lillis@eia.doe.gov;
Natalie Ko (202/586-3139)
e-mail: natalie.ko@eia.doe.gov;

Trade
John W. Makens (202/586-4059)
e-mail: john.makens@eia.doe.gov;

Retail Customers, Sales, and Revenue
Karen McDaniel (202/586-4280)
e-mail: karen.mcdaniel@eia.doe.gov;

Revenue and Expense Statistics
Karen McDaniel (202/586-4280)
e-mail: karen.mcdaniel@eia.doe.gov;

Demand-Side Management
Karen McDaniel (202/586-4280)
e-mail: karen.mcdaniel@eia.doe.gov.

Quality

The Energy Information Administration is committed to quality products and quality service. To ensure that this report meets the highest standards for quality, please forward your comments or suggestions about this publication to Robert Schnapp at 202/586-5114, or e-mail: robert.schnapp@eia.doe.gov.

For general inquiries about energy data, please contact the National Energy Information Center at 202/586-8800. Internet users may contact the center at: infoctr@eia.doe.gov.

Preface

The Electric Power Annual 2006 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; 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 seven surveys completed annually or monthly by electric utilities and other electric power producers and submitted to the EIA and five surveys performed by other government organizations[1]. The EIA forms are described in detail in the "Technical Notes."

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

Contents

Tables

Illustrations

Electric Power Industry 2006: Year in Review

Overview

The volume of electric power generation and sales to customers rose slightly by 0.2 percent each, from 2005 to 2006. Milder summer and winter temperatures in 2006 than in 2005 dampened overall demand for electric power for heating and air conditioning. With the exception of July, more moderate average temperatures prevailed in large parts of the Nation during the summer months. Summer peak demand (noncoincident) grew to 789,475 megawatts (MW), 4.0 percent higher than the peak in 2005, and 12.1 percent higher than in 2004. Net generation of electric power during June, July and August 2006 increased by 0.9 percent from the previous summer. Winter peak demand (noncoincident), which is always smaller than summer peak demand, was 640,981 MW, growing 2.3 percent, nearly twice the rate of change from the prior year rate and surpassing the rate of growth in winter peak demand over the past several years. Net generation during the winter months (January, February and December 2006) was 1.8 percent lower than the previous year's winter months. Continuing economic growth in the Nation is reflected in the 0.7 percent growth in retail electricity sales to the commercial and industrial sectors, while the milder weather is reflected in the decline of 0.6 percent in retail electricity sales to the residential sector.

Total net summer capacity increased 0.8 percent, a net increase of 8,195 MW, almost all in the form of natural gas-fired combined-cycle units. Actual available capacity (lower than net summer capacity due to constraints from planned and forced outages and deratings) was 906,155 MW in 2006 for the electric power industry within the contiguous United States. The electrical system net internal demand[1] was 760,108 MW for the contiguous United States. The associated capacity margin rose to 16.1 percent in 2006, a slight increase over the 15.4 percent margin in 2005. Notably, the Florida Reliability Coordinating Council doubled its capacity margin, achieving a level of 17.6 percent in 2006. Retail prices for electricity increased by 9.3 percent to an average of 8.9 cents per kilowatthour. Prices increased in all regions of the country, but most of the larger increases occurred in the East. States with restructuring programs such as Maryland and Delaware had portions of their retail electricity price caps lifted in 2006, contributing to significant price hikes. Additional factors that contributed to higher retail prices include termination of long term wholesale power contracts at some utilities and rate increases that became effective due to higher delivered fuel costs over the past few years.

[1] Net internal demand is defined as internal demand less direct load control load management and interruptible demand.

In 2006, carbon dioxide, sulfur dioxide and nitrogen oxides emissions from conventional electric generation and combined heat and power plants declined. The largest reduction was in sulfur dioxide emissions, which fell 7.9 percent. It was the largest decline since the 9.2 percent reduction in 2000. Carbon dioxide emissions were reduced by 2.2 percent and nitrogen oxides emissions were reduced by 4.1 percent.

Work continued within the electric power industry and at the Federal Energy Regulatory Commission (FERC) to implement the requirements of the Energy Policy Act of 2005. This Act amended the Federal Power Act by adding Section 215, which set the responsibility for overseeing operations, developing procedures, and enforcing mandatory reliability standards in the electric power industry to a new electricity reliability organization (ERO). Section 215 requires FERC to certify the ERO and approve reliability standards proposed by the ERO. In July 2006, FERC certified the North American Electric Reliability Corporation (NERC) to be the ERO.[2] FERC also provided guidance on a pro forma Delegation Agreement between NERC and Regional Entities under which Regional Entities would have the authority to recommend reliability standards to the ERO and enforce them. In Order Nos. 693 and 693-A, the FERC approved 83 of 107 proposed Reliability Standards for which the ERO assumed enforcement responsibilities in June 2007.[3] Under this new authority FERC may undertake enforcement actions independent of the ERO, including the imposition of penalties. The FERC, under its new general oversight responsibilities, continued to examine, provide input, and approve new mandatory standards that became effective in June 2007.

Generation

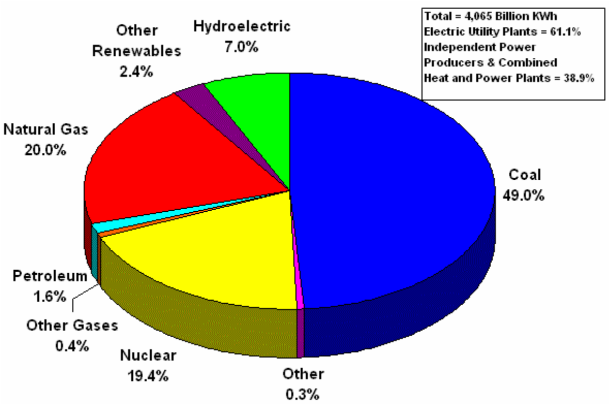
Net generation of electric power increased 0.2 percent from 2005 to 2006, rising to 4,065 million megawatthours (MWh) (Figure ES1). According to the Bureau of Economic Analysis, the U.S. real gross domestic product increased 3.4 percent in 2006, and the Federal Reserve's tally of total industrial production showed a 3.0 percent increase in 2006. Notwithstanding these indicators of robust economic activity, which normally correspond to increases in demand for electric power, milder temperatures than in the previous year contributed significantly to the

[2] North American Electric Reliability Corporation, 116 FERC ¶ 61,062 (2007) (ERO Certification Order), order on reh'g and compliance, 117 FERC ¶ 61,126 (2006).

[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007).

relatively flat rate of increase in electric power generation. According to the National Oceanic and Atmospheric Administration (NOAA), heating degree days in 2006 were 7.4 percent lower and cooling degree days were 2.1 percent lower than they were in 2005. Therefore, demand for electricity for heating and cooling purposes was lower.

Figure ES 1. U.S. Electric Power Industry Net Generation, 2006



Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report."

The three primary energy sources for generating electric power in the United States are coal, natural gas, and nuclear energy. These three sources consistently provided between 84.6 and 88.6 percent of total net generation during the period 1995 through 2006. Petroleum's share of total net generation peaked at 3.6 percent in 1998. It has declined thereafter to a low of 1.6 percent in 2006. Conventional hydroelectric power's contribution has declined from 9.3 percent in 1995 to 7.1 in 2006. Renewable energy sources, other than hydroelectric, contributed 2.4 percent of the Nation's net electric generation in 2006. Since 1995, renewable generating capacity, on average, has accounted for 2.1 percent of net generation. In that time, 2001 was the only year in which net generation by renewable resources was less than 2.0 percent of total net generation (1.9 percent).

Electricity generation from coal in 2006 fell 1.1 percent from 2005 to 1,991 million MWh. In the past decade, generation from coal declined only one other time, between 2000 and 2001. Coal's share of total net generation continued its slow decline over the past decade, from its peak of 52.8 percent in 1997 to 49.0 percent in 2006. Coal-fired plants continued to be the primary source of baseload generation. However, its share of total net generation decreased notwithstanding that total net generation increased by 0.1 percent. This was attributable to continued growth in natural gas and nuclear generation, reflecting the cumulative effects of the growth in natural gas-fired capacity and upgrades of nuclear power plants that emerged following 1997. It also reflects a reduction in net summer coal-fired generating capacity, with 967 MW retired or derated, only partially offset by 542 MW of new capacity.

The average annual growth in natural gas-fired electric power generation from 1995 to 2006 was 4.6 percent, compared to 1.4 percent average annual growth for both coal and nuclear power generation. Most of the new electric power plants placed in service in the United States since 1999 have been natural gas-fired, which are generally cleaner and more efficient than coal plants. Natural gas generation showed the highest rate of growth from 2005 to 2006 of the traditional energy sources, increasing 7.3 percent and reaching 813 million MWh. Part of the growth in 2006 was attributable to the disruption of natural gas supplies in 2005 due to Hurricanes Katrina, Rita, and Wilma, which contributed to high natural gas prices nationally, and lower natural gas electric power generation in the Gulf Coast States. By 2006, more normal conditions had returned to the region, and natural gas prices returned to a more competitive level.

Net generation at nuclear plants increased 0.7 percent in 2006 to 787 million MWh. Between 1995 and 2006, nuclear generation has ranged from an 18.0-20.6 percent share of total net generation with an annual average growth in net generation of 1.4 percent from 1995 through 2006, despite the fact that no new nuclear units have been constructed. The continued growth in nuclear generation is due to the improved capacity utilization (the capacity factors for nuclear plants have increased nearly 17.6 percentage points over the last decade) and incremental capacity upgrades to existing units. In 2006, upgrades produced 346 MW of incremental capacity and capacity factors increased from 89.3 percent in 2005 to 89.6 percent in 2006. The increase in capacity, plus improved capacity utilization, combined with the reduction in coal-fired generation contributed to the rise in nuclear generation's share of total net generation.

Net generation from conventional hydroelectric plants increased 7.0 percent over 2005, to 289 million MWh, although the level was still lower than the peak year for hydroelectric production over the past decade (356 billion kilowatthours in 1997). During the period from 1999 through 2004, the western United States experienced one of the most severe droughts in its history. Beginning in spring 2005, precipitation levels improved in the Northwest, and reservoirs began to recover, but aggregated reservoir levels were still low at year end.[4] Above average precipitation in 2006 ended the drought in the Northwest. As a result, Washington, Oregon, and Idaho, three of the major hydroelectric power producing States in the country, collectively produced 17.6 percent more hydroelectric generation than in 2005. Washington had the largest increase in conventional hydroelectric generation, increasing by 9.9 million MWh over 2005.

Petroleum-fired generation fell 47.5 percent, to 64.4 million MWh and accounted for only 1.6 percent of total net generation. Over the past decade, petroleum-fired electric power generation has declined at an average annual rate of 1.3 percent. The large decrease in 2006 is directly attributable to sustained high petroleum prices following the 50.1 percent price increase in 2005, as petroleum prices declined only 3.3 percent in 2006.

Renewable energy, other than hydroelectric, grew 10.6 percent and accounted for 2.4 percent of net generation in 2006. The greatest growth in the renewable sector was in wind generation, which contributed 95 percent of the growth in renewable energy. Wind generators produced 26.6 million MWh, 49.3 percent higher than in 2005.

Generation from other gases (refinery gases, blast furnace gas, etc.) and other miscellaneous sources accounted for the remaining net generation. Net generation from these sources increased from 28.8 million MWh in 2005 to 30.0 million MWh in 2006. The generation produced by these resources excludes the generation required by pumped-storage hydroelectric generation. In both 2005 and 2006, the net energy requirement for pumped-storage hydroelectric generation was 6.6 million MWh.

Fossil Fuel Stocks at Electric Power Plants

End-of-year coal stocks reversed the declines of the previous three years and grew to a level that was just below the total seen at the end of 2002, the highest level experienced over the past 12 years. Stocks as of December 31 totaled 141.0 million tons, 39.4 percent higher than December 31, 2005. The resumption of more normal railroad operations from mines in the Powder River Basin (PRB) of north-central Wyoming and southeastern Montana was the major factor contributing to the recovery of subbituminous coal stocks. Deliveries of coal from these mines were disrupted beginning in mid-May 2005 when two major train derailments exposed a need for immediate major maintenance on the PRB rail lines. Flooding in the region had also damaged the tracks. Extensive repair and rebuilding disrupted rail traffic flows and resulted in a shortfall in rail shipments, of as much as 15 percent below the normal level. Rail operations were disrupted throughout the entire second half of 2005, and to a lesser extent into 2006. NERC was concerned enough that the issue was placed on its "Watch List." However, as of release of the NERC's *2006/2007 Winter Assessment* in November 2006, railroad coal operations in the region were sufficient to remove the issue from the "Watch List."[5]

In 2006, inventories of petroleum increased by 3.0 percent to 51.6 million barrels by year end. Stock levels during 2004, 2005, and 2006 were lower compared to the beginning of the decade. In 2004 and 2005, this reflected the continued growth in the use of petroleum generation to meet higher summer peak demand, which limited the inventory build-up. Conversely, in 2006, the continuation of high petroleum product prices relative to pre-2005 prices contributed to both a 48.2 percent decrease in total petroleum deliveries to generators and a 47.5 percent reduction in petroleum-fired generation resulting in a modest inventory build.

Capacity

Total U.S. net summer generating capacity as of December 31, 2006 was 986,125 MW, an increase of 0.8 percent from January 1, 2006 (Figure ES2). New generating capacity added during 2006 totaled 12,129 MW, while retirements totaled 3,458 MW. Natural gas-fired generating units accounted for 8,563 MW or 70.6 percent of capacity additions. Of that amount, 7,374 MW were highly efficient combined-cycle units. Since the late 1990s, natural gas has been the fuel of choice for the majority of new generating units, resulting in a 99.0 percent increase in natural gas-fired capacity since 1999. The construction of natural gas plants began increasing in 1999, peaked during 2002 and 2003, but has since declined considerably.

[4] National Climate Data Center, "Climate of 2005 Annual Review U.S. Drought," http://www.ncdc.noaa.gov/oa/climate/research/2005/ann/drought-summary.html#regdrot and "Climate of 2006 Annual Review U.S. Drought," http://www.ncdc.noaa.gov/oa/climate/research/2006/ann/drought-summary.html#regdrot

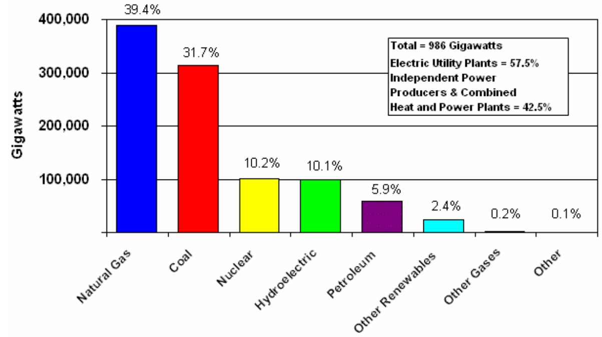
[5] Foster Electric Report, 22 November 2006, p. 17.

On December 31, 2006, natural gas-fired generating capacity represented 388,294 MW or 39.4 percent of total net summer generating capacity (Figure ES2). 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.

Petroleum-fired capacity totaled 58,097 MW, down slightly from prior year levels. This represents 5.9 percent of all generating capacity and includes approximately 31,700 MW of primarily residual oil-fired steam units located in Florida, New York, Pennsylvania, Connecticut, and Massachusetts. Gas turbines (20,300 MW of capacity) and internal combustion units (5,000 MW of capacity) account for most of the remaining petroleum-fired capacity.

Coal-fired generating capacity remained essentially unchanged at 312,956 MW or 31.7 percent of total generating capacity. This share of total capacity represents a slight decline from 2005 due to the fact that capacity additions over the past year have been primarily natural gas-fired. During 2006, 542 MW of new coal-fired generators started commercial operation, while 735 MW of older, inefficient coal-fired capacity were retired from service. The most notable addition to capacity was the 400-MW unit 3 at the Tucson Electric Power Company's Springerville facility, while the shutdown of 180 MW of capacity at NRG's C.R. Huntley facility was most notable on the retirement side. Although coal-fired capacity has not changed significantly since 1995, generation by coal-fired plants was 16.5 percent higher in 2006 than in 1995. The utilization of coal-fired generators, a measure of actual generation compared to the theoretical maximum output, has increased from 63 percent in 1995 to 73 percent in 2006. Planned coal-fired capacity on January 1, 2007, totaled 29,698 MW, up slightly from the 27,884 MW reported on January 1, 2006. Most of this proposed capacity is scheduled to start commercial operation between 2009 and 2011. Coal plants planned for Texas, Kentucky, Illinois, and Wisconsin represent over one-half of all proposed coal-fired capacity additions.

Figure ES 2. U.S. Electric Power Industry Net Summer Capacity, 2006



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

Wind plants accounted for most of the remaining new generating capacity with 2,642 MW of capacity added during 2006, considerably above the levels of 2005. Texas and Washington combined for 1,318 MW, or one-half of all new wind capacity in 2006. The Horse Hollow Wind Energy Center in Taylor County, Texas was completed during 2006. It is the largest wind facility in the Nation with a nameplate capacity of 736 MW. The increase in wind capacity for 2006 was stimulated in part by the production tax credit (PTC). The PTC, which encourages construction of wind plants, has been extended until December 31, 2007. First enacted through the Energy Policy Act of 1992 to encourage construction of wind and qualifying biomass generating facilities, the PTC has expired and been renewed several times. The most recent renewal was enacted through the Energy Policy Act of 2005. The growth in wind generating capacity is expected to continue, with over 5,000 MW of planned wind generating capacity proposed to begin operation during 2007. Texas is expected to add over 1,400 MW of wind capacity, while Colorado, Illinois, and Oregon are also expected to add a significant amount of wind capacity in 2007. The electric generating capacity from non-hydro renewable energy sources increased 13.7 percent from 2005 to 2006, due primarily to this increase in wind generating capacity.

Nuclear net summer generating capacity totaled 100,334 MW or 10.2 percent of total capacity, up slightly from 99,988 MW in 2005. This 346-MW increase in capacity was due to modifications and uprates at existing nuclear units, bringing nuclear to its highest capacity level since 1996. Conventional hydroelectric generating capacity accounted for 7.9 percent of total capacity with a summer net generating capacity of 77,821 MW. Pumped storage hydroelectric generating capacity totaled 21,461 MW. Combined, conventional and pumped storage generating capacity accounted for 10.1 percent of total capacity. Like coal and nuclear, hydroelectric generating capacity has remained relatively unchanged over the last 10 years. In 2006, there were dispersed and distributed generating units, totaling 16,678 MW of capacity.[6] This compares to compares to 9,579 in 2004, the first year for which this data was collected by EIA.

As of December 31, 2006, reported planned capacity additions that are scheduled to start commercial operation from 2007 through 2011 totaled 87,109 MW. This compares with 94,429 MW of planned capacity reported on December 31, 2005, for the 5-year period through 2010. Planned natural gas-fired capacity totaled 46,028 MW or 52.8 percent of total planned capacity additions. This compared with 56,925 MW or 60.3 percent of total planned capacity reported as of December 31, 2005.

Figure ES3 compares average capacity factors by energy source. As expected, nuclear and coal-fired generation have the highest average capacity factors at 89.6 percent and 72.6 percent, respectively. This is consistent with the economies of scale that these forms of capital intensive and energy efficient generation provide to serve energy requirements. Accordingly, coal and nuclear capacity serve baseload energy requirements, which are reflected by higher average capacity factors relative to other forms of generation. The 72.6 percent average capacity factor for coal-fired generation reflects a modest decrease from the 73.3 percent value achieved in 2005. Notwithstanding, it is well above the 62.7 percent average capacity factor experienced in 1995, and slightly above the 72.0 percent five year average (2002 to 2006). The average capacity factor for nuclear generation increased a modest 0.3 percentage points to 89.6 percent. This compares to the 89.5 percent average over the past five years and the low of 72.0 percent in 1997. The five year average capacity factors for coal and nuclear generation relative to historical improvements dating back to 1995 suggests that the industry may be reaching a plateau in terms of efficiencies gained through improved maintenance practices, and in the case of nuclear, reducing the length of refueling outages.

Because of the influx of new combined cycle natural gas generation prior to the significant and sustained price increase that occurred in 2003, average capacity factors for natural gas are calculated for both combined cycle generation and simple cycle natural gas generation.[7] In 2006, combined cycle generating capacity totaled 183,987 MW and supplied 621,162,311 MWh of net generation. This equates to a 38.5 percent average capacity factor. Simple cycle generating capacity totaled 204,307 MW with associated net generation of 191,881,236 MWh. The average capacity factor for simple cycle natural gas-fired generation was 10.7 percent. These results are consistent with the greater efficiency associated with combined cycle generation, which allows it to be dispatched to serve the intermediate portion of utilities' load curve.

The more recent emphasis placed on wind capacity, which is not a dispatchable resource, is reflected in the reduced performance of renewable resources in aggregate as measured by a composite capacity factor. Renewable generation other than hydroelectric had a 45.6 percent capacity factor in 2006. In 1999, the average capacity factor for other renewable generation was 59.3 percent. Thereafter, it has declined every year. The lower capacity factor for this class of generation relative to baseload generation is consistent with the natural replenishment but limited flow of renewable energy sources. For example, the availability of wind generation is a function of prevailing wind levels. As a result, it is not conducive to continuous dispatch, as compared to solid and liquid fuel biomass generation (e.g., landfill gas, municipal solid waste, black liquor and wood waste solids). Moreover, the addition of wind generating capacity has surpassed all other forms of renewable generation. Between 2000 and 2006, net summer capability of

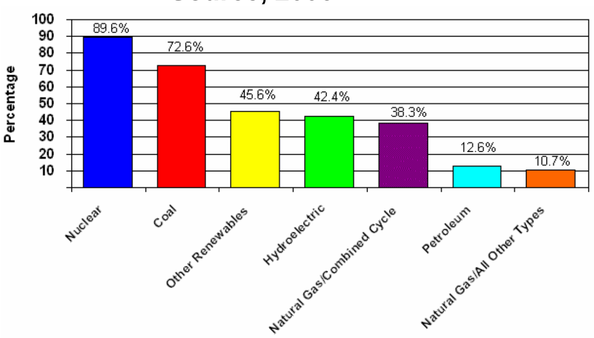
[6] Dispersed and distribute generators are commercial and industrial generators. Dispersed generators are not connected to the grid. Distributed generators are connected to the grid. Both types of generators may be installed at or near a customer's site, or at other locations, and both types of generators may be owned by either the customers of the distribution utility or by the utility. This data is collected at the distribution utility level on the Form EIA-861.

[7] The data required to average capacity factors for combined cycle and simple cycle natural gas-fired generation was obtained from plant-specific capacity and energy data from the Form EIA-860, Form EIA-906 and Form EIA-920.

wind generating capacity increased from 2,302 MW to 11,351 MW. Of this capacity, 2,631 MW was placed in service during 2006. During this same period, solid and liquid biomass generation increased from 3,591 MW to 7,858 MW. Therefore, by 2006, the near 6-fold increase resulted in wind capacity exceeding the total amount of installed solid and liquid biomass capacity by 3,493 MW.[8]

Conventional hydroelectric generation had an average capacity factor of 42.4 percent in 2006. Like other renewable resources, conventional hydroelectric generation is limited by the replenishment of water. The 42.4 percent average capacity factor realized in 2006 is consistent with the 42.6 percent average capacity factor between 1995 and 2006.

Figure ES 3. Average Capacity Factor by Energy Source, 2006



Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report."

Fuel Switching Capacity

The total amount of net summer capacity reporting natural gas as the primary fuel was 388,294 megawatts, of which 122,124 MW (31.5 percent) reported a current operational capability to switch to fuel oil as an alternative fuel. This means that the capacity had in working order all necessary equipment, including fuel storage, to switch from gas to petroleum-fired operation. However, most of this capacity is subject to environmental regulatory limits on the use of oil, such as restrictions on how many hours per year a unit is allowed to burn oil. Of the 122,124 MW of gas-fired capacity that reported the ability to switch to oil, only 32,031 MW (26.2 percent) reported no environmental regulatory constraints on oil-fired operations.

