Electric Power Annual 2004

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Electric Power Annual 2004

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Contacts

Questions regarding this report may be directed to:
Energy Information Administration, EI-53
Electric Power Division
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-0650

Questions of a general nature should be directed to:
Robert Schnapp (202/287-1787)
Director, Electric Power Division
e-mail: robert.schnapp@eia.doe.gov

Contributions to this report were provided by the following employees of the Electric Power Division (fax number 202/287-1946):

Publication Coordinator:
John W. Makens (202/287-1749)
e-mail: john.makens@eia.doe.gov;

Team Leader Coordinators:
Stan Kaplan (202/287-1803)
Generation and Capacity Team
e-mail: stan.kaplan@eia.doe.gov;

Thomas Schmitz (202/287-1919)
Annual Team
e-mail: thomas.schmitz@eia.doe.gov;

Dean Fennell (202/287-1744)
Monthly Team
e-mail: dean.fennell@eia.doe.gov;

Generation
Melvin E. Johnson (202/287-1754)
e-mail: melvin.johnson@eia.doe.gov;
Channele Wirman (202/287-1928)
e-mail: channele.wirman@eia.doe.gov;
Orhan Yildiz (202/287-1586)
e-mail: orhan.yildiz@eia.doe.gov;

Capacity
Kenneth McClevey (202/287-1732)
e-mail: kenneth.mcclevey@eia.doe.gov;
Glenn McGrath (202/287-1745)
e-mail: glenn.mcgrath@eia.doe.gov;

Demand, Capacity Resources, and Capacity Margins
John Makens (202/287-1749)
e-mail: john.makens@eia.doe.gov;

Fuel
Melvin E. Johnson (202/287-1754)
e-mail: melvin.johnson@eia.doe.gov;
Stephen R. Scott (202/287-1737)
e-mail: stephen.scott@eia.doe.gov;
Rebecca A. McNerney (202/287-1913)
e-mail: rebecca.mcnerney@eia.doe.gov;
Channele Wirman (202/287-1928)
e-mail: channele.wirman@eia.doe.gov;
Orhan Yildiz (202/287-1586)
e-mail: orhan.yildiz@eia.doe.gov;

Emissions
Natalie Ko (202/287-1957)
e-mail: natalie.ko@eia.doe.gov;
Kevin G. Lillis (202/287-1757)
e-mail: kevin.lillis@eia.doe.gov;

Trade
Rodney Dunn (202/287-1676)
e-mail: rodney.dunn@eia.doe.gov;
Thomas J. Leckey (202/287-1840)
e-mail: thomas.leckey@eia.doe.gov;

Retail Customers, Sales, and Revenue
Rodney Dunn (202/287-1676)
e-mail: rodney.dunn@eia.doe.gov;
Thomas J. Leckey (202/287-1840)
e-mail: thomas.leckey@eia.doe.gov;

Revenue and Expense Statistics
Karen McDaniel (202/287-1799)
e-mail: karen.mcdaniel@eia.doe.gov;
Thomas J. Leckey (202/287-1840)
e-mail: thomas.leckey@eia.doe.gov;

Demand-Side Management
Rodney Dunn (202/287-1676)
e-mail: rodney.dunn@eia.doe.gov;
Thomas J. Leckey (202/287-1840)
e-mail: thomas.leckey@eia.doe.gov.

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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 202/287-1787, or Internet 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 2004 presents a summary of electric power industry statistics at the national level. The objective of the publication is to provide 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.

In the private sector, the majority of the users of the *Electric Power Annual* are researchers, analysts, and individuals with policymaking and decision-making responsibilities in electricity companies or other energy concerns. Other users include financial and investment institutions, economic development organizations, special interest groups, lobbyists, electric power associations, and the news media.

In the public sector, users include the U.S. Congress, Federal government agencies, State governments and public service commissions, and local governments. Data in this report can be used in analytic studies to evaluate new legislation and are used by analysts, researchers, statisticians, and other professionals with regulatory, policy, and program responsibilities for Federal, State, and local governments.

The *Electric Power Annual* presents an overview of the electric power industry in the United States and a summary of the key statistics for the reporting year. The chapters present information and data in each specific area: 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 five surveys performed by other government organizations and seven surveys completed annually or monthly by electric utilities and other electric power producers and submitted to the EIA. The EIA forms are described in detail in the "Technical Notes."

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Overview

The electric power industry continued growing in 2004. Electricity generation and sales rose for the third straight year to record levels, growing by 2.3 percent and 1.7 percent, respectively, over the 2003 levels, as the U.S. economy continued to grow. Net additions to summer generating capacity also grew for the sixth year in a row, also setting a record, with most of the new capacity coming from natural gas units. While retail electricity sales grew, the average retail price of electricity also rose to a record level, growing 2.7 percent in 2004. Contributing to this were the record prices of coal and natural gas delivered to electric generating plants. Energy service providers, who operate in the 19 States that allow retail electricity competition, accounted for 8 percent of national retail electricity sales, up from 0.6 percent in 1999. They also provided 18 percent of all of the electricity sold in those 19 States.