"Switchable" capacity is spread across the major generating technologies. Combustion turbine peaking units account for 42.3 percent (51,636 MW) of this capacity. Steam-electric generators (33,470 MW) and combined cycle units (36,139 MW) account for 27.4 percent and 29.6 percent, respectively. Internal combustion engines make up the remaining 0.7 percent. Of the steam-electric capacity that is capable of switching from natural gas to petroleum, which tends to be comprised of older units, almost half of the capacity had no reported environmental regulatory restrictions on petroleum-fired operations. In contrast, only 22.4 percent of the combustion turbine capacity and 11.0 percent of the combined-cycle capacity that are capable of switching fuels report no environmental regulatory restrictions on petroleum-fired operations.

The data show that most of the new natural gas-fired capacity added at the beginning of this decade cannot use oil as a backup or alternative fuel. During the period 2000 to 2006 total natural gas-fired net summer capacity increased from 219,590 MW to 388,294 MW, a gain of 168,704 MW. However, during this same period the amount of gas-fired capacity that can switch to petroleum increased by only 45,367 MW, equivalent to about 26.9 percent of the increase in total natural gas-fired capacity. About 39 percent of the capacity capable of switching from natural gas to petroleum was built prior to 1980 and close to two-thirds was built prior to 2000.

Interconnection Costs

During 2006, 275 generators representing a total nameplate capacity of 13,152 MW were connected for the first time to the electric grid. The interconnection costs are presented by producer type (Table 2.12) and by distribution, subtransmission and transmission voltage class (Table 2.13). Total cost for individual generator interconnection varies based on its components. The components of the total cost may vary based on whether or not an interconnection infrastructure was already in place, and the type of equipment for which costs were incurred, along with other factors associated with the 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 was significantly greater due in part to the interconnection of several large wind plants. Typically sited in relatively remote locations, wind plants usually require the construction of longer transmission line extensions to the plant sites than might be required for conventional power plants.

[8] Source: Form EIA-860 for the years 2000, 2005 and 2006.

Fuel Costs

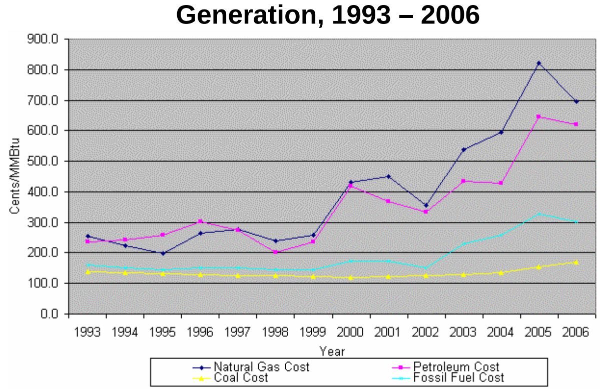
The 2006 average delivered cost for all fossil fuels used at electric power plants (coal, petroleum, and natural gas combined) for electricity generation was \$3.02 per MMBtu (Figure ES4) as compared to \$3.25 per MMBtu in 2005, a decline of 7.1 percent. The decline was attributable to a decrease in the cost of petroleum and natural gas. The cost of petroleum decreased 3.3 percent, while natural gas prices decreased 15.5 percent, notwithstanding the 8.0 percent increase in deliveries to natural gas-fired generators. The decline in the demand and delivered price of petroleum, the increase in natural gas deliveries and the decline in natural gas prices reflect the restoration of natural gas production and transportation infrastructure following hurricanes Katrina and Rita in August and September 2005. Therefore, petroleum-fired generation declined as natural gas supplanted petroleum as the primary fuel for use in dual fuel capacity.

The cost of natural gas at electric power plants in 2006 was \$6.94 per MMBtu, 15.5 percent less than the 2005 cost of \$8.21 per MMBtu, but still 16.4 percent above the 2004 cost of \$5.96 per MMBtu, and 94.9 percent above 2002 when the cost was \$3.56 per MMBtu. The fluctuations in natural gas prices are attributable to several causes. The demand for natural gas continues to expand in the electric power industry with increasing natural gas capacity. Disruptions in natural gas production in and around the Gulf of Mexico caused by hurricanes Katrina, Rita and Wilma in 2005 drove prices up to an all-time high of \$8.21 per MMBtu. Prices began to drop at the beginning of 2006 as the gas industry recovered from these adverse weather events. An increase in domestic production in 2006, less demand during the mild winter of 2006, and record amounts of natural gas injected into storage to replenish stocks, all contributed to robust supply during 2006. The supply was more than adequate to meet demand, and despite a hot summer with record temperatures in July driving up consumption of natural gas to meet peak summer demands, the annual average cost in 2006 was lower than 2005's peak level.

The cost of petroleum somewhat mirrored the cost of natural gas. The 2006 cost of petroleum was \$6.23 per MMBtu, a 3.3 percent decrease from the 2005, but a 45.2 percent increase from 2004 and an 86.5 percent increase from 2002. These fluctuations since 2002 were due to the effects of hurricanes disrupting production and supply (in 2005) and rising prices in the world oil market due mainly to increased demand from developing Nations. In 2006, several U.S. refineries were still shut down or operated at reduced output because of hurricane damage sustained in 2005. Others began maintenance schedules that had been deferred from the previous fall. The reduction in petroleum supply led to fuel switching at electric power plants, mostly to natural gas, as a result of higher peak electricity demand in the summer. Although the average cost of natural gas was higher than petroleum on a dollar per MMBtu basis (\$6.94 versus \$6.23), the higher thermal efficiency realized by burning natural gas, measured by heat rates (see Table A6 for average heat rates by prime mover and fuel-type) favored the use of natural gas over petroleum in fuel switchable combined cycle generation.

Coal is the only fossil fuel that has continued to increase in cost at electric plants each year since 2000. The 2006 delivered cost was 9.7 percent higher than 2005, 24.3 percent higher than 2004, and 40.8 percent higher than in 2000 when the trend began (Figure ES 4.). Increasing delivered coal costs are the result of several factors. New safety regulations requiring retro-fitting of mining equipment, higher taxes on coal extraction, and higher cost for diesel fuel (used for production and transportation) all contributed to the producers' increase in coal prices. Coal-fired electricity generators also faced new rail fuel surcharges as well as numerous increases in transportation costs as contract rollovers escalated the delivery price for new contracts.

Figure ES 4. Fuel Costs for the Electricity Generation, 1993 – 2006



Sources: 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."

Emissions

The carbon dioxide, sulfur dioxide and nitrogen oxides emissions estimates for electricity are based on the fossil fuels consumed by electric power plants for electric power generation, and fossil fuels consumed by combined heat and power plants for the generation of electric power and useful thermal output. In addition to the new 2006 estimates, the emissions estimates for carbon dioxide have been revised back to 1995. The revisions are primarily due to updates to the emissions factors used in the estimation methodology (See the discussion of Air Emissions in the Technical Notes and, in particular, Tables A1, A2, and A3).

Estimated carbon dioxide emissions by U.S. electric generators and combined heat and power facilities decreased by 2.2 percent from 2005 to 2006 (from 2,514 million metric tons to 2,460 million metric tons). This was the first decrease reported since 2001. The decline reflects both the decrease in total net generation of electric power from fossil fuels and the changes in the contribution of each fossil fuel to electric power generation in the United States. Coal consumption declined 1.1 percent, while petroleum consumption declined 43.3 percent. Consumption of natural gas, which contributes the least amount of carbon dioxide per Btu consumed, rose by 5.6 percent in 2006. Overall, electric power generation by these three fossil fuels fell 0.9 percent from 2005 to 2006.

Estimated emissions of nitrogen oxides and sulfur dioxide also declined between 2005 and 2006. Nitrogen oxides emissions dropped by 4.1 percent (from 3.961 to 3.799 million metric tons). Sulfur dioxide emissions decreased by 7.9 percent (from 10.340 to 9.524 million metric tons).

Emissions trends followed the use of fossil fuels and the impacts of Federal and State pollution control regulations on power plant operations. One factor is the increase in required installations of new pollution control equipment. For example, coal-fired generating capacity with equipment for removing sulfur dioxide (flue gas desulfurization units, also referred to as scrubbers) increased by 26.1 percent between 1994 and 2005, from 80.6 to 101.6 gigawatts, covering 32.5 percent of total coal-fired capacity. Another factor affecting emission decreases is changes in fuel mix, particularly the increased use of subbituminous coal. Many plants have switched from bituminous coal to subbituminous coal which emits less sulfur dioxide and nitrogen oxides when burned due to the relatively low sulfur content and low combustion temperature associated with subbituminous coal.

Trade

Total wholesale purchases of electric power in the United States declined in 2006 for the third straight year to 5,503 million MWh, a 9.7 percent reduction. Almost half the volume of wholesale sales is provided by energy-only providers, or power marketing companies, a class of electric entities, authorized by FERC to transact at market based rates, that came into being during the late 1990s with the deregulation of the wholesale power markets. However, total sales volumes from wholesale power marketers have declined dramatically from 5,757 million MWh in 2002 to 2,446 million MWh in 2006, and their market share has declined from over 67.2 percent to 44.5 percent over the same period. Between 2004 and 2006, capacity margins declined from 20.9 percent to 16.1 percent. In tighter capacity markets, utilities with retail native load and wholesale requirements service obligations have less surplus capacity and energy available to engage in off-system sales with third parties. Correspondingly, all of the traditional electric utility ownership classes have increased their market share of wholesale sales notwithstanding that their sales volumes have held steady. Traditional utilities tend to have longer term contracts, providing sales volume stability. The number of power marketing companies participating in wholesale markets has shrunk from 2002 to 2006. This is the result of fewer sales and reduced margins for the marketing companies. Independent power producers continue to provide an increasing share of the volume, reaching 24.1 percent in 2006.

The Nation's only international trade in electric power is with Canada and Mexico, and nearly all the trade is conducted with Canada. Most Mexican electric power trade is done with the State of California, while transactions with Canada are conducted through several large transmission corridors located in the Pacific Northwest, the Northern Plains, and New England. Much of the electricity provided from Canada is hydroelectric generation available for sale because of heavy seasonal river flows.

Total international net imports of electric power declined from about 24.7 million MWh in 2005 to about 18.4 million MWh in 2006, consistent with weak demand growth in the United States. Canadian sales to the United States declined from 42.9 million MWh in 2005 to 41.5 million MWh in 2006, and U.S. exports to Canada increased by 21.1 percent. Overall, total U.S. imports declined to 42.7 million MWh from 44.5 million MWh in 2005, and total exports grew to 24.3 million MWh from 19.8 million MWh in 2005.

Revenue and Expense Statistics

In 2006, major investor-owned electric utility operating revenues (from sales to ultimate customers, sales for resale, and other electric income) were $277 billion, a

3.6 percent increase from 2005. Operating expenses in 2006 stayed in line with revenue growth, also increasing 3.6 percent, to $247 billion. Net income in 2006 was $29.9 billion, a slight increase over the $28.9 billion of net income realized in 2005.

Increases in operating expenses were driven by increasing delivered fuel costs (up about 6 percent) and increases in "other" production costs[9] (up about $3.8 billion). Unlike 2005, purchased power expenses were held in check, increasing only slightly over 2005 levels. Transmission expenses increased for the fifth consecutive year and have more than doubled since 2001, averaging a 21.2 percent annual increase over that period. Distribution expenses, however, remained flat in 2006, increasing only slightly from 2005, while averaging only a 2.6 percent annual increase since 2001. Average operating expenses for fuel at investor-owned fossil steam plants posted another significant increase in 2006, rising 8.8 percent to 3.2 mills per kilowatthour (kWh). Average operation expenses at all plants other than hydroelectric increased, as did average maintenance expenses.

Electricity Prices and Sales

In 2006, the average retail price for all customers rose to 8.9 cents per kWh, a sharp increase of three-fourths of a cent from the 2005 price level. The 9.3 percent increase was the largest since 1981.

Fourteen States and the District of Columbia saw the average price of electricity rise by 10 percent or more from 2005 to 2006. Prices increased in all regions of the country but most of the larger increases occurred in the East. Another 14 States saw increases between 5 and 10 percent between 2005 and 2006. States with restructuring programs such as Maryland and Delaware had portions of their retail electricity price caps lifted in 2006, contributing to significant price hikes.

Residential prices increased to 10.4 cents per kWh, almost a cent, or 10.1 percent, between 2005 and 2006. Average residential prices rose sharply in the New England and West South Central Census Divisions as Connecticut and Texas had large price increases for the second year in a row. Delaware had the highest average residential price increase at almost 30 percent.

Average industrial prices increased to 6.2 cents per kWh, or 7.5 percent above 2005. Average commercial prices increased to 9.5 cents per kWh, a 9.1 percent increase. In Texas, where the largest volume of industrial sales on a State level occurs, industrial prices increased almost 10 percent. About two-thirds of the industrial market in Texas is now served by energy service providers. Of the remaining one-third, investor-owned utilities served 17.1 percent; distribution cooperatives served 7.5 percent, and municipal utilities 6.2 percent. In the six New England States, average industrial prices increased more than 28 percent.

Total retail sales of electricity in 2006 were 3,670 million MWh. Annual growth in electricity sales in 2006 was 0.2 percent, showing virtually no growth compared with the 1.8 percent average annual growth since 1995. Sales to the residential sector decreased by 0.6 percent from 2005 to 2006. This marks only the second time residential sales decreased since 1974. Sales to the commercial sector increased by 1.9 percent, and sales to the industrial sector decreased 0.8 percent. Total retail sales increased by more than 5 percent in five States, led by West Virginia, which showed a 7.2 percent increase. Sales fell in 18 States, including both Maryland and New York where sales decreased by over 5 percent.

In the last few years, some States have encouraged utilities to adopt customer service programs which respond to growing concerns about the environment, electricity reliability, and the rising cost of providing electricity. Green pricing programs allow consumers to purchase electricity generated from wind and other renewable sources and pay for renewable energy development. Customers subscribing to green pricing programs increased steadily between 2002 and 2005. In 2006 however, 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.

Net metering programs allow consumers with onsite generators to send excess generation to the grid and receive credit for that energy on their bill. The number of customers in these programs has been steadily increasing. In 2002 there were 4,472 customers in net metering programs; in 2006 there were more than 34,000 customers. Seventy-five percent of these net metering customers are in California. Despite the growth of green pricing and net metering customers over the past few years, the total number of customers in both programs is still less than 1 percent of the national total.

[9] System control and load dispatching, and other expenses not associated with purchased power.

Demand-Side Management

In 2006, electricity providers reported total peak-load reductions of 27,240 MW resulting from demand-side management (DSM) programs, a 6.0 percent increase from the amount reported in 2005. Reported DSM costs increased to $2.1 billion, a 6.7 percent increase from costs reported in 2005. 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. However, DSM costs and program benefits have tracked consistently in the last 4 years. Nominal DSM expenditures have increased significantly since 2003, averaging 16.5 percent average annual growth over the period. Actual peak load reductions have improved by an annual average of 5.9 percent, while energy savings have risen 8.3 percent on average since 2003. New pricing programs designed to deliver real-time signals to consumers may account for some of the recent cost increases and improved efficiency over the last several years.

Table ES1. Summary Statistics for the United States, 1995 through 2006

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Net Generation (thousand megawatthours)												
Coal[1]	1,990,926	2,013,179	1,978,620	1,973,737	1,933,130	1,903,956	1,966,265	1,881,087	1,873,516	1,845,016	1,795,196	1,709,426
Petroleum[2]	64,364	122,522	120,771[R]	119,406	94,567	124,880	111,221	118,061	128,800	92,555	81,411	74,554
Natural Gas	813,044	757,974	708,854[R]	649,908	691,006	639,129	601,038	556,396	531,257	479,399	455,056	496,058
Other Gases[3]	16,060	16,317	16,766	15,600	11,463	9,039	13,955	14,126	13,492	13,351	14,356	13,870
Nuclear	787,219	781,986	788,528	763,733	780,064	768,826	753,893	728,254	673,702	628,644	674,729	673,402
Hydroelectric Conventional[4]	289,246	270,321[R]	268,417	275,806	264,329	216,961	275,573	319,536	323,336	356,453	347,162	310,833
Other Renewables[5]	96,423	87,213[R]	82,604[R]	79,487[R]	79,109[R]	70,769[R]	80,906	79,423	77,088	77,183	75,796	73,965
Pumped Storage[6]	-6,558	-6,558	-8,488	-8,535	-8,743	-8,823	-5,539	-6,097	-4,467	-4,040	-3,088	-2,725
Other[7]	13,977	12,468[R]	14,483[R]	14,045[R]	13,527[R]	11,906[R]	4,794	4,024	3,571	3,612	3,571	4,104
All Energy Sources	**4,064,702**	**4,055,423[R]**	**3,970,555**	**3,883,185**	**3,858,452**	**3,736,644**	**3,802,105**	**3,694,810**	**3,620,295**	**3,492,172**	**3,444,188**	**3,353,487**
Net Summer Generating Capacity (megawatts)												
Coal[1]	312,956	313,380	313,020	313,019	315,350	314,230	315,114	315,496	315,786	313,624	313,382	311,386
Petroleum[2]	58,097	58,548	59,119	60,730[R]	59,651[R]	66,162[R]	61,837[R]	60,069[R]	66,282[R]	72,463[R]	72,518[R]	66,622[R]
Natural Gas[8]	388,294	383,061	371,011	355,442[R]	312,512[R]	252,832[R]	219,590[R]	195,119[R]	180,288[R]	176,471[R]	174,135[R]	174,482[R]
Other Gases[3]	2,256	2,063	2,296	1,994	2,008	1,670	2,342	1,909	1,520	1,525	1,664	1,661
Nuclear	100,334	99,988	99,628	99,209	98,657	98,159	97,860	97,411	97,070	99,716	100,784	99,515
Hydroelectric Conventional[4]	77,821	77,541	77,641	78,694	79,356	78,916	79,359	79,393	79,151	79,415	76,437	78,562
Other Renewables[9]	24,113	21,205[R]	18,717[R]	18,153[R]	16,710[R]	16,101[R]	15,572	15,942	15,444	15,351	15,309	15,300
Pumped Storage[10]	21,461	21,347	20,764	20,522	20,371	19,664	19,522	19,565	19,518	19,310	21,110	21,387
Other[11]	882	887[R]	746[R]	684[R]	686[R]	519[R]	523	1,023	810	774	550	550
All Energy Sources	**986,215**	**978,020**	**962,942**	**948,446**	**905,301**	**848,254**	**811,719**	**785,927**	**775,868**	**778,649**	**775,890**	**769,463**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	760,108	746,470	692,908	696,752	696,376	674,833	680,941	653,857	638,086	618,389	602,438	589,860
Capacity Resources (megawatts)	906,155	882,125	875,870	856,131	833,380	788,990	808,054	765,744	744,670	737,855	730,376	727,481
Capacity Margins (percent)	16.1	15.4	20.9	18.6	16.4	14.5	15.7	14.6	14.3	16.2	17.5	18.9
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	1,035,346	1,045,878	1,026,018	1,014,058	987,583	972,691	994,933	949,802	946,295	931,949	907,209	860,594
Petroleum (thousand barrels)[2]	115,370	211,256	209,508	206,653	168,597	216,672	195,228	207,871	222,640	159,715	144,626	132,578
Natural Gas (millions of cubic feet)	6,869,624	6,486,761	6,116,574	5,616,135	6,126,062	5,832,305	5,691,481	5,321,984	5,081,384	4,564,770	4,312,458	4,737,871
Other Gases (millions of Btu)[3]	181,081	176,906	186,796	156,306	131,230	97,308	125,971	126,387	124,988	119,412	158,560	132,520
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	18,437	19,402	18,779	17,720	17,561	18,944	20,466	20,373	20,320	21,005	20,806	20,418
Petroleum (thousand barrels)[2]	15,636	19,937	19,856	17,939	14,811	18,268	22,266	26,822	28,845	28,802	27,873	25,562
Natural Gas (millions of cubic feet)	549,335	541,206	610,105	721,267	860,019	898,286	985,263	982,958	949,106	868,569	865,774	834,382
Other Gases (millions of Btu)[3]	160,048	171,406	167,273	137,837	146,882	166,161	230,082	223,713	208,828	187,680	187,290	180,895
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	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	928,015	881,012
Petroleum (thousand barrels)[2]	131,005	231,193	229,364	224,593	183,408	234,940	217,494	234,694	251,486	188,517	172,499	158,140
Natural Gas (millions of cubic feet)	7,418,959	7,027,967	6,726,679	6,337,402	6,986,081	6,730,591	6,676,744	6,304,942	6,030,490	5,433,338	5,178,232	5,572,253
Other Gases (millions of Btu)[3]	341,129	348,312	354,069	294,143	278,111	263,469	356,053	350,100	333,816	307,092	345,850	313,415
Stocks at Electric Power Sector Facilities (year end)												
Coal (thousand tons)[12]	140,964	101,137	106,669	121,567	141,714	138,496	102,296	141,604	120,501	98,826	114,623	126,304
Petroleum (thousand barrels)[13]	51,583	50,062	51,434	53,170	52,490	57,031	40,932	54,109	56,591	51,138	48,146	50,821
Receipts of Fuel at Electricity Generators[14]												
Coal (thousand tons)[1]	1,079,943	1,021,437	1,002,032	986,026	884,287	762,815	790,274	908,232	929,448	880,588	862,701	826,860
Petroleum (thousand barrels)[2]	100,965	194,733	186,655	185,567	120,851	124,618	108,272	145,939	181,276	128,749	113,678	89,908
Natural Gas (millions of cubic feet)[15]	6,675,246	6,181,717[R]	5,734,054	5,500,704	5,607,737	2,148,924	2,629,986	2,809,455	2,922,957	2,764,734	2,604,663	3,023,327
Cost of Fuel at Electricity Generators (cents per million Btu)[13]												
Coal[1]	169	154	136	128	125	123	120	122	125	127	129	132
Petroleum[2]	623	644	429	433	334	369	418	236	202	273	303	257
Natural Gas[15]	694	821	596	539	356	449	430	257	238	276	264	198
Emissions (thousand metric tons)												
Carbon Dioxide (CO_2)	2,459,800	2,513,609	2,456,934	2,415,680	2,395,048	2,389,745	2,441,722[R]	2,338,660[R]	2,324,139[R]	2,232,709[R]	2,161,258[R]	2,083,509[R]
Sulfur Dioxide (SO_2)	9,524	10,340	10,309	10,646	10,881	11,174	11,297	12,444	12,509	13,520	12,906	11,896
Nitrogen Oxides (NO_X)	3,799	3,961	4,143	4,532	5,194	5,290	5,380	5,732	6,237	6,324	6,282	7,885
Trade (million megawatthours)												
Purchases	5,503	6,092[R]	6,570[R]	6,980[R]	8,755[R]	7,555[R]	2,346	2,040	2,021	1,966	1,798	1,618
Sales for Resale	5,493	6,072[R]	6,330[R]	6,921[R]	8,569[R]	7,345[R]	2,355	1,998	1,922	1,839	1,656	1,495
Electricity Imports and Exports (thousand megawatthours)												
Imports	42,691	44,527	34,210	30,390	36,779	38,500	48,592	43,215	39,513	43,031	43,497	42,854
Exports	24,271	19,803	22,898	23,972	15,796	16,473	14,829	14,222	13,656	8,974	3,302	3,623
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	122,471	120,761	118,764	117,280	116,622	114,890	111,718	110,383	109,048	107,066	105,343	103,917
Commercial	17,172	16,872	16,607	16,550	15,334	14,867	14,349	14,074	13,887	13,542	13,181	12,949
Industrial	760	734	748	713	602	571	527	553	540	563	586	581
Transportation	1	1	1	1	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	1,067	1,030	974	935	933	952	894	882
All Sectors	140,404	138,367	136,119	134,544	133,624	131,359	127,568	125,945	124,408	122,123	120,004	118,330

See end of table for Notes and Sources.

Table ES1. Summary Statistics for the United States, 1995 through 2006 (Continued)

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Retail Sales and Revenue Data – Bundled and Unbundled (Continued)												
Sales to Ultimate Customers (thousand megawatthours)												
Residential	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	1,082,512	1,042,501
Commercial	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	887,445	862,685
Industrial	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	1,033,631	1,012,693
Transportation	7,358	7,506	7,224	6,810	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	105,552	113,174	109,496	106,952	103,518	102,901	97,539	95,407
All Sectors	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	3,101,127	3,013,287
Direct Use[16]	146,927	150,016[R]	168,470	168,295	166,184	162,649	170,943	171,629	160,866	156,239	152,638	150,677
Total Disposition	3,816,845	3,810,984[R]	3,715,949	3,662,029	3,631,650	3,557,107	3,592,357	3,483,716	3,425,097	3,301,849	3,253,765	3,163,963
Revenue From Ultimate Customers (million dollars)												
Residential	140,582	128,393	115,577	111,249	106,834	103,158	98,209	93,483	93,360	90,704	90,503	87,610
Commercial	122,914	110,522	100,546	96,263	87,117	85,741	78,405	72,771	72,575	70,497	67,829	66,365
Industrial	62,308	58,445	53,477	51,741	48,336	50,293	49,369	46,846	47,050	47,023	47,536	47,175
Transportation	702	643	519	514	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	7,124	8,151	7,179	6,796	6,863	7,110	6,741	6,567
All Sectors	326,506	298,003	270,119	259,767	249,411	247,343	233,163	219,896	219,848	215,334	212,609	207,717
Average Retail Price (cents per kilowatthour)												
Residential	10.40	9.45	8.95	8.72	8.44	8.58	8.24	8.16	8.26	8.43	8.36	8.40
Commercial	9.46	8.67	8.17	8.03	7.89	7.92	7.43	7.26	7.41	7.59	7.64	7.69
Industrial	6.16	5.73	5.25	5.11	4.88	5.05	4.64	4.43	4.48	4.53	4.60	4.66
Transportation	9.54	8.57	7.18	7.54	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	6.75	7.20	6.56	6.35	6.63	6.91	6.91	6.88
All Sectors	8.90	8.14	7.61	7.44	7.20	7.29	6.81	6.64	6.74	6.85	6.86	6.89
Revenue and Expense Statistics (million dollars)												
Major Investor Owned												
Utility Operating Revenues	277,142	267,534	240,318	226,227	219,389	267,525	235,336	214,160	218,175	215,083	207,459	199,967
Utility Operating Expenses	247,170	238,590	207,161	197,459	188,745	235,198	210,324	182,258	186,498	182,796	173,920	165,321
Net Utility Operating Income	29,972	28,944	33,158	28,768	30,644	32,327	25,012	31,902	31,677	32,286	33,539	34,646
Major Publicly Owned (with Generation Facilities)												
Operating Revenues	NA	NA	NA	33,906	32,776	38,028	31,843	26,767	26,155	25,397	24,207	23,473
Operating Expenses	NA	NA	NA	29,637	28,638	32,789	26,244	21,274	20,880	20,425	19,084	18,959
Net Electric Operating Income	NA	NA	NA	4,268	4,138	5,238	5,598	5,493	5,275	4,972	5,123	4,514
Major Publicly Owned (without Generation Facilities)												
Operating Revenues	NA	NA	NA	12,454	11,546	10,417	9,904	9,354	8,790	8,586	8,582	8,435
Operating Expenses	NA	NA	NA	11,481	10,703	9,820	9,355	8,737	8,245	8,033	8,123	7,979
Net Electric Operating Income	NA	NA	NA	974	843	597	549	617	545	552	459	457
Major Federally Owned												
Operating Revenues	NA	NA	NA	11,798	11,470	12,458	10,685	10,186	9,780	8,833	9,082	8,743
Operating Expenses	NA	NA	NA	8,763	8,665	10,013	8,139	7,775	7,099	5,999	6,390	6,162
Net Electric Operating Income	NA	NA	NA	3,035	2,805	2,445	2,546	2,411	2,681	2,834	2,692	2,581
Major Cooperative Borrower Owned												
Operating Revenues	NA	34,088	30,650	29,228	27,458	26,458	25,629	23,824	23,988	23,321	24,424	24,609
Operating Expenses	NA	31,209	27,828	26,361	24,561	23,763	22,982	21,283	21,223	20,715	23,149	21,741
Net Electric Operating Income	NA	2,879	2,822	2,867	2,897	2,696	2,647	2,541	2,764	2,606	2,872	2,868
Demand-Side Management (DSM) Data												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction	27,240	25,710	23,532	22,904	22,936	24,955	22,901	26,455	27,231	25,284	29,893	29,561
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328
Load Management	865	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989	2,093
DSM Cost (million dollars)												
Total Cost	2,051	1,921	1,557	1,297	1,626	1,630	1,565	1,424	1,421	1,636	1,902	2,421

[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] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Conventional hydroelectric power excluding pumped storage facilities.
[5] Wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[6] The generation from a hydroelectric pumped storage facility is the net value of production minus the energy used for pumping.
[7] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[8] Includes a small number of generators for which waste heat is the primary energy source.
[9] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[10] 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.
[11] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[12] Anthracite, bituminous, subbituminous, lignite, and synthetic coal; excludes waste coal.
[13] 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.
[14] Beginning in 2002, includes data from the Form EIA-423 for independent power producers and combined heat and power producers.
[15] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately.
[16] 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.
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 independent rou

Sources: 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-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Form EIA-767, "Steam-Electric Plant Operation and Design Report;" Form EIA-860, "Annual Electric Generator Report;" Form EIA-861, "Annual Electric Power Industry Report;" Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms. Federal 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;" FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," and predecessor forms; Rural Utility Services (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, 1995 through 2006
(Million Megawatthours)

Category	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Supply												
Generation												
Electric Utilities	2,484	2,475[R]	2,505	2,462	2,549	2,630	3,015	3,174	3,212	3,123	3,077	2,995
Independent Power Producers	1,259	1,247[R]	1,119	1,063	955	781	458	201	91	59	60	58
Combined Heat and Power, Electric	165	180	184	196	194	170	165	155	154	148	147	141
Electric Power Sector Generation Subtotal	3,908	3,902[R]	3,808	3,721	3,698	3,580	3,638	3,530	3,457	3,329	3,284	3,194
Combined Heat and Power, Commercial	8	8	8	7	7	7	8	9	9	9	9	8
Combined Heat and Power, Industrial	148	145	154	155	153	149	157	156	154	154	151	151
Industrial and Commercial Generation Subtotal	157	153	162	162	160	157	165	165	163	163	160	159
Total Net Generation	4,065	4,055	3,971	3,883	3,858	3,737	3,802	3,695	3,620	3,492	3,444	3,353
Total Imports	43	45	34	30	37	39	49	43	40	43	43	43
Total Supply	**4,107**	**4,100[R]**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**	**3,488**	**3,396**
Disposition												
Retail Sales												
Full-Service Providers	3,438	3,413	3,318	3,285	3,324	3,297	3,310	3,236	3,240	3,140	3,098	3,013
Energy-Only Providers	219	237	222	189	141	98	112	76	24	6	3	NA[R]
Facility Direct Retail Sales	12	11	8	20	NA	NA	NA	NA	NA	NA	NA	NA
Total Electric Industry Retail Sales	3,670	3,661	3,547	3,494	3,465	3,394	3,421	3,312	3,264	3,146	3,101	3,013
Direct Use	147	150[R]	168	168	166	163	171	172	161	156	153	151
Total Exports	24	20	23	24	16[R]	16	15	14	14	9	3	4
Losses and Unaccounted For	266	269[R]	266	228	248[R]	202	244	240	221	224	231	229
Total Disposition	**4,107**	**4,100[R]**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**	**3,488**	**3,396**

NA = Not available.

R = Revised.

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-906, "Power Plant Report;" 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 FE-781R, "Annual Report of International Electrical Export/Import Data:" Canada data - National Energy Board of Canada (metered energy firm and interruptible).

Chapter 1. Generation and Useful Thermal Output

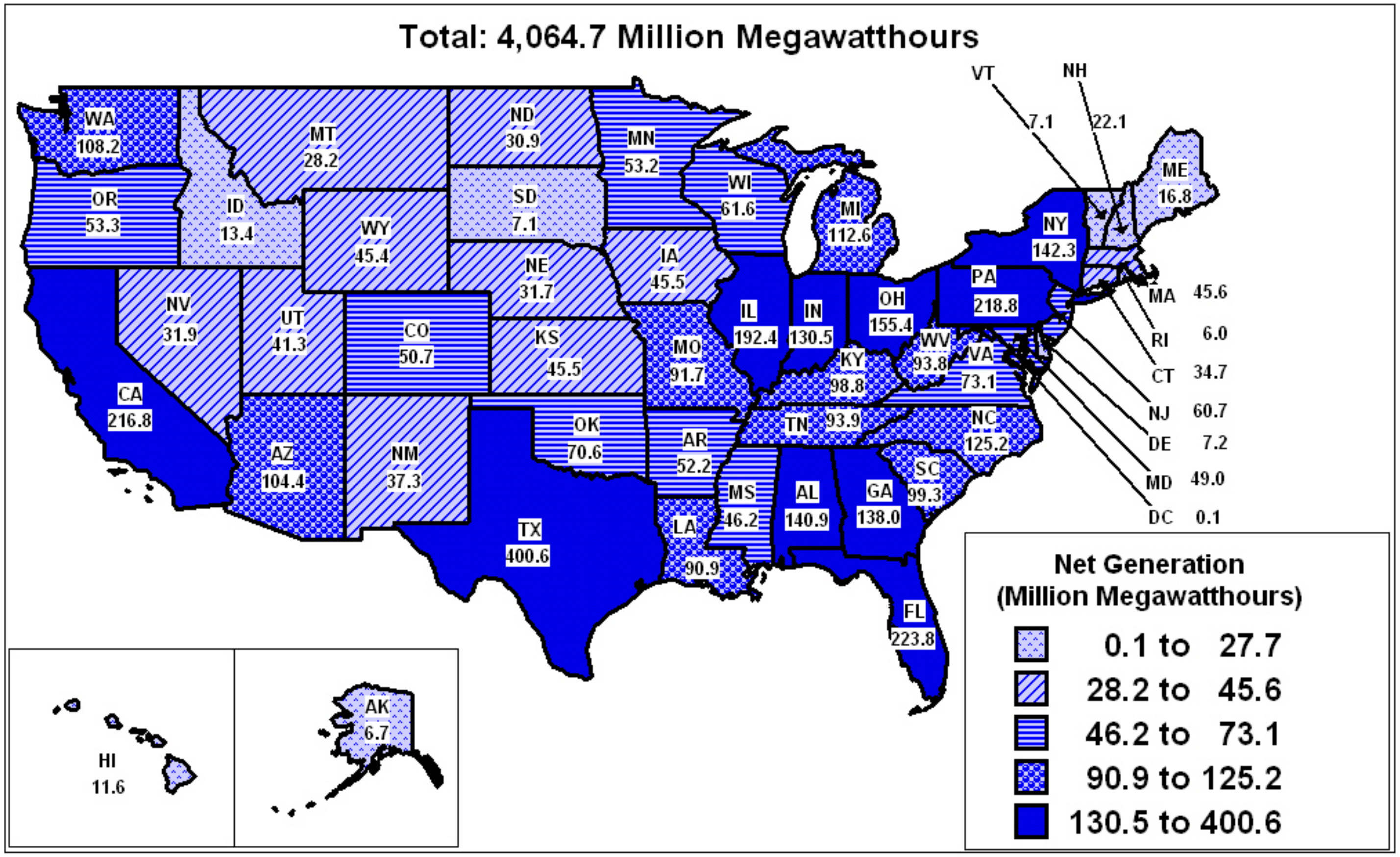
Table 1.1. Net Generation by Energy Source by Type of Producer, 1995 through 2006
(Thousand Megawatthours)

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)										
1995	1,709,426	74,554	496,058	13,870	673,402	310,833	73,965	-2,725	4,104	3,353,487
1996	1,795,196	81,411	455,056	14,356	674,729	347,162	75,796	-3,088	3,571	3,444,188
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[R]	-8,823	11,906[R]	3,736,644
2002	1,933,130	94,567	691,006	11,463	780,064	264,329	79,109[R]	-8,743	13,527[R]	3,858,452
2003	1,973,737	119,406	649,908	15,600	763,733	275,806	79,487[R]	-8,535	14,045[R]	3,883,185
2004	1,978,620	120,771[R]	708,854[R]	16,766	788,528	268,417	82,604[R]	-8,488	14,483[R]	3,970,555
2005	2,013,179	122,522	757,974	16,317	781,986	270,321[R]	87,213[R]	-6,558	12,468[R]	4,055,423[R]
2006	1,990,926	64,364	813,044	16,060	787,219	289,246	96,423	-6,558	13,977	4,064,702
Electricity Generators, Electric Utilities										
1995	1,652,914	60,844	307,306	--	673,402	296,378	6,409	-2,725	--	2,994,529
1996	1,737,453	67,346	262,730	--	674,729	331,058	7,214	-3,088	--	3,077,442
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[R]	-7,704	486[R]	2,629,946
2002	1,514,670	59,125	229,639	206	507,380	242,302	3,089[R]	-7,434	480[R]	2,549,457
2003	1,500,281	69,930	186,967	243	458,829	249,622	3,421[R]	-7,532	519[R]	2,462,281
2004	1,513,641	73,694	199,662	374	475,682	245,546	3,692[R]	-7,526	467[R]	2,505,231
2005	1,484,855[R]	69,722[R]	238,204[R]	10	436,296[R]	245,553[R]	4,945[R]	-5,383[R]	643[R]	2,474,846[R]
2006	1,471,421	40,903	282,088	30	425,341	261,864	6,588	-5,281	700	2,483,656
Electricity Generators, Independent Power Producers										
1995	5,044	1,162	10,136	6	--	9,033	32,841	--	--	58,222
1996	5,312	1,170	10,104	4	--	10,101	33,440	--	--	60,132
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[R]	-1,119	5,460[R]	780,592
2002	366,535	24,150	227,155	29	272,684	18,189	40,729[R]	-1,309	7,168[R]	955,331
2003	415,498	38,571	234,240	13	304,904	21,890	42,058[R]	-1,003	7,035[R]	1,063,205
2004	407,418	35,665	291,527	7	312,846	19,518	45,743[R]	-962	7,108[R]	1,118,870
2005	470,658[R]	41,485[R]	314,970[R]	3	345,690[R]	21,477[R]	48,294[R]	-1,174[R]	5,569[R]	1,246,971[R]
2006	462,302	14,340	335,898	3	361,877	24,383	55,890	-1,277	5,646	1,259,062
Combined Heat and Power, Electric Power										
1995	28,098	6,139	101,737	1,921	--	--	3,372	--	213	141,480
1996	29,207	6,267	105,923	1,337	--	--	3,632	--	201	146,567
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[R]	--	595[R]	169,515
2002	29,408	6,458	150,889	1,734	--	--	3,737[R]	--	1,444[R]	193,670
2003	36,935	5,195	146,097	2,392	--	--	4,002[R]	--	1,053[R]	195,674
2004	36,134	5,333[R]	136,206[R]	2,645	--	--	2,953[R]	--	988[R]	184,259
2005	36,547	5,560	130,142	3,948	--	10	3,420[R]	--	749[R]	180,375
2006	36,052	4,683	116,458	3,907	--	8	3,453	--	798	165,359
Combined Heat and Power, Commercial										
1995	998	379	5,162	--	--	118	1,575	--	*	8,232
1996	1,051	369	5,249	*	--	126	2,235	--	*	9,030
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[R]	--	457[R]	7,416
2002	992	431	4,310	*	--	13	1,065[R]	--	603[R]	7,415
2003	1,206	423	3,899	--	--	72	1,302[R]	--	594[R]	7,496
2004	1,323	469	4,051	--	--	105	1,541[R]	--	781[R]	8,270
2005	1,329	375	4,279	--	--	86	1,666[R]	--	756[R]	8,492
2006	1,289	242	4,345	24	--	93	1,595	--	783	8,371
Combined Heat and Power, Industrial										
1995	22,372	6,030	71,717	11,943	--	5,304	29,768	--	3,890	151,025
1996	22,172	6,260	71,049	13,015	--	5,878	29,274	--	3,370	151,017
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[R]	--	4,908[R]	149,175
2002	21,525	4,403	79,013	9,493	--	3,825	30,489[R]	--	3,832[R]	152,580
2003	19,817	5,285	78,705	12,953	--	4,222	28,704[R]	--	4,843[R]	154,530
2004	20,103	5,610	77,409	13,740	--	3,248	28,675[R]	--	5,139[R]	153,925
2005	19,791	5,380	70,380	12,356	--	3,195	28,887[R]	--	4,751[R]	144,739
2006	19,861	4,197	74,255	12,096	--	2,899	28,897	--	6,049	148,254

[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] Wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[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.
* = Value is less than half of the smallest unit of measure.

R = Revised.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Figure 1.1. U.S. Electric Industry Net Generation by State, 2006



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

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report" and Form EIA-920, "Combined Heat and Power Plant Report."

Table 1.2. Useful Thermal Output by Energy Source by Combined Heat and Power Producers, 1995 through 2006

(Billion Btus)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Other Renewables[4]	Other[5]	Total
Total Combined Heat and Power							
1995	386,403	120,790	686,182	144,715	768,338	44,389	2,150,817
1996	391,540	132,815	710,733	149,831	755,847	42,980	2,183,746
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[R]	55,162[R]	1,958,151
2002	336,848	72,826	708,738	117,513	571,507[R]	48,264[R]	1,855,697
2003	333,361	85,263	610,122	110,263	632,368[R]	54,960[R]	1,826,335
2004	346,083	96,439	504,548	133,821	683,657[R]	40,131[R]	1,804,678
2005	356,901	97,035	445,160	137,124	726,825[R]	41,089[R]	1,804,133
2006	338,747	77,775	456,063	128,038	731,785	47,577	1,779,986
Combined Heat and Power, Electric Power							
1995	40,427	13,044	117,994	4,344	26,910	249	202,968
1996	42,982	11,603	121,431	3,928	32,761	314	213,019
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[R]	3,343[R]	242,508
2002	40,020	3,869	214,137	5,961	12,550[R]	4,732[R]	281,269
2003	38,249	7,379	200,077	9,282	19,786[R]	3,296[R]	278,068
2004	22,153	1,250	129,791	16,043	8,284[R]	1,441[R]	178,962
2005	25,273	1,162	118,313	31,932	10,150[R]	2,508[R]	189,337
2006	28,234	574	105,472	17,396	9,854	3,111	164,642
Combined Heat and Power, Commercial							
1995	16,718	2,877	28,574	--	15,223	1	63,393
1996	19,742	2,905	32,770	--[R]	18,057	--	73,474
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	--[R]	17,145	--	77,779
2000	21,001	3,827	39,293	--[R]	17,613	--	81,734
2001	18,495	4,118	34,923	--	8,253[R]	5,770[R]	71,560
2002	18,477	2,743	36,265	--	6,901[R]	4,801[R]	69,188
2003	22,780	2,716	16,955	--	8,297[R]	6,142[R]	56,889
2004	23,753	4,023	21,418	--	10,413[R]	6,599[R]	66,205
2005	21,088	3,412	22,218	--	8,009[R]	5,461[R]	60,187
2006	20,504	2,269	27,508	1	8,422	5,563	64,267
Combined Heat and Power, Industrial							
1995	329,258	104,869	539,614	140,371	726,205	44,139	1,884,456
1996	328,816	118,307	556,532	145,903	705,029	42,666	1,897,253
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[R]	46,049[R]	1,644,083
2002	278,351	66,214	458,336	111,552	552,056[R]	38,731[R]	1,505,240
2003	272,332	75,168	393,090	100,981	604,285[R]	45,522[R]	1,491,378
2004	300,177	91,166	353,339	117,778	664,960[R]	32,091[R]	1,559,511
2005	310,540	92,461	304,629	105,192	708,666[R]	33,120[R]	1,554,609
2006	290,009	74,931	323,083	110,641	713,509	38,903	1,551,077

[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] Wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, and photovoltaic energy.

[5] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

R = Revised.

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

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Chapter 2. Capacity

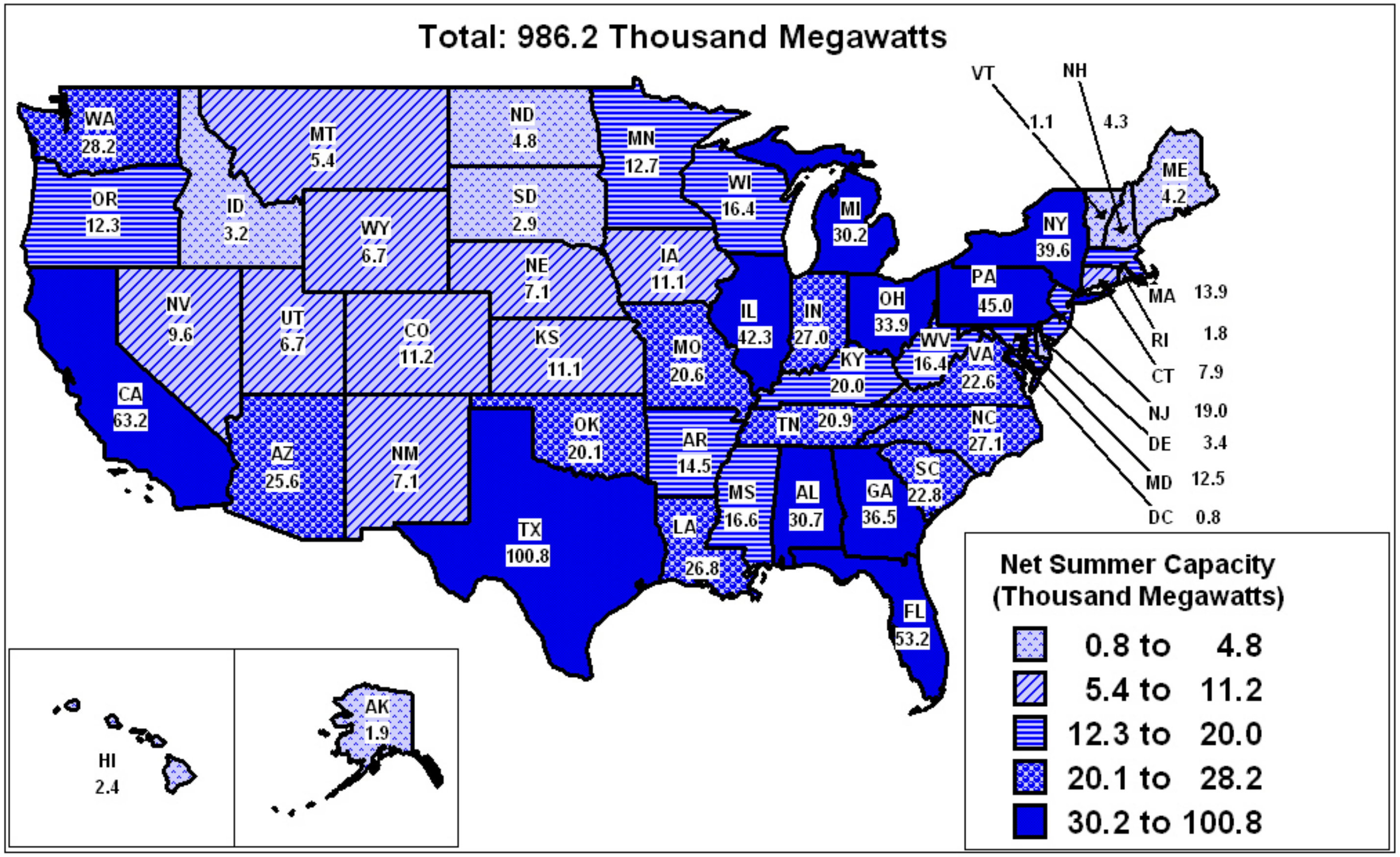
Table 2.1. Existing Net Summer Capacity by Energy Source and Producer Type, 1995 through 2006
(Megawatts)