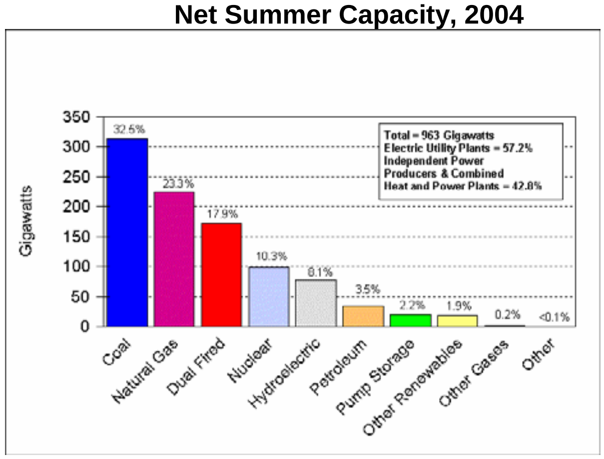
Capacity

For calendar year 2004, total net summer generating capacity in the United States was 963 gigawatts, an increase of 1.5 percent from 2003. The industry added 21 gigawatts of net new capacity (new generators) in 2004, which is less than one-half of the capacity added in each of the previous two years. Ninety-four percent of the new unit capacity was natural gas-fired or dual-fired (capable of burning either natural gas or petroleum).

Coal-fired capacity accounted for nearly 33 percent of the U.S. electric generating capacity in 2004. This share represents a slight decline from 2003 due to the fact that capacity additions over the past year have been primarily natural gas-fired. In addition, some older, inefficient coal-fired generators have been retired from service or re-powered into more efficient natural gas-fired combined cycle plants. In 2004, 553 megawatts of new coal-fired generators started commercial operation, while approximately 543 megawatts of coal-fired capacity was retired from service. Natural gas and dual-fired capacity together accounted for 41 percent of the total generating capacity. Over 15,300 megawatts of new natural gas-fired capacity and 4,776 megawatts of new dual-fired capacity were added during 2004, while 5,974 megawatts natural gas and dual-fired were retired. Nuclear accounted for a 10-percent share of capacity, while the combination of conventional hydroelectric and other renewables (wood products, solar, wind, etc.) also accounted for 10 percent of the total. (Figure ES1).

For the 2005 through 2009 planning period, respondents to Form EIA-860 reported 94 gigawatts (nameplate capacity) of new generators are scheduled to start commercial operation. While natural gas-fired and dual-fired generators currently account for about 80 percent of the planned capacity additions, that number may decrease as other methods of generation come back into favor. For example, with 13 gigawatts of planned new coal-fired generators, the plans reflect some prospects for the re-emergence of significant new coal-fired capacity that is expected to employ clean coal technology. In addition, volatility in natural gas prices and supplies could also bring into question some planned gas-fired generation projects. Overall, the 94 gigawatts of capacity that will reportedly be added over the next 5 years show a significant decrease from the additions (227 gigawatts) that actually occurred over the past 5 years.

Figure ES 1. U.S. Electric Power Industry Net Summer Capacity, 2004



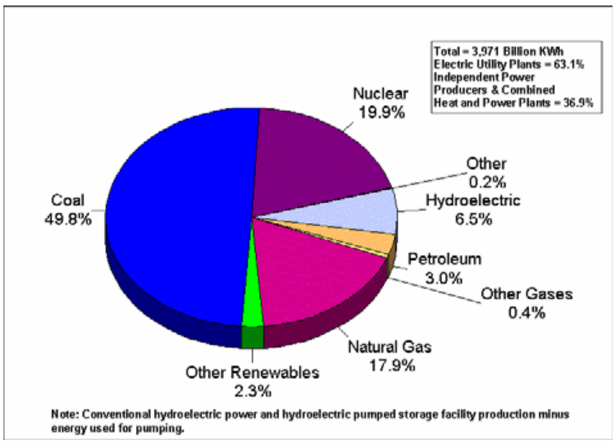
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Generation

In 2004, net generation of electricity rose slightly to 3,971 billion kilowatthours. This represents a 2.3 percent growth in electricity generation over the 2003 level; however, it is above the average annual growth rate of 2.0 percent between 1993 and 2004 due mainly to a return to more normal summer temperatures in 2004, compared to the below-normal 2003 summer temperatures experienced in 2003. Regulated electric utilities' share of total generation continued to decline (63.1 percent in 2004 vs. 63.4 percent in 2003) as Independent Power Producers' (IPPs) share increased (28.2 percent vs. 27.4 percent in 2003). About 49.8 of all generation in 2004 came from coal-fired power plants (Figure ES2). This is a 1.0 percentage point reduction from 2003, as the share accounted for by natural gas plants rose by 1.2 percentage points, due to the additional natural gas capacity that came on line in 2004.