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)										
1995	311,386	66,622[R]	174,482[R]	1,661	99,515	78,562	15,300	21,387	550	769,463
1996	313,382	72,518[R]	174,135[R]	1,664	100,784	76,437	15,309	21,110	550	775,890
1997	313,624	72,463[R]	176,471[R]	1,525	99,716	79,415	15,351	19,310	774	778,649
1998	315,786	66,282[R]	180,288[R]	1,520	97,070	79,151	15,444	19,518	810	775,868
1999	315,496	60,069[R]	195,119[R]	1,909	97,411	79,393	15,942	19,565	1,023	785,927
2000	315,114	61,837[R]	219,590[R]	2,342	97,860	79,359	15,572	19,522	523	811,719
2001	314,230	66,162[R]	252,832[R]	1,670	98,159	78,916	16,101[R]	19,664	519[R]	848,254
2002	315,350	59,651[R]	312,512[R]	2,008	98,657	79,356	16,710[R]	20,371	686[R]	905,301
2003	313,019	60,730[R]	355,442[R]	1,994	99,209	78,694	18,153[R]	20,522	684[R]	948,446
2004	313,020	59,119	371,011	2,296	99,628	77,641	18,717[R]	20,764	746[R]	962,942
2005	313,380	58,548	383,061	2,063	99,988	77,541	21,205[R]	21,347	887[R]	978,020
2006	312,956	58,097	388,294	2,256	100,334	77,821	24,113	21,461	882	986,215
Electricity Generators, Electric Utilities										
1995	300,569	64,451[R]	142,295[R]	291	99,515	75,274	2,330	21,387	--	706,111
1996	302,420	70,421[R]	139,936[R]	63	100,784	73,129	2,079	21,110	--	709,942
1997	302,866	69,557[R]	141,713[R]	206	99,716	76,177	2,123	19,310	222	711,889
1998	299,739	62,704[R]	130,404[R]	55	97,070	75,525	2,067	18,898	229	686,692
1999	277,780	49,020[R]	123,192[R]	220	95,030	74,122	790	18,945	224	639,324
2000	260,990	41,032[R]	123,665[R]	57	85,968	73,738	837	18,020	13	604,319
2001	244,451	38,456[R]	112,841[R]	57	63,060	72,968	979	17,097	13	549,920
2002	244,056	33,876	127,692	61	63,202	73,391	959[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[R]	30,867[R]	147,752[R]	--[R]	56,564[R]	71,568[R]	1,545[R]	18,195[R]	39	556,235[R]
2006	230,644	30,419	157,742	104	56,143	71,840	2,291	18,301	39	567,523
Electricity Generators, Independent Power Producers										
1995	719	221	2,987	--	--	2,151	6,887	--	--	12,964
1996	719	228	3,122	--	--	2,171	6,850	--	--	13,091
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	9,616[R]	2,567	79[R]	240,952
2002	61,770	23,664	140,404	9	35,455	4,911	10,420[R]	2,564	80[R]	279,246
2003	66,538	26,028	178,624	6	38,244	5,058	11,786[R]	2,719	46[R]	329,049
2004	67,242	25,918	190,855	8	38,978	5,274	12,070[R]	2,717	46[R]	343,106
2005	73,734[R]	26,041[R]	188,043[R]	12	43,424[R]	5,284[R]	13,864[R]	3,152[R]	46[R]	353,601[R]
2006	72,730	25,384	184,196	20	44,190	5,263	15,865	3,160	46	350,854
Combined Heat and Power, Electric Power										
1995	4,756	754	16,614	--	--	--	610	--	--	22,733
1996	4,950	699	18,350	--	--	--	626	--	--	24,625
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[R]	21,226[R]	287	--	1	776	--	28	27,917
2002	5,222	1,084[R]	28,455[R]	182	--	--	555	--	--	35,499
2003	5,534	1,051[R]	34,895[R]	185	--	1	665	--	--	42,332
2004	5,609	677	32,600	289	--	1	555	--	--	39,731
2005	5,560[R]	530[R]	31,740[R]	289[R]	--	1	614	--	--	38,735[R]
2006	5,837	970	30,031	325	--	1	628	--	--	37,793
Combined Heat and Power, Commercial										
1995	315	235	1,246	--	--	31	303	--	--	2,131
1996	321	267	1,243	--	--	31	446	--	--	2,309
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[R]	435	--	--	2,219[R]
2006	428	341	1,040	5	--	25	433	--	--	2,272
Combined Heat and Power, Industrial										
1995	5,028	961	11,339	1,370	--	1,106	5,171	--	550	25,524
1996	4,972	903	11,482	1,602	--	1,106	5,308	--	550	25,923
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[R]	14,501	1,757	--	662	4,747[R]	--	802	27,230[R]
2006	3,317	983	15,285	1,802	--	693	4,896	--	797	27,773

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

Figure 2.1. U.S. Electric Industry Generating Capacity by State, 2006



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

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

Table 2.2. Existing Capacity by Energy Source, 2006
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[1]	1,493	335,830	312,956	315,163
Petroleum[2]	3,744	64,318	58,097	62,565
Natural Gas[3]	5,470	442,945	388,294	416,745
Other Gases[4]	105	2,563	2,256	2,197
Nuclear	104	105,585	100,334	101,718
Hydroelectric Conventional[5]	3,988	77,419	77,821	77,393
Other Renewables[6]	1,823	26,470	24,113	24,285
Pumped Storage	150	19,569	21,461	21,374
Other[7]	47	976	882	908
Total	**16,924**	**1,075,677**	**986,215**	**1,022,347**

[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] 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, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[7] 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.

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

Table 2.3. Existing Capacity by Producer Type, 2006
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector				
Electric Utilities	9,249	610,057	567,523	584,310
Independent Power Producers	4,585	388,066	350,854	366,023
Total	**13,834**	**998,122**	**918,377**	**950,333**
Combined Heat and Power Sector				
Electric Power[1]	661	43,427	37,793	40,524
Commercial	640	2,584	2,272	2,366
Industrial	1,789	31,543	27,773	29,125
Total	**3,090**	**77,554**	**67,838**	**72,015**
Total All Sectors	**16,924**	**1,075,677**	**986,215**	**1,022,347**

[1] Includes only independent power producers` combined heat and power facilities.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.

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

Table 2.4. Planned Nameplate Capacity Additions from New Generators, by Energy Source, 2007 through 2011
(Megawatts)

Energy Source	2007	2008	2009	2010	2011
Coal[1]	1,679	920	12,611	6,839	7,649
Petroleum[2]	255	1	835	50	--
Natural Gas	9,891	12,896	11,050	7,569	4,622
Other Gases[3]	--	580	771	--	340
Nuclear	--	--	--	--	--
Hydroelectric Conventional	13	3	1	--	--
Other Renewables[4]	5,714	2,032	350	217	56
Pumped Storage	--	--	--	--	--
Other[5]	--	--	--	--	165
Total	**17,552**	**16,432**	**25,617**	**14,675**	**12,833**

[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] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[5] 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 January 1, 2007. • Totals may not equal sum of components because of independent rounding.

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

Table 2.5. Planned Capacity Additions from New Generators, by Energy Source, 2007-2011
(Count, Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
2007				
U.S. Total	**263**	**17,552**	**16,000**	**16,985**
Coal[1]	4	1,679	1,572	1,578
Petroleum[2]	38	255	235	245
Natural Gas	85	9,891	8,517	9,482
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional	3	13	12	12
Other Renewables[4]	133	5,714	5,664	5,669
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--
2008				
U.S. Total	**156**	**16,432**	**14,491**	**15,770**
Coal[1]	3	920	861	865
Petroleum[2]	1	1	1	1
Natural Gas	115	12,896	11,121	12,343
Other Gases[3]	2	580	500	550
Nuclear	--	--	--	--
Hydroelectric Conventional	1	3	3	3
Other Renewables[4]	34	2,032	2,005	2,008
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--
2009				
U.S. Total	**102**	**25,617**	**23,014**	**24,216**
Coal[1]	19	12,611	11,755	11,854
Petroleum[2]	3	835	766	789
Natural Gas	71	11,050	9,495	10,502
Other Gases[3]	3	771	663	727
Nuclear	--	--	--	--
Hydroelectric Conventional	1	1	1	1
Other Renewables[4]	5	350	334	343
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--
2010				
U.S. Total	**63**	**14,675**	**13,030**	**13,701**
Coal[1]	16	6,839	6,248	6,304
Petroleum[2]	2	50	49	50
Natural Gas	40	7,569	6,524	7,138
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional	--	--	--	--
Other Renewables[4]	5	217	209	210
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--
2011				
U.S. Total	**35**	**12,833**	**11,484**	**12,080**
Coal[1]	15	7,649	7,026	7,190
Petroleum[2]	--	--	--	--
Natural Gas	16	4,622	3,971	4,362
Other Gases[3]	1	340	292	320
Nuclear	--	--	--	--
Hydroelectric Conventional	--	--	--	--
Other Renewables[4]	2	56	52	52
Pumped Storage	--	--	--	--
Other[5]	1	165	142	155

[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] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[5] 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 January 1, 2007. • Totals may not equal sum of components because of independent rounding.

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

Table 2.6. Capacity Additions, Retirements and Changes by Energy Source, 2006
(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 (MW)
Coal[2]	5	603	542	543	20	751	735	747	87	-232	-189
Petroleum[3]	54	184	177	177	78	243	214	225	-467	-414	-557
Natural Gas[4]	86	9,491	8,563	9,011	68	2,710	2,418	2,522	-828	-912	-1,985
Other Gases[5]	--	--	--	--	1	4	4	4	274	197	188
Nuclear	--	--	--	--	--	--	--	--	--	346	194
Hydroelectric	1	2	1	1	6	3	1	1	67	395	384
Other Renewables[6]	129	2,872	2,847	2,855	12	54	49	51	157	111	50
Other[7]	--	--	--	--	1	38	37	37	29	33	36
Total	**275**	**13,152**	**12,129**	**12,587**	**186**	**3,804**	**3,458**	**3,588**	**-681**	**-476**	**-1,879**

[1] Generator re-ratings, re-powering, and revisions/corrections to previously reported data.
[2] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic 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, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[7] 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.

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

Table 2.7.A. Capacity of Dispersed Generators by Technology Type, 2005 and 2006
(Count, Megawatts)

Period	Internal Combustion	Combustion Turbine	Steam Turbine	Hydroelectric	Wind and Other	Total	
	Capacity	Capacity	Capacity	Capacity	Capacity	Number of Generators	Capacity
2004	3,369	210	552	26	2	11,123	4,156
2005	4,292	334	126	2	13	11,373	4,766
2006	6,469	339	156	2	8	9,536	7,037

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 Technology includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 2.7.B. Capacity of Distributed Generators by Technology Type, 2005 and 2006
(Count, Megawatts)

Period	Internal Combustion	Combustion Turbine	Steam Turbine	Hydroelectric	Wind and Other	Total	
	Capacity	Capacity	Capacity	Capacity	Capacity	Number of Generators	Capacity
2004	2,169	1,028	1,086	1,003	137	5,863	5,423
2005[1]	4,024	1,917	1,831	998	994	17,371	9,766
2006	3,625	1,299	2,580	806	1,078	5,044	9,641

[1] Distributed generator data in 2005 include a significant number of generators reported by one respondent which may be for residential applications.
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 Technology includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 2.7.C. Total Capacity of Dispersed and Distributed Generators by Technology Type, 2005 and 2006
(Count, Megawatts)

Period	Internal Combustion	Combustion Turbine	Steam Turbine	Hydroelectric	Wind and Other	Total	
	Capacity	Capacity	Capacity	Capacity	Capacity	Number of Generators	Capacity
2004	5,538	1,238	1,638	1,029	139	16,986	9,579
2005[1]	8,316	2,251	1,957	1,000	1,007	28,744	14,532
2006	10,094	1,638	2,736	808	1,086	14,580	16,678

[1] Distributed generator data in 2005 include a significant number of generators reported by one respondent which may be for residential applications.
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 Technology includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 2.8. Fuel Switching Capacity of Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2006
(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[1]	Fuel-Switchable Net Summer Capacity Reporting No Regulatory Limits on Use of Petroleum Liquids[1]
Electric Utility	157,742	72,802	46.2	70,153	22,956
Independent Power Producers	184,196	41,408	22.5	40,733	8,102
Combined Heat and Power, Electric Power[2]	30,031	6,408	21.3	6,420	697
Electric Power Sector Subtotal	**371,969**	**120,618**	**32.4**	**117,307**	**31,755**
Combined Heat and Power, Commercial	1,040	472	45.4	482	52
Combined Heat and Power, Industrial	15,285	1,033	6.8	957	225
All Sectors	**388,294**	**122,124**	**31.5**	**118,746**	**32,031**

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

Table 2.9. Fuel Switching Capacity of Generators Reporting Petroleum Liquids as the Primary Fuel, by Producer Type, 2006
(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	30,419	10,269	33.8	9,714
Independent Power Producers	25,384	11,669	46.0	9,842
Combined Heat and Power Electric Power[2]	970	445	45.9	195
Electric Power Sector Subtotal	**56,773**	**22,383**	**39.4**	**19,751**
Combined Heat and Power Commercial	341	29	8.4	28
Combined Heat and Power Industrial	983	161	16.4	125
All Sectors	**58,097**	**22,573**	**38.9**	**19,904**

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

Table 2.10. Fuel-Switching Capacity: From Natural Gas to Petroleum Liquids, by Type of Prime Mover, 2006
(Count, Megawatts)

Prime Mover Type	Number of Generators	Net Summer Capacity	Net Summer Capacity Reported as Having No Regulatory Limits on use of Petroleum Liquids[1]
Steam Generator	235	33,470	16,237
Combined Cycle	396	36,139	3,980
Internal Combustion	324	878	245
Gas Turbine	914	51,636	11,570
All Fuel Switchable Prime Movers	1,869	122,124	32,031

[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 2.11. Fuel-Switching Capacity: From Natural Gas to Petroleum Liquids, by Year of Initial Commercial Operation, 2006
(Count, Megawatts)

Year of Commercial Operation	Number of Generators	Net Summer Capacity	Net Summer Capacity Reported as Having No Regulatory Limits on use of Petroleum Liquids[1]
pre-1970	414	18,227	9,355
1970-1974	387	19,385	7,414
1975-1979	115	10,422	4,606
1980-1984	46	2,795	2,038
1985-1989	122	3,312	282
1990-1994	217	12,781	1,654
1995-1999	140	9,835	2,260
2000-2004	381	39,144	3,408
2005-2006	47	6,223	1,014
Total	1,869	122,124	32,031

[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 2.12. Interconnection Cost and Capacity for New Generators, by Producer Type, 2005 and 2006

Sector	Units	Nameplate Capacity (megawatts)	Cost (thousand dollars)[1]
2005			
Total	242	19,666	288,826
Electric Utilities[2]	159	12,708	189,358
Independent Power Producers[3]	60	6,106	93,517
Commercial[4]	9	34	13
Industrial[5]	14	818	5,938
2006			
Total	275	13,152	251,953
Electric Utilities[2]	113	6,706	94,574
Independent Power Producers[3]	137	6,265	149,086
Commercial[4]	18	67	1,836
Industrial[5]	7	114	6,457

[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.
[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 commercial electricity-only plants included.
[5] Small number of industrial electricity-only plants included.
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.13. Interconnection Cost and Capacity for New Generators, by Grid Voltage Class, 2005 and 2006

Voltage Class	Units	Nameplate Capacity (megawatts)	Cost (thousand dollars)[1]
2005			
Total	242	19,666	288,826
Distribution (< 35 kV)	76	236	18,552
SubTransmission (35 kV - 138 kV)	79	6,794	122,479
Transmission (> 138 kV)	87	12,635	147,795
2006			
Total	275	13,152	251,953
Distribution (< 35 kV)	144	424	18,752
SubTransmission (35 kV - 138 kV)	56	4,102	76,905
Transmission (> 138 kV)	75	8,626	156,296

[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.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.

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

Chapter 3. Demand, Capacity Resources, and Capacity Margins

Table 3.1. Noncoincident Peak Load, Actual and Projected by North American Electric Reliability Council Region, 2002 through 2011
(Megawatts)

North American Electric Reliability Council Region	Actual				
	2002	2003	2004	2005	2006
Summer					
ECAR[1]	102,996	98,487	95,300	NA	NA
ERCOT	56,248	59,996	58,531	60,210	62,339
FRCC	40,696	40,475	42,383	46,396	45,751
MAAC[1]	55,569	53,566	52,049	NA	NA
MAIN[1]	56,396	56,988	53,439	NA	NA
MRO (U.S.) [2]	29,119	28,831	29,351	39,918	42,194
NPCC (U.S.)	56,012	55,018	52,549	58,960	63,241
Reliability*First*[3]	NA	NA	NA	190,200	191,920
SERC	158,767	153,110	157,615	190,705	199,052
SPP	39,688	40,367	40,106	41,727	42,882
WECC (U.S.)	119,074	122,537	123,136	130,760	142,096
Contiguous U.S.	**714,565**	**709,375**	**704,459**	**758,876**	**789,475**
Winter					
ECAR[1]	87,300	86,332	91,800	NA	NA
ERCOT	45,414	42,702	44,010	48,141	50,402
FRCC	45,635	36,841	44,839	42,657	42,526
MAAC[1]	46,551	45,625	45,905	NA	NA
MAIN[1]	42,412	41,719	42,929	NA	NA
MRO (U.S.) [2]	23,645	24,134	24,526	33,748	34,677
NPCC (U.S.)	46,009	48,079	48,176	46,828	46,697
Reliability*First*[3]	NA	NA	NA	151,600	149,631
SERC	141,882	137,972	144,337	164,638	175,163
SPP	30,187	28,450	29,490	31,260	30,792
WECC (U.S.)	95,951	102,020	102,689	107,493	111,093
Contiguous U.S.	**604,986**	**593,874**	**618,701**	**626,365**	**640,981**

North American Electric Reliability Council Region	Projected				
	2007	2008	2009	2010	2011
Summer					
ERCOT	63,794	65,135	66,508	67,955	69,456
FRCC	46,878	48,037	49,280	50,249	51,407
MRO (U.S.) [2]	43,431	44,478	45,976	46,986	47,727
NPCC (U.S.)	60,807	61,756	62,795	63,769	64,776
Reliability*First*[3]	188,856	191,929	195,020	197,798	200,760
SERC	201,692	205,651	210,036	214,590	218,305
SPP	43,007	43,939	44,827	45,675	46,487
WECC (U.S.)	137,465	140,284	143,175	146,044	148,854
Contiguous U.S.	**785,930**	**801,209**	**817,617**	**833,066**	**847,772**
Winter					
ERCOT	47,163	48,243	49,362	50,326	51,047
FRCC	49,526	50,737	51,673	52,780	53,872
MRO (U.S.) [2]	35,495	36,655	37,642	38,389	38,929
NPCC (U.S.)	48,394	49,123	49,683	50,306	50,921
Reliability*First*[3]	151,597	153,388	155,281	157,336	159,159
SERC	178,337	181,746	185,414	187,778	191,008
SPP	30,801	31,428	32,099	32,713	33,281
WECC (U.S.)	110,073	111,785	114,066	115,928	117,534
Contiguous U.S.	**651,386**	**663,105**	**675,220**	**685,556**	**695,751**

[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 Regional Council names may be found in the Glossary reference. • 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: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Table 3.2. Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Summer, 1995 through 2006

(Megawatts)

Region and Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
ECAR[1]												
Net Internal Demand[2]	NA	NA	95,300	98,487	101,251	100,235	98,651	94,072	92,359	91,103	88,573	85,643
Capacity Resources[3]...................	NA	NA	127,919	123,755	119,736	113,136	115,379	107,451	105,545	105,106	104,953	103,003
Capacity Margin (percent)[4].........	NA	NA	25.5	20.4	15.4	11.4	14.5	12.5	12.5	13.3	15.6	16.9
ERCOT												
Net Internal Demand[2]	62,669	59,060	58,531	59,282	55,833	55,106	53,649	51,697	50,254	47,746	45,636	44,990
Capacity Resources[3]...................	71,156	66,724	73,850	74,764	76,849	70,797	69,622	65,423	59,788	55,771	55,230	55,074
Capacity Margin (percent)[4].........	11.9	11.5	20.7	20.7	27.3	22.2	22.9	21.0	15.9	14.4	17.4	18.3
FRCC												
Net Internal Demand[2]	43,824	45,950	42,243	40,387	37,951	38,932	35,666	34,832	34,562	32,874	31,868	31,649
Capacity Resources[3]...................	53,171	50,200	48,579	46,806	43,342	42,290	43,083	40,645	39,708	39,613	38,237	38,282
Capacity Margin (percent)..........	17.6	8.5	13.0	13.7	12.4	7.9	17.2	14.3	13.0	17.0	16.7	17.3
MAAC[1]												
Net Internal Demand[2]	NA	NA	52,049	53,566	54,296	54,015	51,358	49,325	47,626	46,548	45,628	45,224
Capacity Resources[3]...................	NA	NA	66,167	65,897	63,619	59,533	60,679	57,831	55,511	56,155	56,774	56,881
Capacity Margin (percent)[4].........	NA	NA	21.3	18.7	14.7	9.3	15.4	14.7	14.2	17.1	19.6	20.5
MAIN[1]												
Net Internal Demand[2]	NA	NA	50,499	53,617	53,267	53,032	51,845	47,165	45,570	45,194	44,470	43,229
Capacity Resources[3]...................	NA	NA	65,677	67,410	67,025	65,950	64,170	55,984	52,722	52,160	52,880	52,112
Capacity Margin (percent)[4].........	NA	NA	23.1	20.5	20.5	19.6	19.2	15.8	13.6	13.4	15.9	17.0
MRO (U.S.)[5]												
Net Internal Demand[2]	41,754	38,266	29,094	28,775	28,825	27,125	28,006	30,606	29,766	28,221	27,298	27,487
Capacity Resources[3]...................	49,792	46,792	35,830	33,287	34,259	32,271	34,236	35,373	34,773	34,027	33,121	32,665
Capacity Margin (percent)[4].........	16.1	18.2	18.8	13.6	15.9	15.9	18.2	13.5	14.4	17.1	17.6	15.9
NPCC (U.S.)												
Net Internal Demand[2]	59,727	57,402	51,580	53,936	55,164	55,888	54,270	53,450	51,760	50,240	48,950	48,290
Capacity Resources[3]...................	70,607	72,258	71,532	70,902	66,208	63,760	63,376	63,077	60,439	60,729	58,592	62,368
Capacity Margin (percent)[4].........	15.4	20.6	27.9	23.9	16.7	12.3	14.4	15.3	14.4	17.3	16.5	22.6
Reliability*First*[6]												
Net Internal Demand[2]	179,600	190,200	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Resources[3]...................	213,792	220,000	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Margin (percent)[4].........	16.0	13.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
SERC												
Net Internal Demand[2]	196,111	186,049	153,024	148,380	154,459	144,399	151,527	142,726	138,146	134,968	109,270	105,785
Capacity Resources[3]...................	231,123	219,749	182,861	177,231	172,485	171,530	169,760	160,575	158,360	155,016	126,196	127,562
Capacity Margin (percent)[4].........	15.1	15.3	16.3	16.3	10.5	15.8	10.7	11.1	12.8	12.9	13.4	17.1
SPP												
Net Internal Demand[2]	42,266	41,079	39,383	39,428	38,298	38,807	39,056	37,807	36,402	37,009	59,017	57,951
Capacity Resources[3]...................	46,564	46,376	48,000	45,802	47,233	45,530	46,109	43,111	42,554	43,591	69,344	69,354
Capacity Margin (percent)[4].........	9.2	11.4	18.0	13.9	18.9	14.8	15.3	12.3	14.5	15.1	14.9	16.4
WECC (U.S.)												
Net Internal Demand[2]	134,157	128,464	121,205	120,894	117,032	107,294	116,913	112,177	111,641	104,486	101,728	99,612
Capacity Resources[3]...................	169,950	160,026	155,455	150,277	142,624	124,193	141,640	136,274	135,270	135,687	135,049	130,180
Capacity Margin (percent)[4].........	21.1	19.7	22.0	19.6	17.9	13.6	17.5	17.7	17.5	23.0	24.7	23.5
Contiguous U.S.												
Net Internal Demand[2]..............	**760,108**	**746,470**	**692,908**	**696,752**	**696,376**	**674,833**	**680,941**	**653,857**	**638,086**	**618,389**	**602,438**	**589,860**
Capacity Resources[3].................	**906,155**	**882,125**	**875,870**	**856,131**	**833,380**	**788,990**	**808,054**	**765,744**	**744,670**	**737,855**	**730,376**	**727,481**
Capacity Margin (percent)[4]	**16.1**	**15.4**	**20.9**	**18.6**	**16.4**	**14.5**	**15.7**	**14.6**	**14.3**	**16.2**	**17.5**	**18.9**

[1] ECAR, MAAC, and MAIN dissolved at the end of 2005. Utility membership joined other reliability regional councils. Also, see Footnote 6.
[2] 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.
[3] 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.
[4] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
[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.