In 2004, the physical consumption of coal volume for electric power generation increased by 1.2 percent from 2003. However, the average Btu per ton continues to drop slightly each year due to increased consumption of lower-Btu subbituminous coal, and decreased consumption of bituminous coal. The actual volume of consumption of natural gas increased 8.8 percent and petroleum consumption increased 1.4 percent. New capacity contributed to the increased usage of these two fuels for electric power generation.

Figure ES 2. U.S. Electric Power Industry Net Generation, 2004



Source: Energy Information Administration, Form EIA-906, "Power Plant Report."

Fuel

The average cost for two of the three major fossil fuels used for electricity generation (natural gas and coal) increased between 2003 and 2004, while the average cost of petroleum declined slightly. In addition, the average combined cost of the three fossil fuels used for electricity generation continued to trend upward.

The average cost of natural gas to electricity generators increased from the previous record high of $5.39 per million Btu (MMBtu) established in 2003 to a new record level of $5.96 per MMBtu in 2004 (Figure ES 3). While not as significant as the 51.5 percent increase in cost between 2002 and 2003, natural gas still experienced a double-digit growth increase of 10.5 percent from 2003 to 2004. Strong demand for natural gas, due in part to high demands for heating and high petroleum prices, as well as natural gas production disruptions in the Gulf of Mexico caused by Hurricane Ivan, contributed to the increase in the price of natural gas over the course of the year. The cost of natural gas for electricity generation in 2004 was 67.4 percent higher than in 2002.

The average cost of coal also increased for the year, from $1.28 per MMBtu in 2003 to $1.36 per MMBtu in 2004. Coal prices have been trending upward since 2000, and the 2004 cost represents the highest cost for coal since 1993. From 2003 to 2004, coal costs increased by 6.2 percent. Coal prices increased in response to the continued increase in natural gas prices and the historically high level of petroleum prices in the electric power sector. Coal costs in 2004 were 8.5 percent higher than in 2002.

For the year, average petroleum costs decreased slightly, from a level of $4.34 per MMBtu in 2003 to $4.29 per MMBtu in 2004. On a percentage basis, the cost of petroleum decreased by 1.0 percent from 2003 to 2004; however, over the two year period from 2002 to 2004, petroleum costs increased by 28.5 percent. Overall, U.S. petroleum demand in 2004 was strong. While declining only marginally from 2003 to 2004, petroleum prices remained at historically high levels influenced by the increases in use by the transportation and industrial sectors as well as the demand for petroleum products for the production of electricity.

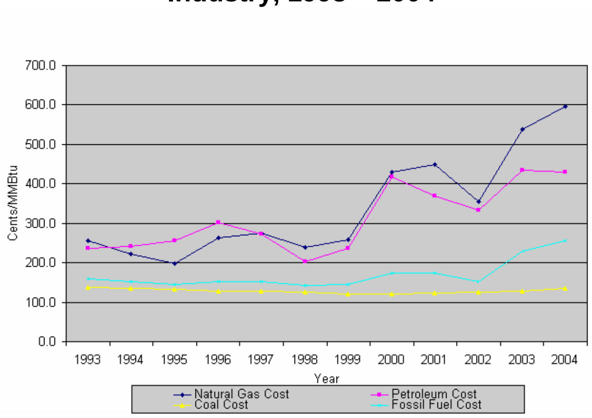
The average cost for all fossil fuels used for electricity generation (coal, petroleum and natural gas combined) in 2004 was $2.57 per MMBtu (Table 4.5) as compared to $2.28 per MMBtu in 2003. This reflects an increase of 12.5 percent from 2003 to 2004. The 2004 average combined cost for all fossil fuels was 69.4 percent higher than in 2002.

Emissions

The carbon dioxide, sulfur dioxide and nitrogen oxides emissions estimates for electricity reflect fuel consumed for electric power generation and, for combined heat and power plants, for the production of useful thermal output. In addition to the new 2004 estimates, the 2003 estimates have been revised for all three types of emissions.

Estimated carbon dioxide emissions by U.S. electric generators increased by 1.2 percent from 2003 to 2004 (from 2,438 million metric tons to 2,467 million metric tons). The increase reflects greater use of coal, petroleum products and natural gas. In contrast, estimated emissions of sulfur dioxide and nitrogen oxides declined between 2003 and 2004. Sulfur dioxide emissions dropped by 3.2 percent (from 10.6 to 10.3 million metric tons) and emissions of nitrogen oxides declined by 8.7 percent (from 4.3 to 4.0 million metric tons). The declines in emissions, even as use of fossil fuels increased, reflects the impact of federal and State pollution control regulations on power plant operations, including requiring the installation of new pollution control equipment. Another factor was the increased use of subbituminous coal. Because of its typically low sulfur content and combustion temperature, subbituminous coal generally emits less sulfur dioxide and nitrogen oxides when burned than other coals.

Figure ES 3. Fuel Costs for the Electric Power Industry, 1993 – 2004



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."

Trade

Much of the electricity generation consumed by the end-user is actually bought and sold among electric utilities. One of the primary reasons for this is that the participants in the electric power industry search for the best value for their buying and selling transactions and also to participate in transactions to mitigate risk. The utilities do this by either the use of long-term contracts and/or by the use of other economic short-term (spot market) contracts.

In international electricity trade, Canada is the United States' dominant partner. Mexico's participation is limited to a small amount of transactions that cross the border with the States of California, Arizona, and Texas. Since Canada was undergoing drought conditions in 2003 and for part of 2004, the hydroelectric-producing provinces enforced conservation measures and purchased more electricity from the United States (22.5 billion kilowatthours in 2004 versus 23.6 billion kilowatthours in 2003). Because of the overall milder summer weather in Canada during 2004 and a delay of colder weather in the Pacific Northwest, more electrical energy was available for sale to the United States. Therefore, U.S. imports grew to 34.2 billion kilowatthours.

International trade provides another source of electrical energy in which the economic benefits are gained by acquiring lower priced surplus power (mostly hydroelectric generation caused by heavy seasonal river flows). Other opportunities international trade offers include the ability to purchase lower priced off-peak power at the time of the U.S. utilities peaking period, and mitigating risk by acquiring emergency support to replace generating capability lost from outages. In addition, indirect benefits are gained in both Canada and the United States. The reliability of the different power grids are improved because of the reinforcement coming from strong transmission ties.

Revenue and Expense Statistics

In 2004, electric utility operating revenues (sales to ultimate customers, sales for resale, and other electric income) were $240 billion for major investor-owned utilities, a 6 percent increase for the investor-owned sector from 2003. In 2004, operating expenses were $207 billion, a 5 percent increase from 2003 for investor-owned utilities. Net income for the investor-owned utilities grew strongly, about fifteen percent, as non-production expenses increased only negligibly. Tax expenses among investor-owned utilities declined significantly for the second straight year, falling from 16 percent of electric utility operating expenses in 2002 to 12 percent in 2004.

For major cooperative borrowers, electric utility operating revenues were $31 billion, a 5 percent increase for the cooperatives from 2003. In 2004, operating expenses were $28 billion, a 6 percent increase for cooperatives. Net operating income differed significantly between the major investor-owned class and the major cooperative borrowers. The net operating income for the major investor–owned class rose approximately 15 percent while the major cooperative borrower-owned class fell about 2 percent.

Expense increases for the electric power industry, were driven by higher fossil fuel prices and passed on to consumers as higher end-use prices for electricity. Normal sales growth and higher end-use prices contributed to the increase in revenue. Cooperatives passed these higher prices on more readily to their members than investor-owned utilities did to their end-use customers, but despite the higher prices, net income among the cooperative borrowers decreased from 2003 to 2004.

Data for the publicly-owned utilities are not available for 2004 so no comparison against 2003 data can be made. Data for publicly-owned utilities was not collected because EIA suspended its Form EIA-412 survey in 2004.

Retail Customers, Sales, and Revenues

Retail sales of electricity increased to 3,548 billion kilowatthours in 2004, a 1.7 percent increase from 2003 and a pace close to the historical growth rate. Revenue, however, increased to over $270 billion in 2004, a 4.5 percent increase from 2003 and the second straight year of strong growth. All customer classes except transportation faced higher average retail prices in 2004, as the national average price across all sectors was 7.62 cents per kilowatthour, up from 7.42 cents in 2003.

The average retail price in the residential sector increased to 8.97 cents per kilowatthour, a 3.1 percent increase from 2003. In the commercial and industrial sectors, average price increases were 2.0 percent and 2.9 percent, respectively. Higher fossil fuel prices to electricity generators led to higher wholesale power costs. Average end-use prices rose dramatically in States where natural gas fuels significant portions of baseload generating capacity—Texas, Mississippi, Louisiana, and Florida.

Sales to the residential sector in 2004 were 1,294 billion kilowatthours, an increase from 2003 of 1.6 percent. Commercial sales in 2004 were 1,229 billion kilowatthours, an increase of 2.7 percent. Industrial sales in 2004 were 1,019 billion kilowatthours, an increase of 0.7 percent. The residential sector accounted for 36 percent of the volume in 2004, and the commercial sector for 35 percent. In 2004, the industrial sector accounted for 29 percent of the sales volume. Ten years ago, the three major end-use sectors accounted for roughly equal shares of the sales volume, but since then, the commercial sector has grown at an average annual rate of 4.0 percent and industrial sales have increased only negligibly. The transportation sector, which includes electricity delivered to and consumed by local, regional, and metropolitan mass transportation systems, accounted for sales of 7 billion kilowatthours, a fraction of the national total, virtually unchanged from 2003.