NA = Not available.

Notes: • NERC Regional Council names may be found in the Glossary reference. • 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: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Table 3.3. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Summer, 2006 through 2011
(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]
		2006			2007	
ERCOT	62,669	71,156	11.9	64,010	71,510	10.5
FRCC	43,824	53,171	17.6	44,880	54,927	18.3
MRO (U.S.)[4]	41,754	49,792	16.1	42,787	49,722	13.9
NPCC (U.S.)	59,727	70,607	15.4	60,676	70,341	13.7
Reliability*First*[5]	179,600	213,792	16.0	182,500	215,296	15.2
SERC	196,111	231,123	15.1	200,073	230,489	13.2
SPP	42,266	46,564	9.2	43,196	47,758	9.6
WECC (U.S.)	134,157	169,950	21.1	136,804	173,695	21.2
Contiguous U.S.	**760,108**	**906,155**	**16.1**	**774,926**	**913,738**	**15.2**
		2008			2009	
ERCOT	65,383	71,405	8.4	66,830	71,839	7.0
FRCC	46,033	58,408	21.2	46,930	61,084	23.2
MRO (U.S.)[4]	44,288	49,841	11.1	45,383	50,028	9.3
NPCC (U.S.)	61,715	70,671	12.7	62,689	70,320	10.9
Reliability*First*[5]	186,200	216,512	14.0	189,000	217,119	13.0
SERC	204,432	235,229	13.1	208,908	242,315	13.8
SPP	44,073	48,097	8.4	44,911	50,309	10.7
WECC (U.S.)	139,704	175,753	20.5	142,514	179,070	20.4
Contiguous U.S.	**791,828**	**925,916**	**14.5**	**807,165**	**942,084**	**14.3**
		2010			2011	
ERCOT	68,331	72,553	5.8	69,608	73,317	5.1
FRCC	48,016	63,492	24.4	49,006	67,215	27.1
MRO (U.S.)[4]	46,118	50,445	8.6	47,036	50,868	7.5
NPCC (U.S.)	63,696	70,320	9.4	64,661	70,320	8.0
Reliability*First*[5]	191,900	217,734	11.9	194,200	217,815	10.8
SERC	212,603	246,919	13.9	216,726	251,507	13.8
SPP	45,711	51,544	11.3	46,463	52,491	11.5
WECC (U.S.)	145,237	180,214	19.4	147,896	180,126	17.9
Contiguous U.S.	**821,612**	**953,221**	**13.8**	**835,596**	**963,659**	**13.3**

[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] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[5] 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: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Table 3.4. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Winter, 2006 through 2011
(Megawatts)

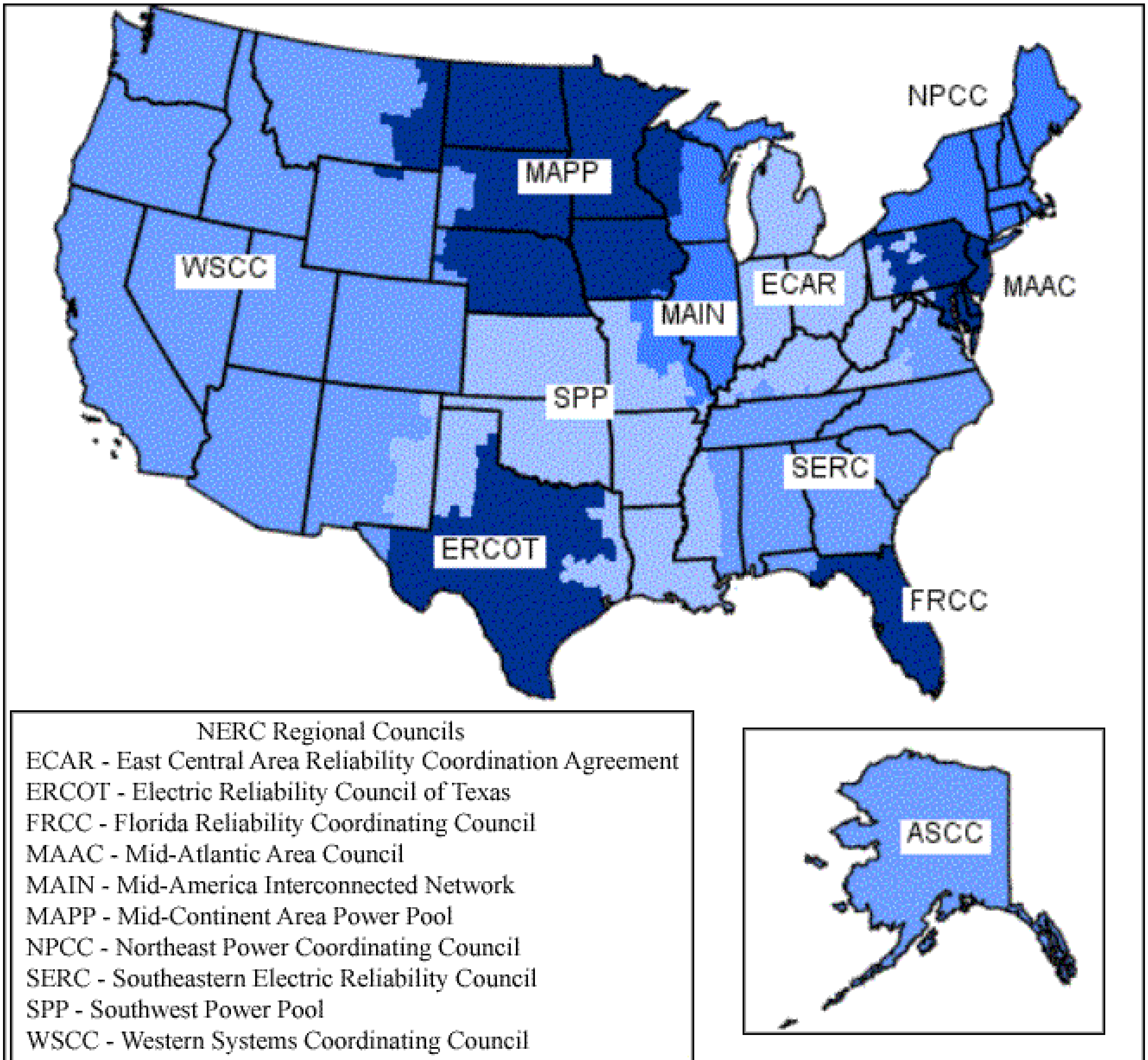
North American Electric Reliability Council Region	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[2]
		2006/ 2007			2007/ 2008	
ERCOT	46,038	71,451	35.6	47,118	74,286	36.6
FRCC	45,993	56,896	19.2	47,112	59,246	20.5
MRO (U.S.)[4]	34,582	46,959	26.4	35,736	47,999	25.5
NPCC (U.S.)	48,394	76,110	36.4	49,123	75,947	35.3
Reliability*First*[5]	147,800	220,930	33.1	149,700	222,542	32.7
SERC	173,036	231,917	25.4	176,412	232,732	24.2
SPP	30,469	47,199	35.4	31,096	47,855	35.0
WECC (U.S.)	107,586	166,362	35.3	109,489	170,097	35.6
Contiguous U.S.	**633,898**	**917,824**	**30.9**	**645,786**	**930,704**	**30.6**
		2008/ 2009			2009/ 2010	
ERCOT	48,237	74,221	35.0	49,201	75,572	34.9
FRCC	47,991	62,703	23.5	49,029	65,760	25.4
MRO (U.S.)[4]	36,726	48,325	24.0	37,569	48,785	23.0
NPCC (U.S.)	49,683	75,382	34.1	50,306	75,922	33.7
Reliability*First*[5]	151,600	223,172	32.1	153,700	224,379	31.5
SERC	180,072	233,256	22.8	182,480	237,419	23.1
SPP	31,769	48,953	35.1	32,391	50,590	36.0
WECC (U.S.)	111,742	172,096	35.1	113,694	174,846	35.0
Contiguous U.S.	**657,820**	**938,108**	**29.9**	**668,370**	**953,273**	**29.9**
		2010/ 2011			2011/ 2012	
ERCOT	49,922	76,372	34.6	51,257	76,392	32.9
FRCC	50,064	68,151	26.5	51,117	71,112	28.1
MRO (U.S.)[4]	38,108	49,162	22.5	38,780	49,624	21.9
NPCC (U.S.)	50,921	75,922	32.9	51,710	75,922	31.9
Reliability*First*[5]	156,000	224,334	30.5	157,700	224,359	29.7
SERC	185,661	242,897	23.6	188,346	246,507	23.6
SPP	32,958	51,438	35.9	33,506	52,439	36.1
WECC (U.S.)	115,225	176,124	34.6	116,888	176,389	33.7
Contiguous U.S.	**678,859**	**964,400**	**29.6**	**689,304**	**972,744**	**29.1**

[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] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[5] 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.

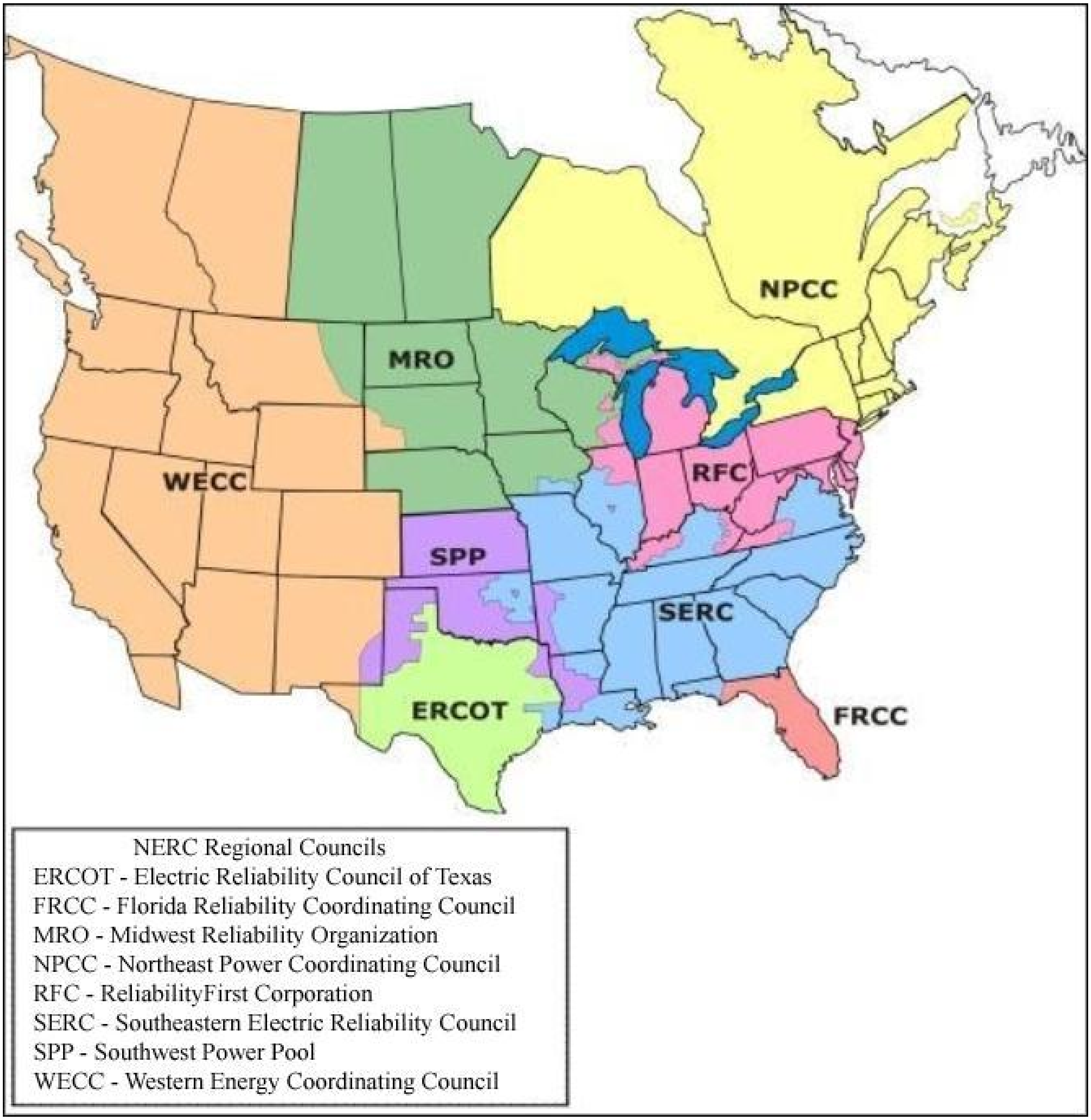
Source: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Figure 3.1 Historical North American Reliability Council Regions for the Contiguous U.S., 1996



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

Figure 3.2 Consolidated North American Electric Reliability Council Regions, 2006



Source: North American Electric Reliability Corporation.

Chapter 4. Fuel

Table 4.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1995 through 2006

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)				
1995	860,594	132,578	4,737,871	132,520
1996	907,209	144,626	4,312,458	158,560
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	1,026,018	209,508	6,116,574	186,796
2005	1,045,878	211,256	6,486,761	176,906
2006	1,035,346	115,370	6,869,624	181,081
Electricity Generators, Electric Utilities				
1995	829,007	105,956	3,196,507	--
1996	874,681	116,680	2,732,107	--
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	761,349R	118,874R	2,134,859R	91
2006	753,390	71,624	2,478,396	358
Electricity Generators, Independent Power Producers				
1995	3,921	2,342	91,064	87
1996	4,143	2,169	91,617	71
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	254,291R	72,953R	2,457,412R	43
2006	251,379	26,873	2,612,653	49
Combined Heat and Power, Electric Power				
1995	14,926	11,366	806,202	18,080
1996	15,575	11,320	836,086	15,494
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	20,306	10,620	1,164,328	33,202
2005	20,500	10,099	1,132,641	43,941
2006	20,337	8,740	1,005,932	42,391
Combined Heat and Power, Commercial				
1995	569	649	42,700	--
1996	656	645	42,380	*
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	602	1,188	45,883	--
2005	770	939	47,851	--
2006	743	481	48,384	--
Combined Heat and Power, Industrial				
1995	12,171	12,265	601,397	114,353
1996	12,153	13,813	610,268	142,995
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	10,337	10,100	764,828	148,345
2005	8,969	8,392	713,999	132,831
2006	9,496	7,651	724,259	138,283

[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.
* = Value is less than half of the smallest unit of measure.
R = Revised.
Note: See Glossary reference for definitions
Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Table 4.2. Consumption of Fossil Fuels for Useful Thermal Output by Type of Combined Heat and Power Producers, 1995 through 2006

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				
1995	20,418	25,562	834,382	180,895
1996	20,806	27,873	865,774	187,290
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	18,779	19,856	610,105	167,273
2005	19,402	19,937	541,206	171,406
2006	18,437	15,636	549,335	160,048
Electric Power[4]				
1995	2,376	2,784	142,753	5,430
1996	2,520	2,424	147,091	4,912
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	1,189	277	157,900	20,054
2005	1,345	258	144,233	39,918
2006	1,529	127	125,119	21,745
Commercial				
1995	850	596	34,964	--
1996	1,005	601	40,075	--
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	1,315	821	26,189	--
2005	1,151	691	27,364	--
2006	1,143	453	33,877	1
Industrial				
1995	17,192	22,182	656,665	175,465
1996	17,281	24,848	678,608	182,378
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	16,276	18,758	426,016	147,219
2005	16,906	18,987	369,609	131,488
2006	15,765	15,055	390,338	138,302

[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.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Table 4.3. Consumption of Fossil Fuels for Electricity Generation and for Useful Thermal Output, 1995 through 2006

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1995	881,012	158,140	5,572,253	313,415
1996	928,015	172,499	5,178,232	345,850
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	354,069
2005	1,065,281	231,193	7,027,967	348,312
2006	1,053,783	131,005	7,418,959	341,129
Electricity Generators, Electric Utilities				
1995	829,007	105,956	3,196,507	--
1996	874,681	116,680	2,732,107	--
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	761,349R	118,874R	2,134,859R	91
2006	753,390	71,624	2,478,396	358
Electricity Generators, Independent Power Producers				
1995	3,921	2,342	91,064	87
1996	4,143	2,169	91,617	71
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	254,291R	72,953R	2,457,412R	43
2006	251,379	26,873	2,612,653	49
Combined Heat and Power, Electric Power				
1995	17,302	14,149	948,954	23,510
1996	18,096	13,744	983,177	20,406
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	53,256
2005	21,845	10,357	1,276,874	83,858R
2006	21,867	8,867	1,131,051	64,136
Combined Heat and Power, Commercial				
1995	1,419	1,245	77,664	--
1996	1,660	1,246	82,455	*
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	75,215	--
2006	1,886	935	82,261	1
Combined Heat and Power, Industrial				
1995	29,363	34,448	1,258,063	289,818
1996	29,434	38,661	1,288,876	325,373
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	295,564
2005	25,875	27,380	1,083,607	264,319
2006	25,262	22,706	1,114,597	276,585

[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.
* = Value is less than half of the smallest unit of measure.
R = Revised.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Table 4.4. End-of-Year Stocks of Coal and Petroleum by Type of Producer, 1995 through 2006

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)[1]	Petroleum (Thousand Barrels)[2]
1995	126,304	50,821	126,304	50,821	NA	NA
1996	114,623	48,146	114,623	48,146	NA	NA
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	77,457R	31,400R	23,680R	18,661R
2006	140,964	51,583	110,277	32,082	30,688	19,502

[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.
R = Revised.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Table 4.5. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1995 through 2006

Period	Coal[1]				Petroleum[2]				Natural Gas[3]		All Fossil Fuels
	Receipts	Average Cost		Avg. Sulfur Percent by Weight	Receipts	Average Cost		Avg. Sulfur Percent by Weight	Receipts	Average Cost	Average Cost
	(thousand tons)	(cents/ 10^6 Btu)	(dollars/ ton)		(thousand barrels)	(cents/ 10^6 Btu)	(dollars/ barrel)		(thousand Mcf)	(cents/ 10^6 Btu)	(cents/ 10^6 Btu)
1995	826,860	132	27.01	1.08	89,908	257	16.10	1.21	3,023,327	198	145
1996	862,701	129	26.45	1.10	113,678	303	18.98	1.26	2,604,663	264	152
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[4]	884,287	125	25.52	.94	120,851	334	20.77	1.64	5,607,737	356	152
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[R]	821	325[R]
2006	1,079,943	169	34.09	.97	100,965	623	37.66	2.31	6,675,246	694	302

[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 2002, data from the 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 FERC Form 423.
R = Revised.
Note: MCF equals 1,000 cubic feet. Totals may not equal sum of components because of independent rounding.
Sources: 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 4.6. Receipts and Quality of Coal Delivered for the Electric Power Industry, 1995 through 2006

Period	Anthracite[1]			Bituminous[1]			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight
1995	857	.53	37.4	432,586	1.60	10.2	316,195	.39	6.7	77,222	.99	14.0
1996	735	.52	37.7	454,814	1.64	10.3	328,874	.39	6.6	78,278	.92	13.6
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

[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 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 FERC Form 423.
Note: Totals may not equal sum of components because of independent rounding.
Sources: 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 4.7. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 1995 through 2006

Year	Coal[1]			Petroleum[2]		Natural Gas[3]
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Cubic Foot
1995	10,248	1.08	9.23	149,371	1.21	1,019
1996	10,263	1.10	9.22	149,367	1.26	1,017
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[4]	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

[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 2002, data from the 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 FERC Form 423.

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

Sources: 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."

Chapter 5. Emissions

Table 5.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, 1995 through 2006
(Thousand Metric Tons)

Emission	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Carbon Dioxide (CO_2)	2,459,800	2,513,609	2,456,934	2,415,680	2,395,048	2,389,745	2,441,722[R]	2,338,660[R]	2,324,139[R]	2,232,709[R]	2,161,258[R]	2,083,509[R]
Sulfur Dioxide (SO_2)	9,524	10,340	10,309	10,646	10,881	11,174	11,297	12,444	12,509	13,520	12,906	11,896
Nitrogen Oxides (NO_x)	3,799	3,961	4,143	4,532	5,194	5,290	5,380	5,732	6,237	6,324	6,282	7,885

R = Revised.

Notes: • See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates. • CO_2 emissions for 1995 - 2000 have been revised to reflect the emission factors shown in Table A3.

Table 5.2. Number and Capacity of Fossil-Fueled Steam-Electric Generators with Environmental Equipment, 1995 through 2006

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)
1995	178	84,677	1,134	351,198	471	165,295	1,295	375,691
1996	182	85,842	1,134	352,154	477	166,749	1,299	377,144
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

[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 for 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. • Beginning in 2001, data for plants with combustible renewable steam-electric capacity of 10 megawatts or more were also included. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 5.3. Average Flue Gas Desulfurization Costs, 1995 through 2006

Year	Average Overhead & Maintenance Costs (mills per kilowatthour)[1]	Average Installed Capital Costs (dollars per kilowatt)
1995	1.16	126.00
1996	1.07	128.00
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

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

NA = Not available. Form EIA-767 data collection was suspended for 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 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.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Chapter 6. Trade

Table 6.1. Electric Power Industry - Electricity Purchases, 1995 through 2006
(Thousand Megawatthours)

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
U.S. Total	**5,502,584**	**6,092,285[R]**	**6,569,628[R]**	**6,979,669[R]**	**8,754,807[R]**	**7,555,276[R]**	**2,345,540**	**2,039,969**	**2,020,622**	**1,966,447**	**1,797,720**	**1,617,715**
Electric Utilities	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	1,694,192	1,528,068
Energy-Only Providers	2,793,288	3,250,298	3,741,410	4,264,102	6,050,159	4,412,064	NA	NA	NA	NA	NA	NA
IPP	26,628	12,201[R]	24,258[R]	37,921	15,801	97,357[1]	10,622	4,358	4,089	1,647	7,713	3,760
CHP	77,353	69,744[R]	78,267[R]	67,122	68,135	NA	84,536	86,037	89,334	86,701	95,814	85,887

[1] For 2001, CHP purchases are combined with IPP data above.
NA = Not available.
R = Revised.
Notes: • Energy-only providers are wholesale 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.
Source: 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.

Table 6.2. Electric Power Industry - Electricity Sales for Resale, 1995 through 2006
(Thousand Megawatthours)

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
U.S. Total	**5,493,473**	**6,071,659[R]**	**6,330,099[R]**	**6,920,954[R]**	**8,568,678[R]**	**7,345,319[R]**	**2,355,154**	**1,998,090**	**1,921,858**	**1,838,539**	**1,656,090**	**1,495,015**
Electric Utilities	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	1,431,179	1,276,356
Energy-Only Providers	2,446,104	2,867,048	3,327,299	3,906,220	5,757,283	4,386,632	NA	NA	NA	NA	NA	NA
IPP	1,321,342	1,252,796[R]	1,053,364[R]	1,156,796	943,531	811,998[1]	611,150	335,122	228,617	192,299	194,361	187,453
CHP	27,638	26,105[R]	25,996[R]	33,909	28,963	NA	28,421	27,354	29,160	29,922	30,550	31,206

[1] For 2001, CHP sales are combined with IPP data above.
NA = Not available.
R = Revised.
Notes: • Energy-only providers are wholesale 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.
Source: 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.

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1995 through 2006
(Megawatthours)

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Electricity Imports and Exports												
Canada												
Imports	41,544,052	42,930,212	33,007,487	29,319,707	36,536,479	38,401,598	48,515,476	42,911,308	39,502,108	43,008,501	42,233,376	40,596,119
Exports	23,405,387	19,332,124	22,482,109	23,582,184	15,231,079	16,105,612	12,684,706	12,953,488	11,683,276	7,470,332	1,986,361	2,468,244
Mexico												
Imports[1]	1,147,258	1,597,275	1,202,576	1,069,926	242,596	98,649	76,800	303,439	11,249	22,729	1,263,152	2,257,411
Exports	865,948	470,731	415,754	390,190	564,603	367,680	2,144,676	1,268,284	1,973,203	1,503,707	1,315,625	1,154,421
Total Imports	**42,691,310**	**44,527,487**	**34,210,063**	**30,389,633**	**36,779,077**	**38,500,247**	**48,592,276**	**43,214,747**	**39,513,357**	**43,031,230**	**43,496,528**	**42,853,530**
Total Exports	**24,271,335**	**19,802,855**	**22,897,863**	**23,972,374**	**15,795,681**	**16,473,292**	**14,829,382**	**14,221,772**	**13,656,479**	**8,974,039**	**3,301,986**	**3,622,665**

[1] Includes contract terminations in 1997 and 2000.
Note: Totals may not equal sum of components because of independent rounding.
Source: 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.

Chapter 7. Retail Customers, Sales, and Revenue

Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1995 through 2006
(Number)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
			Total Electric Industry			
1995	103,917,312	12,949,365	580,626	NA	882,422	118,329,725
1996	105,343,005	13,181,065	586,198	NA	893,884	120,004,152
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
			Full-Service Providers[1]			
1995	103,917,312	12,949,365	580,626	NA	882,422	118,329,725
1996	105,341,408	13,180,632	586,169	NA	893,884	120,002,093
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
			Energy-Only Providers			
1995	--	--	--	--	--	--
1996	1,597	433	29	NA	0	2,059
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

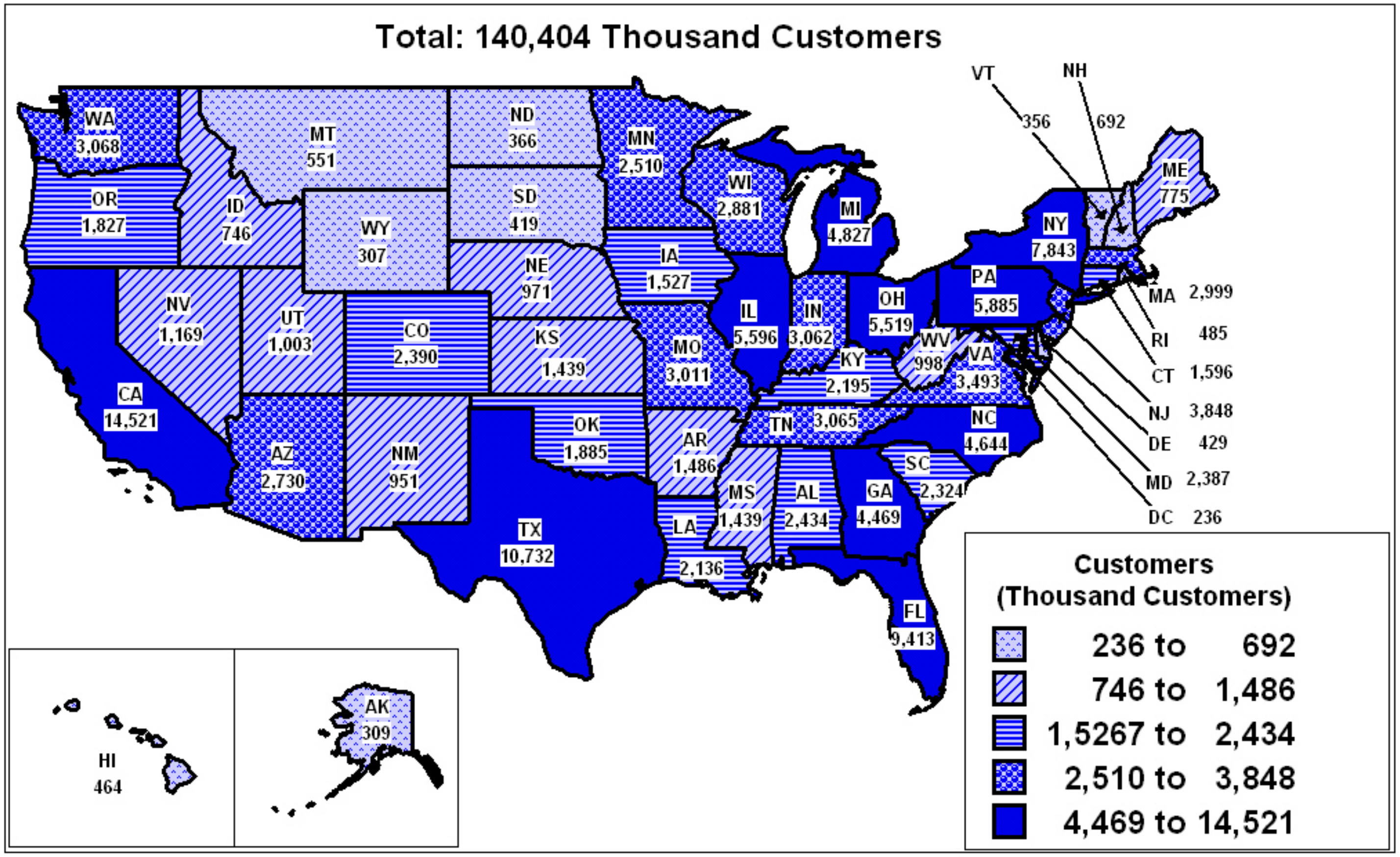
[1] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so they are included under "Full-Service Providers."

NA = Not available.

Note: See Technical Notes reference for definitions.

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

Figure 7.1. U.S. Electric Industry Total Ultimate Customers by State, 2006



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

Source: 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, 1995 through 2006

(Megawatthours)

Period	Sales						Direct Use[1]	Total End Use
	Residential	Commercial	Industrial	Transportation	Other	Total		
Total Electric Industry								
1995	1,042,501,471	862,684,775	1,012,693,350	NA	95,406,993	3,013,286,589	150,676,540	3,163,963,129
1996	1,082,511,751	887,445,174	1,033,631,379	NA	97,538,719	3,101,127,023	152,638,016	3,253,765,039
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[R]	3,810,984,044[R]
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
Full-Service Providers[2]								
1995	1,042,501,471	862,684,775	1,012,693,350	NA	95,406,993	3,013,286,589	NA	3,013,286,589
1996	1,082,490,541	887,424,657	1,030,356,028	NA	97,538,719	3,097,809,945	NA	3,097,809,945
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
Energy-Only Providers								
1995	--	--	--	--	--	--	--	--
1996	21,210	20,517	3,275,351	NA	0	3,317,078	NA	3,317,078
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

[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 fully-bundled energy and delivery services, so are included under "Full-Service Providers."

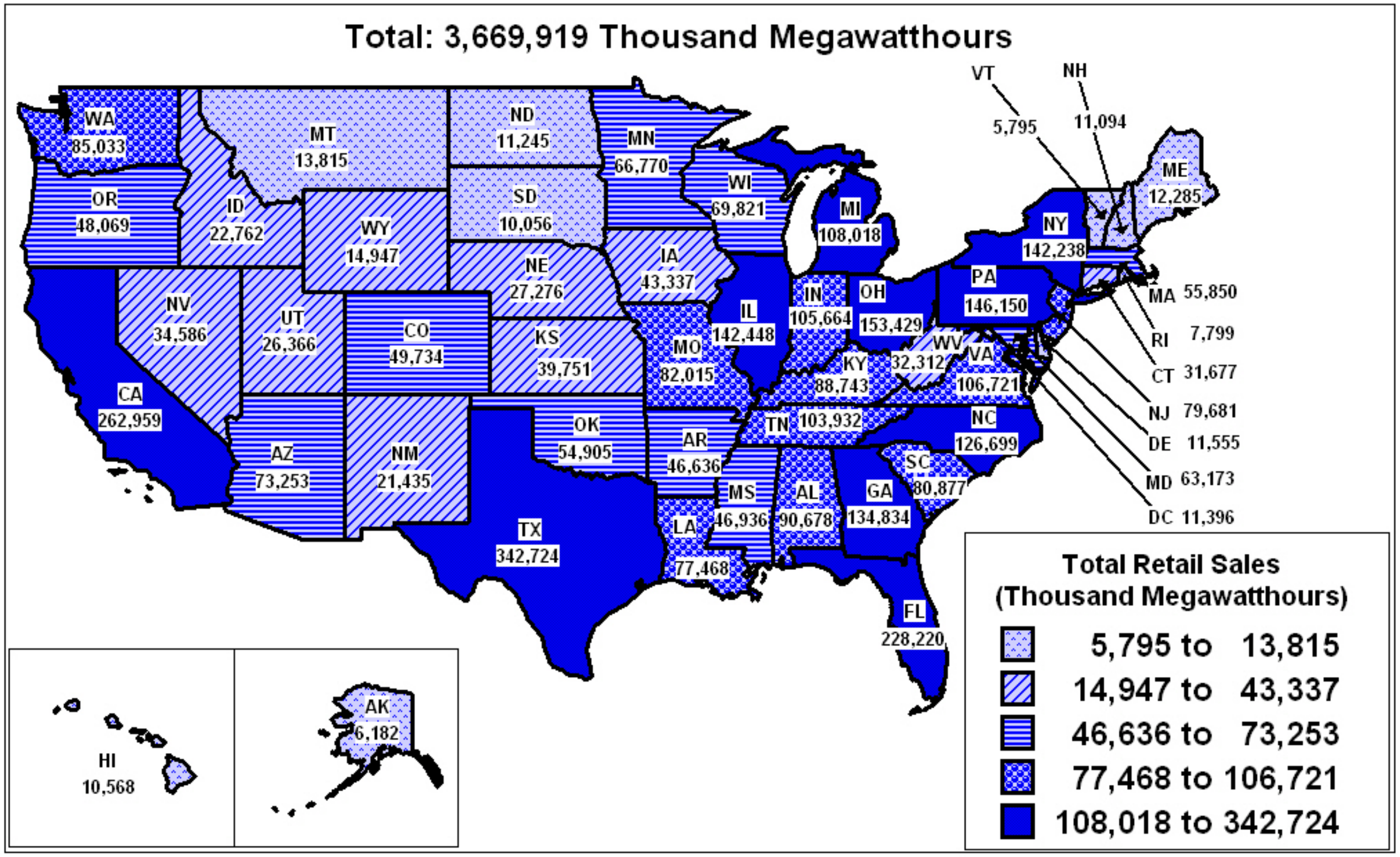
NA = Not available.

R = Revised.

Note: See Technical Notes reference for definitions.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report;" 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, 2006



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

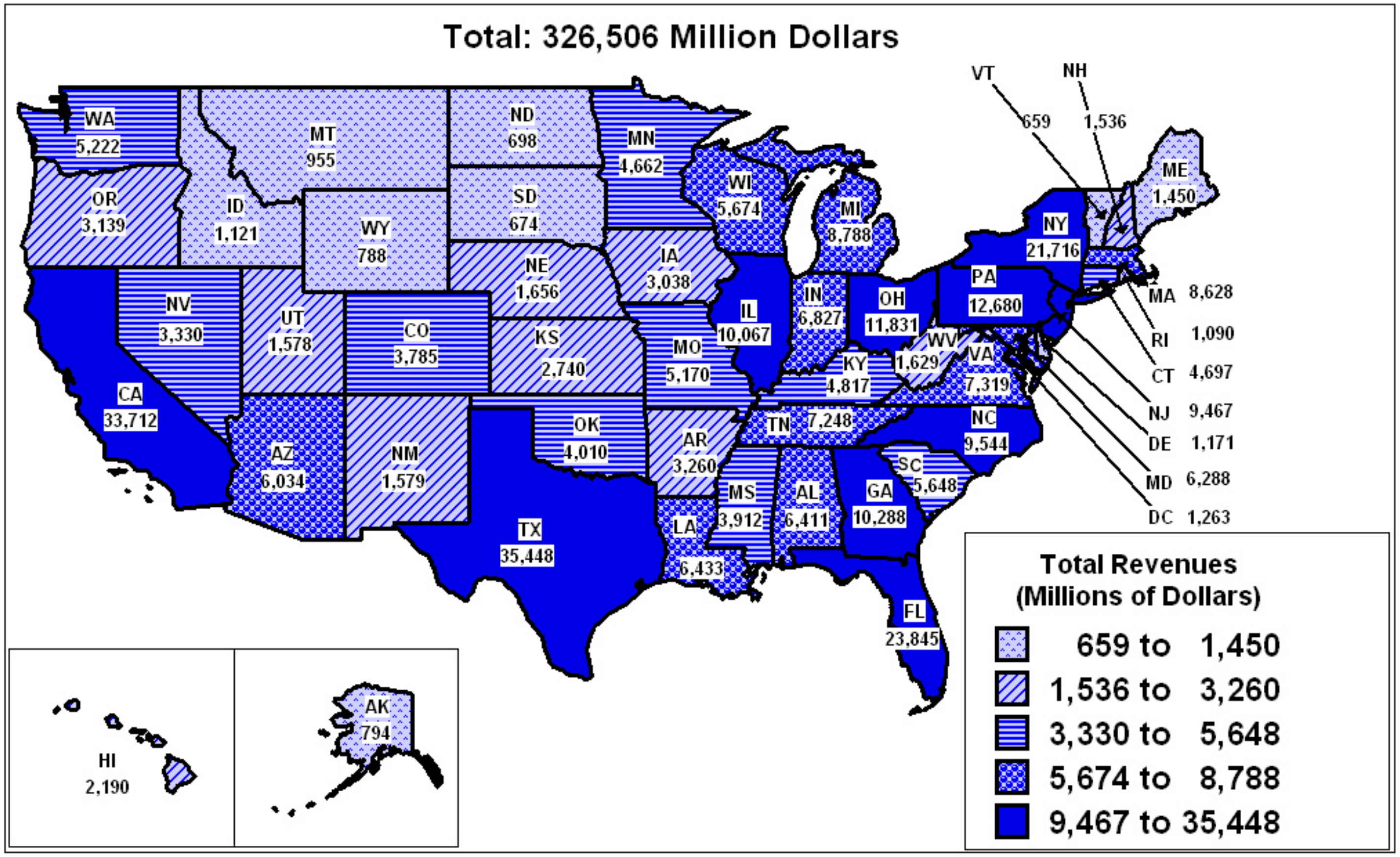
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 7.3. Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1995 through 2006
(Million Dollars)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1995	87,610	66,365	47,175	NA	6,567	207,717
1996	90,503	67,829	47,536	NA	6,741	212,609
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
Full-Service Providers[1]						
1995	87,610	66,365	47,175	NA	6,567	207,717
1996	90,501	67,827	47,385	NA	6,741	212,455
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
Energy-Only Providers[2]						
1995	--	--	--	--	--	--
1996	2	2	151	NA	0	154
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
Delivery-Only Service						
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
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

[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 fully-bundled energy and delivery services, so are included under "Full-Service Providers."
[2] 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. • 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, 2006



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

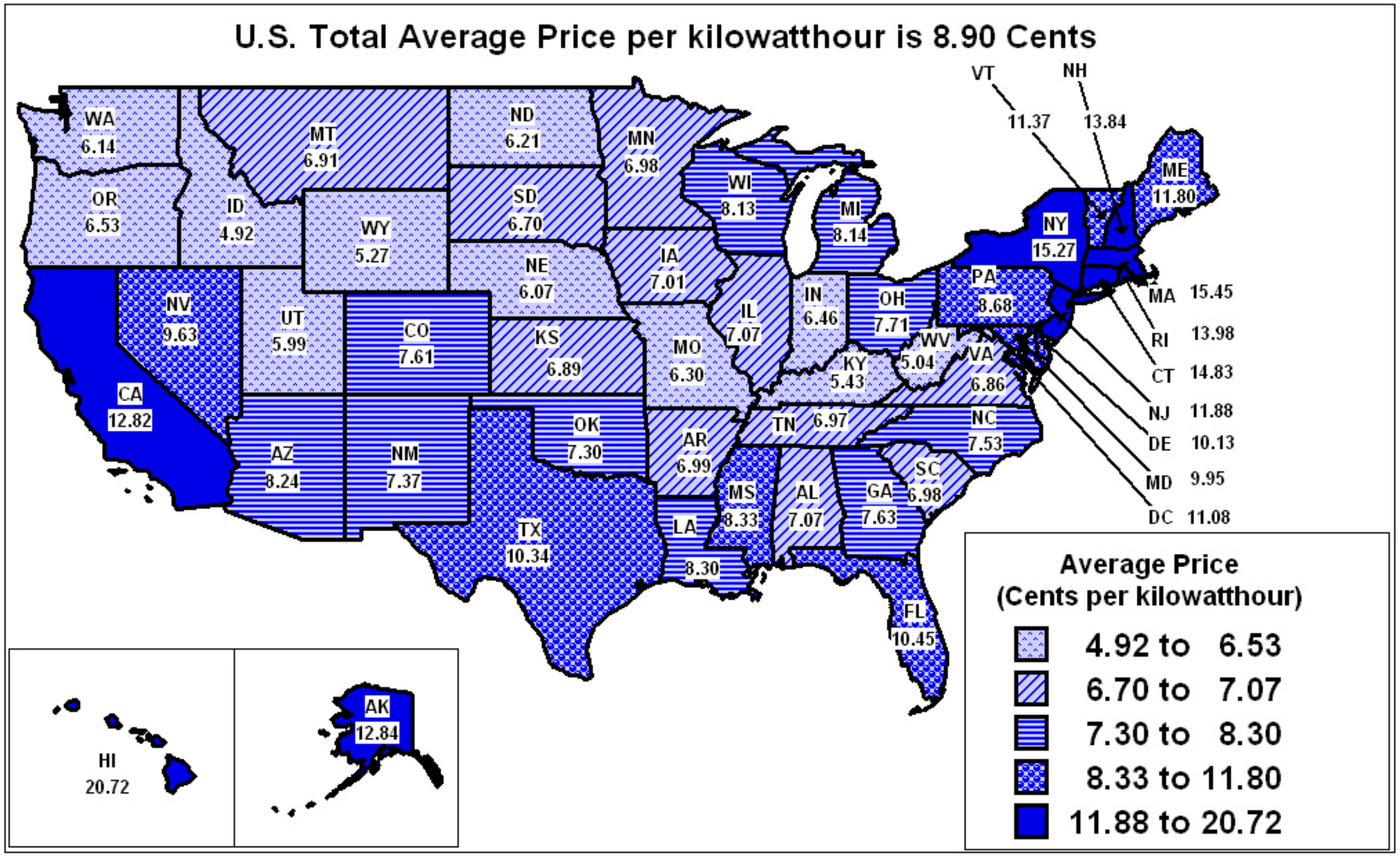
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 7.4. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, 1995 through 2006
(Cents per kilowatthour)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1995	8.40	7.69	4.66	NA	6.88	6.89
1996	8.36	7.64	4.60	NA	6.91	6.86
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
Full-Service Providers[1]						
1995	8.40	7.69	4.66	NA	6.88	6.89
1996	8.36	7.64	4.60	NA	6.91	6.86
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
Energy-Only Providers[2]						
1995	--	--	--	--	--	--
1996	8.36	7.64	4.60	NA	--	6.86
1997	8.43	7.59	4.53	NA	--	6.85
1998	8.26	7.41	4.48	NA	--	6.74
1999	8.16	7.26	4.43	NA	6.35	6.66
2000	12.07	8.65	6.24	NA	11.42	7.97
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
Delivery-Only Service						
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	--	--	--	--	--	--
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

[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 fully-bundled energy and delivery services, so are included under "Full-Service Providers."
[2] From 1996 to 1999, average revenue was estimated based on retail sales reported on the Form EIA-861.
NA = Not available.
Note: See Glossary reference for definitions.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

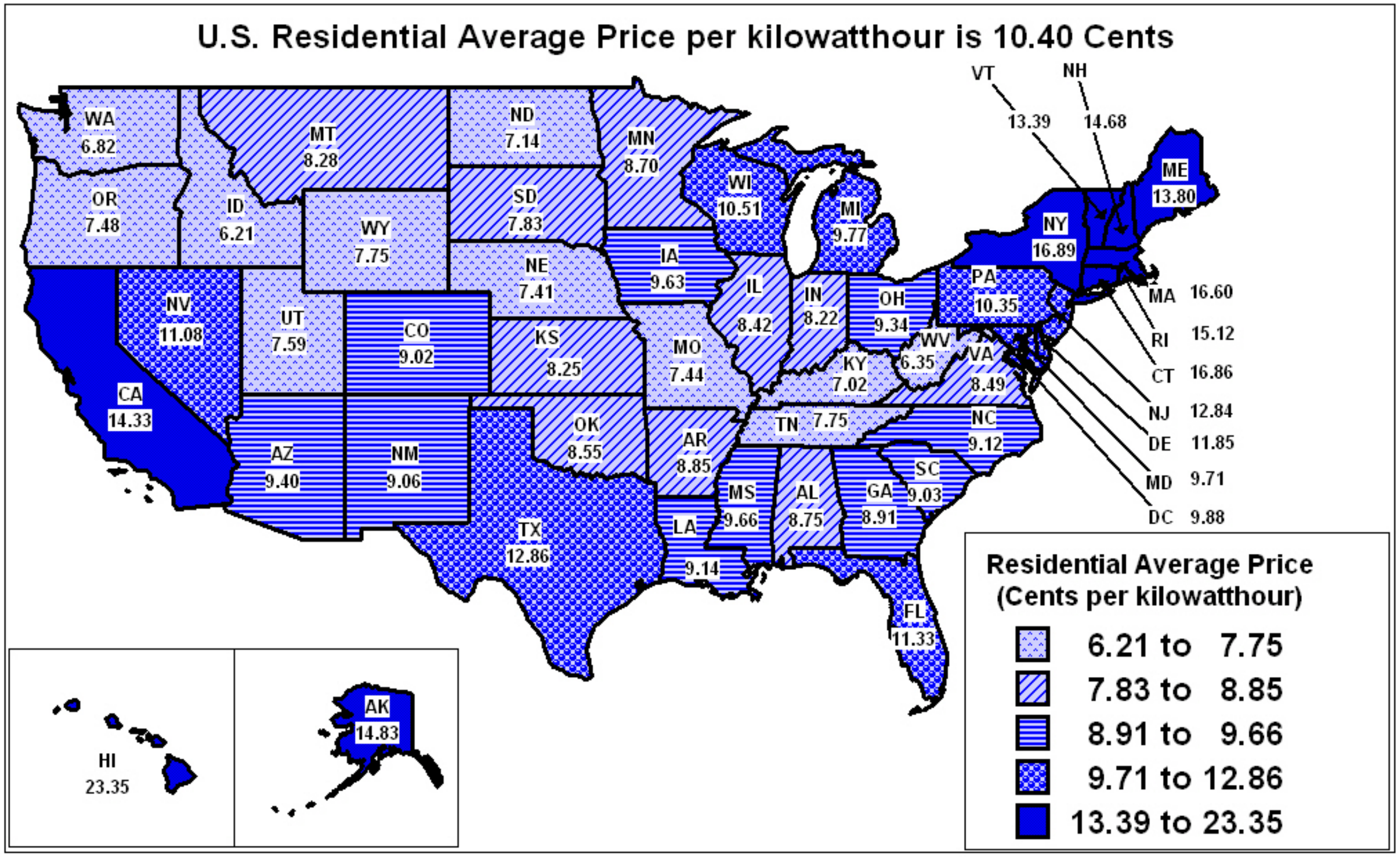
Figure 7.4. Average Retail Price of Electricity by State, 2006