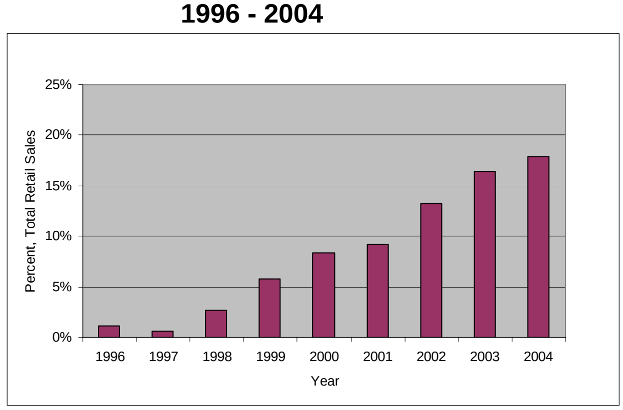
Sales from energy service providers have been increasing significantly since 1997.[1] (Figure ES-4).

In 2004, ESPs accounted for 8 percent of the total U.S. sales, and 18 percent of total sales within the 19 States that allow energy only providers. California led all States in 2004 with ESP sales of 76 billion kilowatthours, or 30 percent of that State's total sales, and 28 percent of total ESP sales nationally. ESPs reported strong sales growth in the commercial and industrial sectors, indicating some loss of market share by native load serving entities. Industrial and commercial end use customers of ESPs generally obtained lower average prices than customers choosing to remain with traditional bundled service in the deregulated States.

Demand-Side Management

In 2004, electricity providers reported total peak-load reductions of 23,532 megawatts resulting from demand-side management (DSM), a slight increase from that reported in 2003. Reported DSM costs increased to $1.6 billion, a 20 percent increase from costs reported in 2003. 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 vary directly by year. Nonetheless, nominal DSM expenditures have declined 43 percent over the last ten years, in part due to elimination of some DSM requirements when States have moved to more competitive markets.

Figure ES 4. Market Share of Energy Only Providers in Deregulated States, 1996 - 2004



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

[1] Energy service providers are power marketers or other electricity vendors who provide an unbundled service and bill for only the energy component of the electricity consumed by the end-use customer.