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

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

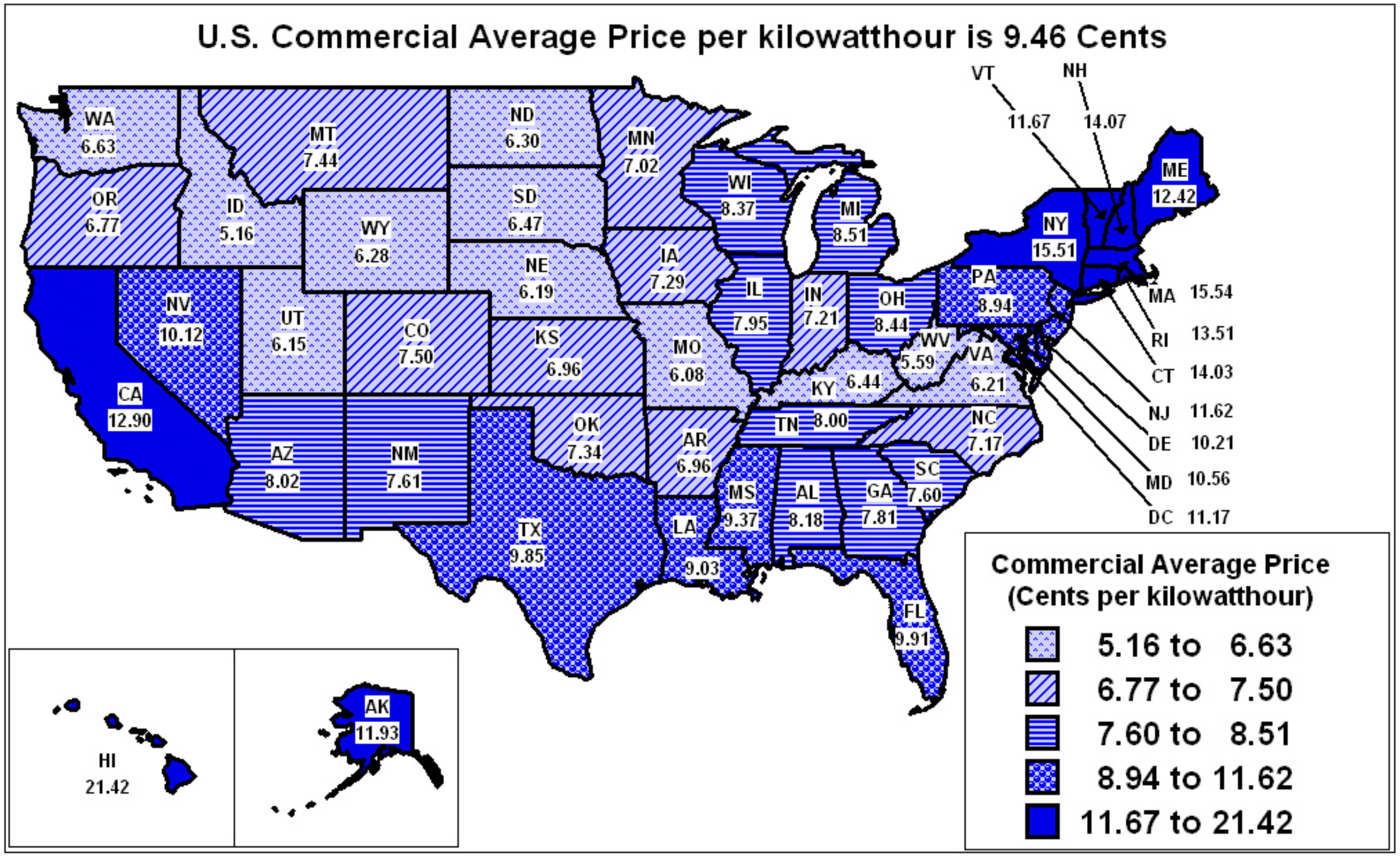
Figure 7.5. Average Residential Price of Electricity by State, 2006



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

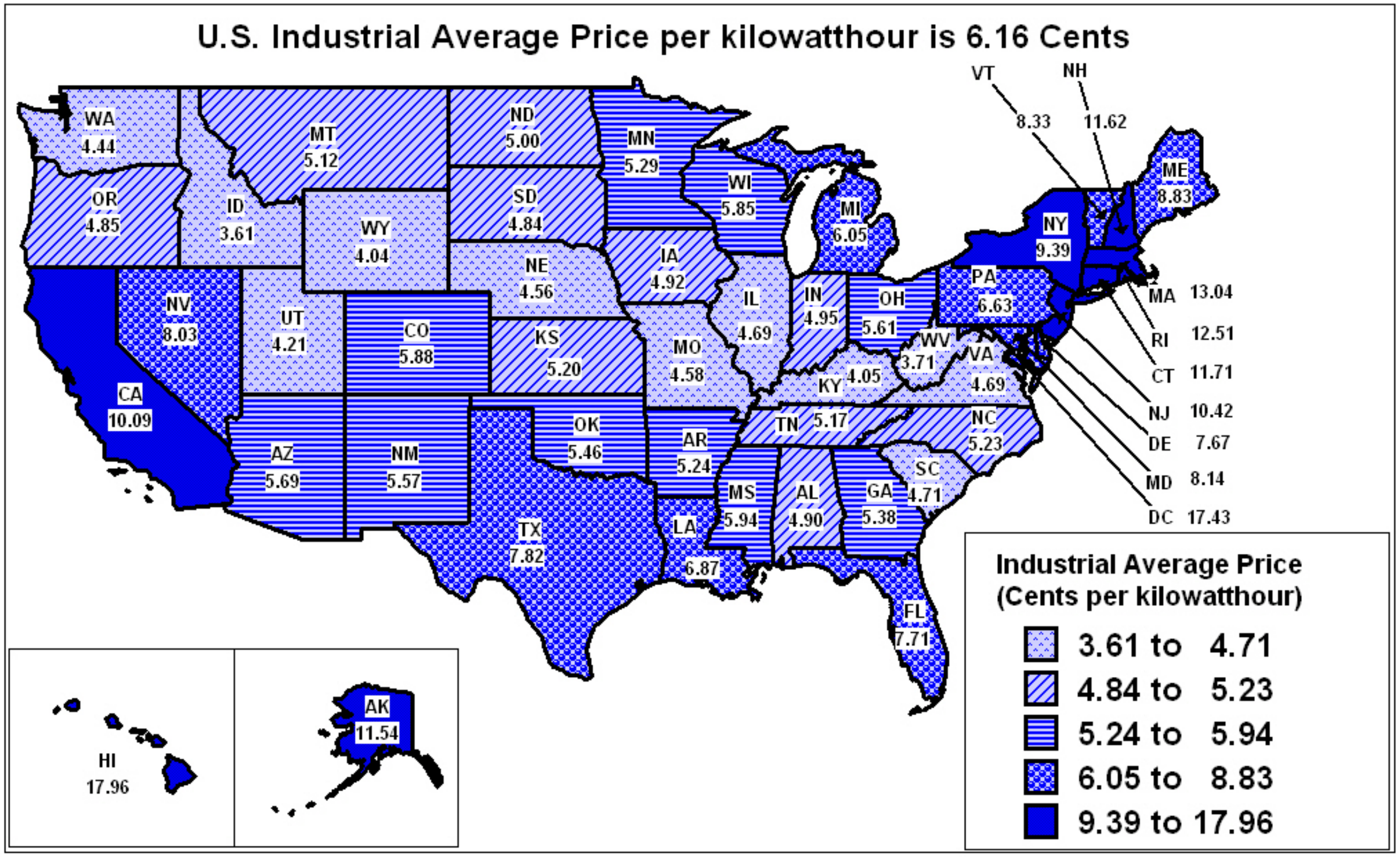
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.6. Average Commercial Price of Electricity by State, 2006



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

Figure 7.7. Average Industrial Price of Electricity by State, 2006



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

Source: 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 - 2006

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	609,213	35,954	645,167	31,323	3,146	34,469

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, 1995 through 2006
(Million Dollars)

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Utility Operating Revenues	**277,142**	**267,534**	**240,318**	**226,227**	**219,389**	**267,525**	**235,336**	**214,160**	**218,175**	**215,083**	**207,459**	**199,967**
Electric Utility	247,503	235,570	213,539	202,369	200,135	244,219	214,707	197,578	201,970	195,898	188,901	183,655
Other Utility	29,639	31,964	26,779	23,858	19,254	23,306	20,630	16,583	16,205	19,185	18,558	16,312
Utility Operating Expenses	**247,170**	**238,590**	**207,161**	**197,459**	**188,745**	**235,198**	**210,324**	**182,258**	**186,498**	**182,796**	**173,920**	**165,321**
Electric Utility	219,171	208,461	182,337	175,473	171,291	213,733	191,329	167,266	171,689	165,443	156,938	150,599
Operation	159,472	151,150	131,962	122,723	116,374	159,929	132,662	108,461	110,759	104,337	97,207	91,881
Production	128,016	121,058	104,287	96,181	90,649	136,089	107,352	83,555	85,956	80,153	73,437	68,983
Cost of Fuel	38,158	36,161	28,678	26,476	24,132	29,490	32,555	29,826	31,252	31,861	30,706	29,122
Purchased Power	79,485	78,279	67,354	62,173	58,828	98,231	61,969	43,258	42,612	37,991	32,987	29,981
Other	10,399	6,638	8,256	7,532	7,688	8,368	12,828	10,470	12,092	10,301	9,744	9,880
Transmission	6,185	5,687	4,519	3,585	3,494	2,365	2,699	2,423	2,197	1,915	1,503	1,425
Distribution	3,658	3,517	3,301	3,185	3,113	3,217	3,115	2,956	2,804	2,700	2,604	2,561
Customer Accounts	4,424	4,243	4,087	4,180	4,165	4,434	4,246	4,195	4,021	3,767	3,848	3,613
Customer Service	2,533	2,289	2,012	1,893	1,821	1,856	1,839	1,889	1,955	1,917	1,920	1,922
Sales	241	219	238	234	261	282	403	492	514	501	435	348
Administrative and General	14,618	14,113	13,519	13,466	12,872	11,686	13,009	12,951	13,311	13,384	13,458	13,028
Maintenance	12,879	12,058	11,774	11,141	10,843	11,167	12,185	12,276	12,486	12,368	12,050	11,767
Depreciation	17,438	17,177	16,373	16,962	17,319	20,845	22,761	23,968	24,122	23,072	21,194	19,885
Taxes and Other	28,187	26,848	22,228	24,648	26,755	21,792	23,721	22,561	24,322	25,667	26,488	27,065
Other Utility	27,999	30,129	24,823	21,986	17,454	21,465	18,995	14,992	14,809	17,353	16,983	14,722
Net Utility Operating Income	**29,972**	**28,944**	**33,158**	**28,768**	**30,644**	**32,327**	**25,012**	**31,902**	**31,677**	**32,286**	**33,539**	**34,646**

Note: 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, 1995 through 2006
(Mills per Kilowatthour)

Plant Type	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Operation												
Nuclear	8.93	8.39	8.30	8.86	8.54	8.30	8.41	8.93	9.98	11.02	9.47	9.43
Fossil Steam	3.23	2.97	2.68	2.50	2.54	2.40	2.31	2.21	2.17	2.22	2.25	2.38
Hydroelectric[1]	5.11	5.26	5.05	4.50	5.07	5.79	4.74	4.17	3.85	3.29	3.87	3.69
Gas Turbine and Small Scale[2]	3.00	2.97	2.73	2.76	2.72	3.15	4.57	5.16	3.85	4.43	5.08	3.57
Maintenance												
Nuclear	5.68	5.23	5.38	5.23	5.04	5.01	4.93	5.13	5.79	6.90	5.68	5.21
Fossil Steam	3.19	2.96	2.96	2.73	2.68	2.61	2.45	2.38	2.41	2.43	2.49	2.65
Hydroelectric[1]	3.44	3.60	3.64	3.01	3.58	3.97	2.99	2.60	2.00	2.49	2.08	2.19
Gas Turbine and Small Scale[2]	2.29	2.15	2.16	2.26	2.38	3.33	3.50	4.80	3.43	3.43	4.98	4.28
Fuel												
Nuclear	4.85	4.54	4.58	4.60	4.60	4.67	4.95	5.17	5.39	5.42	5.50	5.75
Fossil Steam	23.17	21.77	18.21	17.35	16.11	18.13	17.69	15.62	15.94	16.80	16.51	16.07
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small Scale[2]	52.46	53.73	45.20	43.91	31.82	43.56	39.19	28.72	23.02	24.94	30.58	20.83
Total												
Nuclear	19.46	18.16	18.26	18.69	18.18	17.98	18.28	19.23	21.16	23.33	20.65	20.39
Fossil Steam	29.59	27.69	23.85	22.59	21.32	23.14	22.44	20.22	20.52	21.45	21.25	21.11
Hydroelectric[1]	8.54	8.86	8.69	7.51	8.65	9.76	7.73	6.77	5.86	5.78	5.95	5.89
Gas Turbine and Small Scale[2]	57.75	58.85	50.10	48.93	36.93	50.04	47.26	38.68	30.30	32.80	40.64	28.67

[1] Conventional hydro and pumped storage.

[2] Gas turbine, internal combustion, photovoltaic, and wind plants.

Notes: • 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), 1995 through 2006
(Million Dollars)

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Operating Revenue - Electric	**NA**	**NA**	**NA**	**33,906**	**32,776**	**38,028**	**31,843**	**26,767**	**26,155**	**25,397**	**24,207**	**23,473**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**29,637**	**28,638**	**32,789**	**26,244**	**21,274**	**20,880**	**20,425**	**19,084**	**18,959**
Operation Including Fuel	**NA**	**NA**	**NA**	**22,642**	**21,731**	**25,922**	**19,575**	**15,386**	**15,120**	**14,917**	**13,768**	**13,653**
Production	NA	NA	NA	17,948	17,176	21,764	15,742	11,923	11,608	11,481	11,080	10,385
Transmission	NA	NA	NA	872	858	785	781	732	773	725	344	628
Distribution	NA	NA	NA	696	680	605	574	516	603	538	497	426
Customer Accounts	NA	NA	NA	582	537	600	507	415	390	390	365	323
Customer Service	NA	NA	NA	280	315	263	211	160	127	133	103	102
Sales	NA	NA	NA	84	74	73	66	49	51	46	18	20
Administrative and General	NA	NA	NA	2,180	2,090	1,832	1,695	1,591	1,567	1,602	1,360	1,769
Maintenance	**NA**	**NA**	**NA**	**2,086**	**1,926**	**1,904**	**1,815**	**1,686**	**1,631**	**1,609**	**1,638**	**1,575**
Depreciation and Amortization	**NA**	**NA**	**NA**	**3,844**	**3,907**	**4,009**	**3,919**	**3,505**	**3,459**	**3,239**	**3,160**	**2,934**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**1,066**	**1,074**	**954**	**936**	**697**	**670**	**660**	**662**	**797**
Net Electric Operating Income	**NA**	**NA**	**NA**	**4,268**	**4,138**	**5,238**	**5,598**	**5,493**	**5,275**	**4,972**	**5,123**	**4,514**

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), 1995 through 2006
(Million Dollars)

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Operating Revenue - Electric	**NA**	**NA**	**NA**	**12,454**	**11,546**	**10,417**	**9,904**	**9,354**	**8,790**	**8,586**	**8,582**	**8,435**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**11,481**	**10,703**	**9,820**	**9,355**	**8,737**	**8,245**	**8,033**	**8,123**	**7,979**
Operation Including Fuel	**NA**	**NA**	**NA**	**10,095**	**9,439**	**8,864**	**8,424**	**7,874**	**7,437**	**7,117**	**7,359**	**7,173**
Production	NA	NA	NA	8,865	8,311	7,863	7,486	7,015	6,661	6,240	6,578	6,422
Transmission	NA	NA	NA	105	93	61	64	48	44	57	51	35
Distribution	NA	NA	NA	348	320	311	280	261	230	304	234	204
Customer Accounts	NA	NA	NA	172	163	164	155	143	130	139	141	125
Customer Service	NA	NA	NA	31	39	26	22	22	21	16	18	18
Sales	NA	NA	NA	11	10	15	16	14	9	13	12	10
Administrative and General	NA	NA	NA	562	504	423	402	371	342	348	325	358
Maintenance	**NA**	**NA**	**NA**	**418**	**389**	**304**	**286**	**272**	**263**	**338**	**244**	**250**
Depreciation and Amortization	**NA**	**NA**	**NA**	**711**	**631**	**405**	**394**	**369**	**330**	**354**	**322**	**313**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**257**	**244**	**247**	**251**	**223**	**215**	**225**	**206**	**244**
Net Electric Operating Income	**NA**	**NA**	**NA**	**974**	**843**	**597**	**549**	**617**	**545**	**552**	**459**	**457**

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, 1995 through 2006
(Million Dollars)

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Operating Revenue - Electric	**NA**	**NA**	**NA**	**11,798**	**11,470**	**12,458**	**10,685**	**10,186**	**9,780**	**8,833**	**9,082**	**8,743**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**8,763**	**8,665**	**10,013**	**8,139**	**7,775**	**7,099**	**5,999**	**6,390**	**6,162**
Operation Including Fuel	**NA**	**NA**	**NA**	**6,498**	**6,419**	**7,388**	**5,873**	**5,412**	**5,184**	**4,073**	**4,514**	**4,615**
Production	NA	NA	NA	5,175	5,236	6,247	5,497	4,890	4,735	3,686	4,109	4,219
Transmission	NA	NA	NA	307	244	354	332	349	323	327	328	290
Distribution	NA	NA	NA	1	1	1	2	2	2	1	1	2
Customer Accounts	NA	NA	NA	4	10	16	6	1	1	1	3	2
Customer Service	NA	NA	NA	63	60	60	48	50	51	42	46	29
Sales	NA	NA	NA	20	6	6	10	28	14	13	7	41
Administrative and General	NA	NA	NA	927	862	705	467	528	535	444	451	431
Maintenance	**NA**	**NA**	**NA**	**600**	**566**	**521**	**488**	**436**	**476**	**441**	**432**	**398**
Depreciation and Amortization	**NA**	**NA**	**NA**	**1,335**	**1,351**	**1,790**	**1,471**	**1,623**	**1,175**	**1,214**	**1,187**	**896**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**329**	**328**	**315**	**308**	**304**	**264**	**272**	**256**	**252**
Net Electric Operating Income	**NA**	**NA**	**NA**	**3,035**	**2,805**	**2,445**	**2,546**	**2,411**	**2,681**	**2,834**	**2,692**	**2,581**

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, 1995 through 2006
(Million Dollars)

Description	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Operating Revenue - Electric	**NA**	**34,088**	**30,650**	**29,228**	**27,458**	**26,458**	**25,629**	**23,824**	**23,988**	**23,321**	**24,424**	**24,609**
Operation and Maintenance Expenses	**NA**	**31,209**	**27,828**	**26,361**	**24,561**	**23,763**	**22,982**	**21,283**	**21,223**	**20,715**	**23,149**	**21,741**
Operation Including Fuel	**NA**	**28,723**	**25,420**	**24,076**	**22,383**	**21,703**	**20,942**	**19,336**	**19,280**	**18,405**	**20,748**	**19,334**
Production	NA	23,921	20,752	19,559	18,143	17,714	17,080	15,706	15,683	15,105	17,422	15,907
Transmission	NA	679	665	637	579	524	525	466	452	339	372	366
Distribution	NA	1,895	1,860	1,787	1,681	1,589	1,530	1,451	1,440	1,134	1,133	1,127
Customer Accounts	NA	612	595	579	545	532	487	455	446	382	375	383
Customer Service	NA	147	141	140	136	119	133	132	132	118	118	112
Sales	NA	76	80	79	79	88	82	81	77	61	72	72
Administrative and General	NA	1,393	1,327	1,295	1,219	1,137	1,104	1,045	1,050	1,266	1,257	1,367
Depreciation and Amortization	**NA**	**2,253**	**2,182**	**2,076**	**1,992**	**1,895**	**1,820**	**1,747**	**1,732**	**1,727**	**1,787**	**1,778**
Taxes and Tax Equivalents	**NA**	**234**	**226**	**209**	**186**	**164**	**220**	**200**	**211**	**583**	**614**	**628**
Net Electric Operating Income	**NA**	**2,879**	**2,822**	**2,867**	**2,897**	**2,696**	**2,647**	**2,541**	**2,764**	**2,606**	**2,872**	**2,868**

NA = Not available.
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, 1995 through 2006
(Megawatts)

Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Total Actual Peak Load Reduction	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**
Energy Efficiency	15,959	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243	13,212
Load Management	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,347

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 9.2. Demand-Side Management Program Annual Effects by Program Category, 1995 through 2006

Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
	Annual Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	15,959	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243	13,212
Energy Savings (Thousand MWh)	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328
	Annual Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,347
Potential Peak Load Reductions (MW)	21,270	21,282	20,998	25,290	26,888	27,730	28,496	30,118	27,840	27,911	34,101	33,817
Energy Savings (Thousand MWh)	865	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989	2,093

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, 1995 through 2006

Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
	Incremental Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	1,177	1,403	1,521	945	1,054	999	720	695	796	1,065	1,381	1,561
Energy Savings (Thousand MWh)	5,385	5,872	4,522	2,939	3,543	4,402	3,284	3,027	3,324	4,661	6,361	7,901
Small Utilities												
Actual Peak Load Reduction (MW)	91	302	204	90	49	20	25	22	12	12	2	7
Energy Savings (Thousand MWh)	9	7	10	8	192	8	8	8	37	10	7	16
	Incremental Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	1,495	1,009	907	1,084	1,160	1,297	919	1,568	1,821	1,261	5,027	3,039
Potential Peak Load Reductions (MW)	2,544	2,005	2,622	1,981	2,655	2,448	2,439	6,457	2,832	2,475	2,309	4,930
Energy Savings (Thousand MWh)	95	133	2	29	65	79	63	67	37	171	482	321
Small Utilities												
Actual Peak Load Reduction (MW)	195	153	242	81	54	45	137	54	124	130	50	29
Potential Peak Load Reductions (MW)	273	218	422	131	76	177	190	84	160	183	90	41
Energy Savings (Thousand MWh)	4	5	4	4	2	4	9	2	7	19	6	3

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, 1995 through 2006

Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
	Actual Peak Load Reductions (MW)											
Large Utilities												
Residential	10,730	9,432	8,870	9,431	9,137	9,619	9,446	9,976	9,327	10,799	11,471	10,930
Commercial	7,779	7,926	7,194	6,774	6,839	8,210	6,987	7,777	9,482	8,174	8,678	8,057
Industrial	8,692	8,343	7,454	6,594	6,500	6,553	6,141	6,360	7,927	5,812	9,083	10,033
Transportation	39	9	14	105	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	460	573	327	2,342	495	498	661	545
Total	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**
	Potential Peak Load Reductions (MW)											
Large Utilities												
Residential	13,040	12,097	11,967	12,525	12,072	12,274	12,970	12,812	13,022	16,662	14,697	14,047
Commercial	10,006	10,214	9,624	8,943	9,298	10,469	9,114	8,868	12,210	12,896	12,452	11,495
Industrial	14,119	14,260	13,665	17,298	18,321	17,344	18,775	17,237	15,512	11,035	20,275	20,715
Transportation	64	62	14	105	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	617	670	510	4,653	686	644	921	772
Total	**37,229**	**36,633**	**35,270**	**38,871**	**40,308**	**40,757**	**41,369**	**43,570**	**41,430**	**41,237**	**48,344**	**47,029**
	Energy Savings (Thousand MWh)											
Large Utilities												
Residential	21,437	19,255	17,763	13,469	15,438	16,027	16,287	16,263	16,564	17,830	20,585	20,253
Commercial	28,982	28,416	24,624	25,089	24,391	24,217	25,660	23,375	25,125	27,898	29,186	26,187
Industrial	13,348	12,178	12,273	11,156	11,339	10,487	9,160	8,156	3,347	8,684	10,493	9,620
Transportation	50	48	51	551	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	2,907	3,206	2,593	2,770	831	1,694	1,578	1,360
Total	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**

NA = Not available.