Table ES. Summary Statistics for the United States, 1993 through 2004

Description	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Net Generation (thousand megawatthours)												
Coal[1]	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	1,690,694	1,690,070
Petroleum[2]	120,646	119,406	94,567	124,880	111,221	118,061	128,800	92,555	81,411	74,554	105,901	112,788
Natural Gas	708,979	649,908	691,006	639,129	601,038	556,396	531,257	479,399	455,056	496,058	460,219	414,927
Other Gases[3]	16,766	15,600	11,463	9,039	13,955	14,126	13,492	13,351	14,356	13,870	13,319	12,956
Nuclear	788,528	763,733	780,064	768,826	753,893	728,254	673,702	628,644	674,729	673,402	640,440	610,291
Hydroelectric Conventional[4]	268,417	275,806	264,329	216,961	275,573	319,536	323,336	356,453	347,162	310,833	260,126	280,494
Other Renewables[5]	90,408	87,410	86,922	77,985	80,906	79,423	77,088	77,183	75,796	73,965	76,535	76,213
Pumped Storage[6]	-8,488	-8,535	-8,743	-8,823	-5,539	-6,097	-4,467	-4,040	-3,088	-2,725	-3,378	-4,036
Other[7]	6,679	6,121	5,714	4,690	4,794	4,024	3,571	3,612	3,571	4,104	3,667	3,487
All Energy Sources	**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**	**3,247,522**	**3,197,191**
Net Summer Generating Capacity (megawatts)												
Coal[1]	313,020	313,019	315,350	314,230	315,114	315,496	315,786	313,624	313,382	311,386	311,415	310,148
Petroleum Only[2]	33,702	36,429	38,213	39,714	35,890	35,587	40,399	43,202	43,585	43,708	42,695	44,019
Natural Gas Only	224,257	208,447	171,661	125,798	95,705	73,562	75,772	76,348	74,498	75,438	70,685	65,523
Dual Fired	172,170	171,295	162,289	153,482	149,833	146,039	130,399	129,384	128,570	121,958	123,110	120,157
Other Gases[3]	2,296	1,994	2,008	1,670	2,342	1,909	1,520	1,525	1,664	1,661	2,093	1,931
Nuclear	99,628	99,209	98,657	98,159	97,860	97,411	97,070	99,716	100,784	99,515	99,148	99,041
Hydroelectric Conventional[4]	77,641	78,694	79,354	79,484	79,359	79,393	79,151	79,415	76,437	78,562	78,041	77,410
Other Renewables[5]	18,763	18,199	16,755	16,180	15,572	15,942	15,444	15,351	15,309	15,300	15,021	14,656
Pumped Storage[8]	20,764	20,522	20,373	19,096	19,522	19,565	19,518	19,310	21,110	21,387	21,208	21,146
Other[7]	700	638	641	440	523	1,023	810	774	550	550	550	550
All Energy Sources	**962,942**	**948,446**	**905,301**	**848,254**	**811,719**	**785,927**	**775,868**	**778,649**	**775,890**	**769,463**	**763,967**	**754,582**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	692,908	696,752	696,376	674,833	680,941	653,857	638,086	618,389	602,438	589,860	578,640	565,041
Capacity Resources (megawatts)	875,870	856,131	833,380	788,990	808,054	765,744	744,670	737,855	730,376	727,481	711,583	705,360
Capacity Margins (percent)	20.9	18.6	16.4	14.5	15.7	14.6	14.3	16.2	17.5	18.9	18.7	19.9
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	1,026,011	1,014,058	987,583	972,691	994,933	949,802	946,295	931,949	907,209	860,594	848,796	842,153
Petroleum (thousand barrels)[2]	209,496	206,653	168,597	216,672	195,228	207,871	222,640	159,715	144,626	132,578	183,618	192,462
Natural Gas (millions of cubic feet)	6,111,307	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	4,367,148	3,928,653
Other Gases (millions of btu)[3]	186,963	156,306	131,230	97,308	125,971	126,387	124,988	119,412	158,560	132,520	136,381	136,230
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	18,786	17,720	17,561	18,944	20,466	20,373	20,320	21,005	20,806	20,418	20,609	19,750
Petroleum (thousand barrels)[2]	19,860	17,939	14,811	18,268	22,266	26,822	28,845	28,802	27,873	25,562	27,929	26,394
Natural Gas (millions of cubic feet)	614,760	721,267	860,019	898,286	985,263	982,958	949,106	868,569	865,774	834,382	784,015	733,584
Other Gases (millions of btu)[3]	167,272	137,838	146,882	166,161	230,082	223,713	208,828	187,680	187,290	180,895	179,595	177,554
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	1,044,798	1,031,778	1,005,144	991,635	1,015,398	970,175	966,615	952,955	928,015	881,012	869,405	861,904
Petroleum (thousand barrels)[2]	229,356	224,593	183,408	234,940	217,494	234,694	251,486	188,517	172,499	158,140	211,547	218,855
Natural Gas (millions of cubic feet)	6,726,067	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	5,151,163	4,662,236
Other Gases (millions of btu)[3]	354,236	294,143	278,111	263,469	356,053	350,100	333,816	307,092	345,850	313,415	315,976	313,784
Stocks at Electric Power Sector (year end)												
Coal (thousand tons)[9]	106,669	121,567	141,714	138,496	102,296	141,604	120,501	98,826	114,623	126,304	126,897	111,341
Petroleum (thousand barrels)[10]	51,434	53,170	52,490	57,031	40,932	54,109	56,591	51,138	48,146	50,821	63,333	62,890
Receipts of Fuel at Electricity Generators[11]												
Coal (thousand tons)[1]	1,002,032	986,026[R]	884,287	762,815	790,274	908,232	929,448	880,588	862,701	826,860	831,929	769,152
Petroleum (thousand barrels)[2]	186,655	185,567[R]	120,851	124,618	108,272	145,939	181,276	128,749	113,678	89,908	149,258	154,144
Natural Gas (millions of cubic feet)[12]	5,734,054	5,500,704[R]	5,607,737	2,148,924	2,629,986	2,809,455	2,922,957	2,764,734	2,604,663	3,023,327	2,863,904	2,574,523
Cost of Fuel at Electricity Generators (cents per million Btu)[11]												
Coal[1]	136.1	128.2[R]	125.5	123.2	120.0	121.6	125.2	127.3	128.9	131.8	135.5	138.5
Petroleum[2]	429.4	433.5[R]	334.3	369.3	417.9	235.9	202.1	273.0	302.6	256.6	242.3	237.3
Natural Gas[12]	596.1	539.3[R]	356.0	448.7	430.2	257.4	238.1	276.0	264.1	198.4	223.0	256.0
Emissions (thousand metric tons)												
Carbon Dioxide (CO_2)	2,444,443	2,415,804[R]	2,395,232[R]	2,379,603	2,429,394	2,326,558	2,313,013	2,223,347	2,155,453	2,079,761	2,063,788	2,034,206
Sulfur Dioxide (SO_2)	10,307	10,643[R]	10,515	10,966	11,297	12,445	12,509	13,524	12,908	11,898	14,473	14,968
Nitrogen Oxides (NO_X)	3,951	4,326[R]	4,802	5,045	5,380	5,732	6,235	6,324	6,281	7,885	7,802	7,997
Trade (million megawatthours)[13]												
Purchases	2,779	2,669	2,664	3,074	2,346	2,040	2,021	1,966	1,798	1,618	1,528	1,492
Sales for Resale	2,961	2,972	2,766	2,900	2,355[R]	1,998[R]	1,922	1,839	1,656	1,495	1,388	1,387
Electricity Imports and Exports (thousand megawatthours)												
Imports	34,210	30,390	36,373	38,500	48,592	43,215	39,513	43,031	43,497	42,854	46,833	31,358
Exports	22,898	23,972	13,560	16,473	14,829	14,222	13,656	8,974	3,302	3,623	2,010	3,541
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	118,764	117,280[R]	116,622[R]	114,890[R]	111,718	110,383	109,048	107,066	105,343	103,917	102,321	100,860
Commercial	16,607	16,550[R]	15,334[R]	14,867[R]	14,349	14,074	13,887	13,542	13,181	12,949	12,733	12,526
Industrial	748	713[R]	602[R]	571[R]	527	553	540	563	586	581	584	553
Transportation[14]	1	1[R]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other[14]	NA	NA	1,067[R]	1,030[R]	974	935	933	952	894	882	851	795
All Sectors	136,119	134,544[R]	133,624[R]	131,359[R]	127,568	125,945	124,408	122,123	120,004	118,330	116,489	114,735