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, 1995 through 2006

Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
					Actual Peak Load Reductions (MW)							
Large Utilities												
Residential	1,012	966	1,361	640	895	790	572	605	599	743	792	860
Commercial	759	715	560	528	527	742	515	684	1,176	699	935	1,176
Industrial	901	731	507	849	680	640	502	929	799	836	1,870	2,426
Transportation	0	0	0	12	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	112	124	50	45	43	48	93	139
Total	**2,672**	**2,412**	**2,428**	**2,029**	**2,214**	**2,296**	**1,640**	**2,263**	**2,617**	**2,326**	**3,690**	**4,601**
Small Utilities												
Residential	131	325	280	88	48	32	37	27	35	40	30	20
Commercial	63	71	126	58	41	15	37	22	34	21	9	10
Industrial	92	59	40	25	12	16	62	7	56	61	8	4
Transportation	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	0	0	26	19	10	20	5	2
Total	**286**	**455**	**446**	**171**	**101**	**63**	**162**	**76**	**136**	**142**	**52**	**36**
U.S. Total	**2,958**	**2,867**	**2,874**	**2,200**	**2,317**	**2,361**	**1,802**	**2,339**	**2,753**	**2,468**	**3,742**	**4,637**
					Potential Peak Load Reductions (MW)							
Large Utilities												
Residential	1,406	1,311	1,680	752	1,311	900	699	753	751	960	950	1,231
Commercial	1,114	1,098	894	602	751	1,115	565	718	1,863	853	1,512	1,697
Industrial	1,201	999	1,569	1,551	1,506	1,277	1,815	5,612	1,438	1,669	3,800	3,368
Transportation	0	0	0	21	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	141	155	79	68	76	58	146	195
Total	**3,721**	**3,408**	**4,143**	**2,926**	**3,709**	**3,447**	**3,159**	**7,151**	**3,628**	**3,540**	**6,408**	**6,491**
Small Utilities												
Residential	164	367	395	116	64	158	55	41	49	59	46	27
Commercial	95	100	154	73	43	19	51	25	41	35	17	13
Industrial	105	53	77	32	15	18	64	9	70	72	16	6
Transportation	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	3	2	44	31	12	30	13	2
Total	**364**	**520**	**626**	**221**	**125**	**197**	**215**	**106**	**172**	**196**	**92**	**48**
U.S. Total	**4,085**	**3,928**	**4,769**	**3,147**	**3,834**	**3,644**	**3,374**	**7,257**	**3,800**	**3,736**	**6,500**	**6,539**
					Energy Savings (Thousand MWh)							
Large Utilities												
Residential	2,141	2,276	1,842	868	1,203	1,365	856	990	909	1,055	1,179	1,630
Commercial	2,339	2,638	1,815	1,356	1,583	1,867	1,780	1,502	1,703	2,382	3,537	4,594
Industrial	999	1,090	867	732	706	872	547	475	645	1,059	1,787	1,678
Transportation	0	*	0	12	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	116	376	164	127	104	336	341	320
Total	**5,479**	**6,004**	**4,524**	**2,968**	**3,608**	**4,481**	**3,347**	**3,094**	**3,361**	**4,832**	**6,844**	**8,222**
Small Utilities												
Residential	9	6	6	7	45	5	9	4	8	10	7	9
Commercial	3	5	7	5	148	3	4	3	6	3	3	5
Industrial	1	*	2	1	2	2	1	1	3	8	2	5
Transportation	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	*	3	3	1	1	7	1	2
Total	**13**	**12**	**14**	**13**	**194**	**13**	**17**	**9**	**18**	**28**	**13**	**21**
U.S. Total	**5,492**	**6,016**	**4,539**	**2,981**	**3,802**	**4,492**	**3,364**	**3,103**	**3,379**	**4,860**	**6,857**	**8,243**

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

NA = Not available.

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, 1995 through 2006
(Thousand Megawatthours)

Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Total Energy Savings	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**
Energy Efficiency	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328
Load Management	865	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989	2,093

Note: 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, 1995 through 2006
(Thousand Dollars)

Item	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Direct Cost[1]	**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**	**1,623,588**	**2,004,942**
Energy Efficiency	1,258,158	1,169,241	910,115	807,403	1,007,323	1,097,504	938,666	820,108	766,384	892,468	1,051,922	1,408,542
Load Management	665,733	625,568	515,057	352,137	413,614	358,098	445,566	430,581	466,634	454,777	571,666	596,400
Indirect Cost[2]	**127,499**	**126,543**	**132,294**	**137,670**	**204,600**	**174,684**	**180,669**	**172,955**	**187,902**	**288,775**	**278,609**	**416,342**
Total DSM Cost[3]	**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**	**1,902,197**	**2,421,284**

[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.
Notes: • 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 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, Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), Energy Information Administration (EIA), U.S. Department of Energy (DOE). The CNEAF office 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 either received on paper forms or entered directly by respondents into CNEAF's Internet Data Collection System (IDC). Hard copy forms are keyed by EIA into the IDC. All data are subject to review via edits built into the IDC, 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 IDC 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 email. 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 email contact with the respondents.

Reliability of Data

Annual survey data have nonsampling errors. Nonsampling 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.

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 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.

Imputation. If the reported electric generation appeared to be in error and the data issue could not be resolved with the respondent, or if the facility was a non-respondent, a regression methodology was used to impute for generation for the facility. The same procedure is used to estimate ("predict") data for facilities not in the monthly sample. The regression methodology relies on other data to make estimates for erroneous or missing responses. Beginning with data for 2006, the final numbers published in the *Electric Power Annual* reflect the use of a multiple regression for imputation. Regressor data are the prior year generation for the same fuel, nameplate capacity (from Form EIA-860), and prior year generation for all other fuels. Data from prior time frames, including 2006 preliminary numbers as published in the *Electric Power Monthly*, used only prior year generation for the same fuel in the regression.

The basic technique employed is described in the paper "Model-Based Sampling and Inference," available on the EIA web site at http://www.eia.doe.gov/cneaf/electricity/page/forms.html. Additional references can be found on the InterStat website at http://www.interstat.statjournals.net/. For instance, see "Practical Methods for Electric Power Survey Data," in InterStat, July 2002, article # 1. Additionally, the basis for the current methodology, which involves a 'borrowing of strength' technique for small domains, is found in "Using Prediction-Oriented Software for Survey Estimation," in InterStat, August 1999, article # 1. Also highly relevant are "The Classical Ratio Estimator," in InterStat, October 2005, article # 4 and "Cutoff Sampling and Inference," in InterStat, April 2007, article # 6.

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 EIA 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-412, "Annual Electric Industry Financial Report;" [Terminated]
- Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;"
- Form EIA-767, "Steam-Electric Plant Operation and Design Report;" [Suspended]
- Form EIA-860, "Annual Electric Generator Report;"
- Form EIA-861, "Annual Electric Power Industry Report;"
- Form EIA-906, "Power Plant Report;" and
- Form EIA-920, "Combined Heat and Power Plant Report."

A brief description of each of these forms can be found on the EIA website on the Internet with the following URL: http://www.eia.doe.gov/cneaf/electricity/page/forms.html.

Each of these forms 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;"
- Federal Energy Regulatory Commission Form 423, "Cost and Quality of Fuels for Electric Plants;"
- Rural Utility Services Form 7, "Financial and Statistical Report;" and
- Rural Utility Services 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-759, "Monthly Power Plant Report," Form EIA-860A, "Annual Electric

Generator Report–Utility," Form EIA-860B, "Annual Electric Generator Report–Nonutility," and 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[1] and are not reported to DOE.

Form EIA-411

The Form EIA-411 is filed as a voluntary report. 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 8 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. This form is 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 Mid-Continent Area Power Pool (MAPP) to Midwest Reliability Organization (MRO) and the Western Systems Coordinating Council (WSCC) to Western Energy 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. The State of Alaska is not contiguous with the other continental States and has no electrical interconnections.

At the close of calendar year 2005, the follow reliability regional councils were dissolved: East Central Area Reliability Coordinating 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. Reliability Councils that are unchanged include: Electric Reliability Council of Texas (ERCOT), Northeast Power Coordinating Council (NPCC), and the Western Energy Coordinating Council (WECC). The historical time series have not been adjusted to account for individual membership shifts.

The new NERC Regional Council names are as follows:

- Electric Reliability Council of Texas (ERCOT),
- Florida Reliability Coordinating Council (FRCC),
- Midwest Reliability Organization (MRO),
- Northeast Power Coordinating Council (NPCC),
- Reliability*First* Corporation (RFC),
- Southeastern Electric Reliability Council (SERC),
- Southwest Power Pool (SPP), and

[1] 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 2006, California - ISO reported electric purchases of 1,048,610 MWh and sales of 498, 268 MWh.

- Western Energy Coordinating Council (WECC).

Concept of Demand and Supply within the EIA-411: Historically, the voluntarily filed 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]

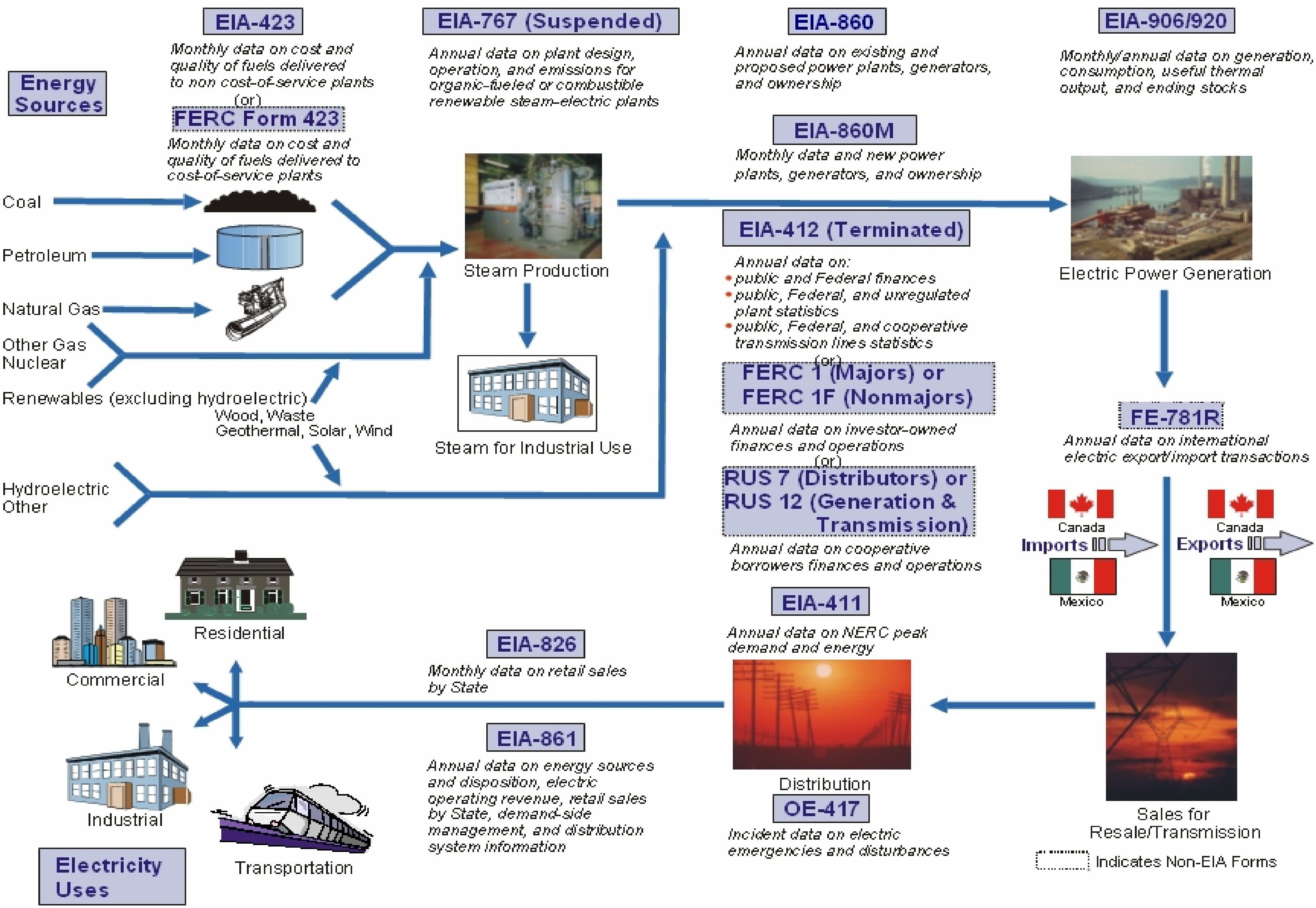
The Form EIA-412 was a restricted-universe census (no companies that fell below a pre-determined threshold were required to file) used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Those publicly owned electric utilities 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 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



The 1993-1997 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.

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

The Form EIA-423, “Monthly Cost and Quality of Fuels for Electric Plants Report,” collects information from selected electric generating plants in the United States. The data collected on this survey include the cost and quality of fossil fuels delivered to nonutility plants to produce electricity. These plants include 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. The Form EIA-423 survey respondents are required to submit their data by the 45th calendar day following the close of the month.

Instrument and Design History. 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 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.

Formulas and Methodologies. Data for the Form EIA-423 are collected at the plant level. These data 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, ∑, 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:

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

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

A_i = average heat content for receipts at facility i;

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

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:

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

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:

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

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.

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

The Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," is administered by FERC. The data are downloaded from the Commission's website into an EIA database. The Form is due to FERC no later than 45 days after the end of the report month and is filed by approximately 600 regulated plants. To meet the criteria for filing, a plant must have 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 is reported. Fuel received for use in gas-turbine or internal-combustion units that is not associated with a combined-cycle operation is not reported.

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.

Data Processing and Data System Editing. The FERC posts a monthly file on their website: http://www.ferc.gov/docs-filing/eforms.asp#423. The EIA downloads the file and reviews the data for accuracy. Edit checks of the data are performed through computer programs. These 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 other data elements in the file.

Estimation for FERC Form 423 Data. In order to address FERC Form 423 fuel receipts data that were determined to either be out of range (+/- 20 percent) or missing due to non-response beginning in 2003, a procedure was utilized to estimate fuel receipts for the affected plants on a monthly basis. For missing or out-of-range natural gas receipts, the monthly consumption value from the Form EIA-906, "Power Plant Report," was used as a proxy for the monthly receipts. For missing or out-of-range coal and petroleum receipts, the estimated monthly fuel receipts were calculated using the Form EIA-906 data (where receipts were estimated to be equal to the monthly fuel consumption plus the difference between ending and beginning fuel stocks).

For each non-respondent, the associated fuel quality and cost information for each fuel was estimated using the State weighted average for the electric power industry for the month (FERC Form 423 and Form EIA-423). In the event that no values were available at the State level, national averages for the electric power industry for the month were used.

Beginning in 2005, the procedure used the State or national averages for fuel quality and cost information only in the event of non-response. For out of range receipts, the reported fuel quality and cost information for each facility was retained. Prior to 2005, the State or national average value was used in the case of out of range receipts in addition to non-response.

Formulas and Methodologies. Data for the FERC Form 423 are collected at the plant level. These data are then used in the same formulas shown under the "Formulas and Methodologies" section for 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 are compiled by EIA from data collected by the Federal Energy Regulatory Commission (FERC) on the FERC Form 423. These data are collected by FERC for regulatory rather than statistical and publication purposes. EIA does 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.

Form EIA-767

Due to budgetary reasons, the collection of Form EIA-767 data was suspended for calendar year 2006. Most of the form EIA-767 information is planned to be collected for calendar year 2007 on another form. 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 submit 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 given the name 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. <u>Collection of data via the form was suspended for the 2006 data year</u>.

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). 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. 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.

Estimation of EIA-860 Data. No imputation was performed for the 2006 data. All respondents in the frame submitted Form EIA-860 for 2006 data.

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.

In the *Electric Power Annual 2006*, capacity by producer type is 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 2006 capacity 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 January 1 of the reporting 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 the current data year. These summaries are based on data collected from new questions added to the 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 are noted as revised data.

Sensitive Data (Formerly Identified as Data Confidentiality). The plant latitude and longitude and 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 are 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 EIA's 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 to estimate electricity transportation consumption by EIA. 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 2006, 67 respondents reported transportation data in 27 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. EIA 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 adds 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 2006 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 2006, their data were assumed to be the amount imputed during the year using the EIA-826 sample form collection and imputation process. No special imputation process was implemented to account for differences in the EIA-861 and EIA-826 submitted forms.

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. EIA has concluded that the retail sales data reported by delivery utilities are more reliable than data reported by power marketers and ESPs.

The reporting methodology change uses sales volumes and customer counts reported by distribution utilities, and adds 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.

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 1998-2006 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

The Form EIA-906 is used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content, from electric utilities and nonutilities. Data are collected monthly from a model-based sample of approximately 1,700 utility and nonutility electric power plants. The form is 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 monthly data are due by the last day of the month following the end of the reporting month and the annual data are due by March 1.

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.

Estimation of EIA-906 Data. Of the approximately 4,400 plants in the Form EIA-906 frame for 2006, some estimation was performed for 2 plants. These plants account for 0.001 percent of national total generation (i.e., the total for plants reporting on either the EIA-906 or EIA-920 surveys) and 0.001 percent of the national total fuel consumption.

Finalization of the Monthly Data and Annual Totals. The EIA-906 data are finalized once data has been collected from the annual respondents who are not part of the monthly sample. The data from annual responses that pass edit checks are proportioned to the months (by State, fuel and sector) using the ratio of the monthly data actually collected to the sum of that monthly data. In the case of annual facilities that are non-respondents, or whose data fail edit checks and have data problems that cannot be resolved, generation and consumption are imputed monthly. The sum of the revised monthly data is the final annual totals for each State, fuel and sector combination.

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[1] beginning with 2001 data by the following methodology:

The reported tonnage of MSW is reported on the Form EIA-906, "Power Plant Report," and the Form EIA-920, "Combined Heat and Power Plant Report." 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).

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.

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." Data for these types of plants are collected on the Form EIA-906. No information on the production of UTO or fuel consumption for UTO is 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

The Form EIA-920, "Combined Heat and Power Plant Report" is used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content of combined heat and power (CHP) plants. Data are collected monthly from a sample of 319

[1] 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.

[2] Sources: 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; 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; Utah State University Recycling Center Frequently Asked Questions. Published at http://www.usu.edu/recycle/faq.htm. Accessed December 2006.

plants. The form is also used to collect these statistics from 570 combined heat and power plants on an annual basis. The monthly data are due by the last day of the month following the end of the reporting month and the annual data are due by March 30.

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. (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.

Estimation of EIA-920 Data.

Routine Estimation of Useful Thermal Output and Fuel for Useful Thermal Output

Useful thermal output (UTO) is the thermal energy, usually in the form of steam, produced by a CHP system for use in any commercial or industrial application other than electric power generation. As discussed above, UTO was previously collected on the Form EIA-906. However, on the new EIA-920 Form, UTO is no longer collected. The Form EIA-920 asks for total fuel consumption and fuel consumption for electricity production. Fuel consumption to produce available, or gross, UTO can then be estimated by a subtraction process (Fuel consumption for UTO = Total consumption – Consumption for generation, expressed in thermal units.) The recovered, or net, UTO itself is then estimated by multiplying fuel consumption for available, or gross, UTO by an assumed thermal conversion factor of 80 percent.

Imputation for Annual Respondents and Non-Respondents

Monthly fuel consumption data are imputed for non-respondents, including out-of-sample annual respondents until their data are collected after the end of the calendar year. As discussed elsewhere in these Technical Notes, generation is imputed using statistical techniques. Given imputed generation, consumption for generation is estimated by multiplying generation by the plant's prior year heat rate. Recovered UTO is estimated by:

- Converting the plant's generation to a heat equivalent, computed as 3,412 Btus per kilowatthour.
- Dividing the heat equivalent of generation by the plant's historical power-to-steam ratio. (The power-to-steam ratio is the ratio of the heat equivalent of the plant's generation divided by MMBtus of recovered UTO produced by the plant.)

Fuel for available UTO is then computed by dividing recovered UTO by the assumed estimated thermal conversion factor of 80 percent.

Reallocation of Fuel for Plants with Out-of-Range Reported Data

In addition to the imputation of missing values, consumption for generation is estimated for respondents reporting an unusually high allocation of total fuel to power production. Specifically, with the change in survey instruments in January 2004 from the Form EIA-906 to the Form EIA-920, a significant number of CHP respondents began reporting a much larger allocation of fuel to power production – and therefore, by implication, a much smaller allocation of fuel to UTO production – than in 2003 and earlier years. Increased allocation of fuel to generation implies that these facilities are less efficient producers of electricity than they previously appeared and have an overall thermal efficiency lower than expected for CHP plants. In some cases plants allocated 100 percent of their fuel consumed to power generation.

EIA made two types of adjustments to the fuel consumption of CHP plants reporting an unusually high allocation of fuel to generation:

- For steam electric plants reporting either a 100 percent allocation or a very large allocation of fuel to generation, the allocation of fuel between generation and UTO was re-computed to be consistent with the plant's historical power to steam ratio or with the industry average power to steam ratio if the plant's historical value also seemed questionable or missing.

- The same type of adjustment was made to fuel consumption for the combustion turbine part of combined cycle CHP plants, but only if the plant reported allocating all of its fuel to generation.

The adjustments, which were designed to modify reported values for the least ambiguous instances of possible over-allocation of fuel to generation, are provisional pending further research.

Portion of Fuel Consumption and Generation Data that are Estimated for the Form EIA-920

For 2006 data, the allocation of fuel between generation and production of UTO was adjusted for about 220 plants in some or all months of the year. These plants accounted for 28 percent of all generation and 34 percent of all fuel consumption data collected by the EIA-920 survey. They accounted for 1 percent of total national generation and 2.9 percent of total national fuel consumption in 2006. In 2006, there were zero non-respondents on the Form EIA-920.

Finalization of the Monthly Data and Annual Totals. The EIA-920 data are finalized once data have been collected from the annual respondents who are not part of the monthly sample. The data from annual responses that pass edit checks are proportioned to the months (by State, fuel, and sector) using the ratio of the monthly data actually collected to the sum of that monthly data. In the case of annual facilities that are non-respondents, or whose data fails edit checks and have data problems that cannot be resolved, generation and consumption is imputed monthly. The sum of the revised monthly data is the final annual totals for each State, fuel, and sector combination.

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." Data for these types of plants are collected on the Form EIA-906. No information on the production of UTO or fuel consumption for UTO is 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 is fuel stocks at the end of the reporting period.

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO_2) from electric generating plants for 1989 through 2006, as well as the estimated emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from electric generating plants for 2001 through 2006. 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 Forms EIA-906 and EIA-920. 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.[3] 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 historic EIA-767 survey. A special case for removal of SO_2 is the fluidized bed boiler, in which the sulfur removal

[3] 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/glossary_main_page.htm. 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.

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.

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-920 (data for combined heat and power plants) and EIA-906 (all other power plants). 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 and a factor that accounts for incomplete combustion. The incomplete combustion factor is 0.995 for natural gas and 0.99 for all other fuels.

The estimation procedure calculates uncontrolled CO_2 emissions. CO_2 control technologies are currently in the early stages of research and there are no 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 historic Form EIA-767. The EIA-767 survey was limited to plants with boilers fired by combustible fuels[4] 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 historic EIA-767 survey.

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

- For steam electric plants that reported on the historic Form EIA-767, 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. 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 historic Form EIA-767 survey, 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-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 on 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-423 and the FERC Form 423 data, 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 historic Form EIA-767. For these cases, the plant is assumed to have a dry-bottom, non-cyclone boiler using a firing method that falls

[4] 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 historic Form EIA-767.

into the "All Other" category shown on Table A1.[5]

  - For the plants that did not report on the historic Form EIA-767, 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.

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

The nonutility industry consists of all manufacturing, agricultural, forestry, transportation, finance, service, and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual. 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
2121 Coal mining
211 Oil and gas extraction
2122 Metal mining
2123 Mining and quarrying of nonmetallic minerals except fuels

Construction
23

Manufacturing
311 Food and kindred products
3122 Tobacco products

[5] 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 historic Form EIA-767, see the form instructions, page xi, at http://www.eia.doe.gov/cneaf/electricity/forms/eia767/eia767instr.pdf.

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)
325188 Industrial Inorganic Chemicals
325211 Plastics materials and resins
32512 Industrial organic chemicals
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
92

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: 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 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: 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; 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 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: 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: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design 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: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Table A6. Average Heat Rates by Prime Mover and Energy Source, 2006
(Btu per kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas	Nuclear
Steam Turbine	10,164	10,424	10,490	10,434
Gas Turbine	--	13,155	11,664	--
Internal Combustion	--	10,179	9,947	--
Combined Cycle	W	11,015	7,502	--

W = Withheld to avoid disclosure of individual company data.
Note: Heat rate is reported at full load conditions for electric utilities and independent power producers. See Glossary reference for definitions. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

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