See end of table for Notes and Sources.

Table ES. Summary Statistics for the United States, 1993 through 2004 (Continued)

Description	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Retail Sales and Revenue Data – Bundled and Unbundled (Continued)												
Sales to Ultimate Customers (thousand megawatthours)												
Residential	1,293,587	1,273,597[R]	1,265,403[R]	1,201,148[R]	1,192,446	1,144,923	1,130,109	1,075,880	1,082,512	1,042,501	1,008,482	994,781
Commercial	1,229,045	1,197,199[R]	1,104,748[R]	1,087,987[R]	1,055,232	1,001,996	979,401	928,633	887,445	862,685	820,269	794,573
Industrial	1,018,522	1,011,617[R]	990,139[R]	984,511[R]	1,064,239	1,058,217	1,051,203	1,038,197	1,033,631	1,012,693	1,007,981	977,164
Transportation[14]	7,064	6,810	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other[14]	NA	NA	105,790[R]	108,445[R]	109,496	106,952	103,518	102,901	97,539	95,407	97,830	94,944
All Sectors	3,548,218	3,489,223[R]	3,466,080[R]	3,382,092[R]	3,421,414	3,312,087	3,264,231	3,145,610	3,101,127	3,013,287	2,934,563	2,861,462
Direct Use[15]	168,470	168,295	166,184	162,649	170,943	171,629	160,866	156,239	152,638	150,677	146,325	139,238
Total Disposition	3,716,688	3,657,517[R]	3,632,264[R]	3,544,740[R]	3,592,357	3,483,716	3,425,097	3,301,849	3,253,765	3,163,963	3,080,888	3,000,700
Revenue From Ultimate Customers (million dollars)												
Residential	116,037	110,794[R]	107,106[R]	103,665[R]	98,209	93,483	93,360	90,704	90,503	87,610	84,552	82,814
Commercial	100,255	95,759[R]	87,296[R]	86,536[R]	78,405	72,771	72,575	70,497	67,829	66,365	63,396	61,521
Industrial	53,661	51,794[R]	48,643[R]	49,058[R]	49,369	46,846	47,050	47,023	47,536	47,175	48,069	47,357
Transportation[14]	504	514[R]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other[14]	NA	NA	7,143[R]	8,065[R]	7,179	6,796	6,863	7,110	6,741	6,567	6,689	6,528
All Sectors	270,456	258,861[R]	250,189[R]	247,325[R]	233,163	219,896	219,848	215,334	212,609	207,717	202,706	198,220
Average Retail Price (cents per kilowatthour)												
Residential	8.97	8.70	8.46	8.63[R]	8.24	8.16	8.26	8.43	8.36	8.40	8.38	8.32
Commercial	8.16	8.00[R]	7.90[R]	7.95[R]	7.43	7.26	7.41	7.59	7.64	7.69	7.73	7.74
Industrial	5.27	5.12[R]	4.91[R]	4.98[R]	4.64	4.43	4.48	4.53	4.60	4.66	4.77	4.85
Transportation[14]	7.13	7.55[R]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other[14]	NA	NA	6.75[R]	7.44[R]	6.56	6.35	6.63	6.91	6.91	6.88	6.84	6.88
All Sectors	7.62	7.42	7.22[R]	7.31[R]	6.81	6.64	6.74	6.85	6.86	6.89	6.91	6.93
Revenue and Expense Statistics (million dollars)[16]												
Major Investor Owned												
Utility Operating Revenues	240,318	226,227	219,389	267,525	235,336	214,160	218,175	215,083	207,459	199,967	196,282	193,638
Utility Operating Expenses	207,161	197,459	188,745	235,198	210,324	182,258	186,498	182,796	173,920	165,321	164,207	161,908
Net Utility Operating Income	33,158	28,768	30,644	32,327	25,012	31,902	31,677	32,286	33,539	34,646	32,074	31,730
Major Publicly Owned (with Generation Facilities)[17]												
Operating Revenues	NA	33,906	32,776	38,028	31,843	26,767	26,155	25,397	24,207	23,473	23,267	22,522
Operating Expenses	NA	29,637	28,638	32,789	26,244	21,274	20,880	20,425	19,084	18,959	18,649	18,162
Net Electric Operating Income	NA	4,268	4,138	5,238	5,598	5,493	5,275	4,972	5,123	4,514	4,618	4,360
Major Publicly Owned (without Generation Facilities)[17]												
Operating Revenues	NA	12,454	11,546	10,417	9,904	9,354	8,790	8,586	8,582	8,435	7,996	7,523
Operating Expenses	NA	11,481	10,703	9,820	9,355	8,737	8,245	8,033	8,123	7,979	7,567	7,063
Net Electric Operating Income	NA	974	843	597	549	617	545	552	459	457	429	460
Major Federally Owned[17]												
Operating Revenues	NA	11,798	11,470	12,458	10,685	10,186	9,780	8,833	9,082	8,743	8,552	8,141
Operating Expenses	NA	8,763	8,665	10,013	8,139	7,775	7,099	5,999	6,390	6,162	6,303	6,056
Net Electric Operating Income	NA	3,035	2,805	2,445	2,546	2,411	2,681	2,834	2,692	2,581	2,249	2,085
Major Cooperative Borrower Owned												
Operating Revenues	30,650	29,228	27,458	26,458	25,629	23,824	23,988	23,321	24,424	24,609	23,777	24,873
Operating Expenses	27,828	26,361	24,561	23,763	22,982	21,283	21,223	20,715	23,149	21,741	20,993	21,675
Net Electric Operating Income	2,822	2,867	2,897	2,696	2,647	2,541	2,764	2,606	2,872	2,868	2,784	3,197
Demand-Side Management (DSM) Data												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction[18]	23,532	22,904	22,936	24,955	22,901	26,455	27,231	25,284	29,893	29,561	25,001	23,069
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119
Load Management	2,047	2,020	1,790	990[R]	875	872	392	953	1,989	2,093	2,763	4,175
DSM Cost (million dollars)												
Total Cost[19]	1,558	1,297	1,626	1,630	1,565	1,424	1,421	1,636	1,902	2,421	2,716	2,744

1 Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
2 Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology) and waste oil.
3 Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
4 Conventional hydroelectric power excluding pumped storage facilities.
5 Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, 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 Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
8 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.
9 Anthracite, bituminous, subbituminous, lignite, and synthetic coal; excludes waste coal.
10 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.
11 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. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. However, EIA does not attempt to resolve any late filing issues in the FERC Form 423 data. Beginning in 2003, estimates were developed for missing or incomplete data from some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 and 2004 data cannot be directly compared to previous years` data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes. Beginning in 2002, includes data from the Form EIA-423 for independent power producers and combined heat and power producers.
12 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.
13 Alaska and Hawaii are not included.
14 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, interdepartamental 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, now 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.

[15] 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.

[16] Unless otherwise noted, all "dollars" are nominal dollars.

[17] The Form EIA-412 has been suspended until further notice. The 1998-2003 data represent those utilities meeting a threshold of 150 million kilowatthours of sales to ultimate customers and/or 150 million kilowatthours of sales for resale for the two previous years. The 1993-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of sales to ultimate customers and/or 120 million kilowatthours of sales for resale for the two previous years.

[18] 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.

[19] Sum of the total incurred direct and indirect utility costs for the year. Utility costs reflect the total cash expenditures for the year, in nominal dollars, that flow out to support demand-side management programs.

NA = Not available.

R = Revised.

Notes: ·See Glossary reference for definitions.·See Technical Notes for the methodology used to convert short tons to metric tons.·Totals may not equal sum of components because of independent rounding.

Sources: Form EIA-411, "Coordinated Bulk Power Supply Program Report;" Form EIA-412, "Annual Electric Industry Financial Report;" 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;" Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Forma 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: 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

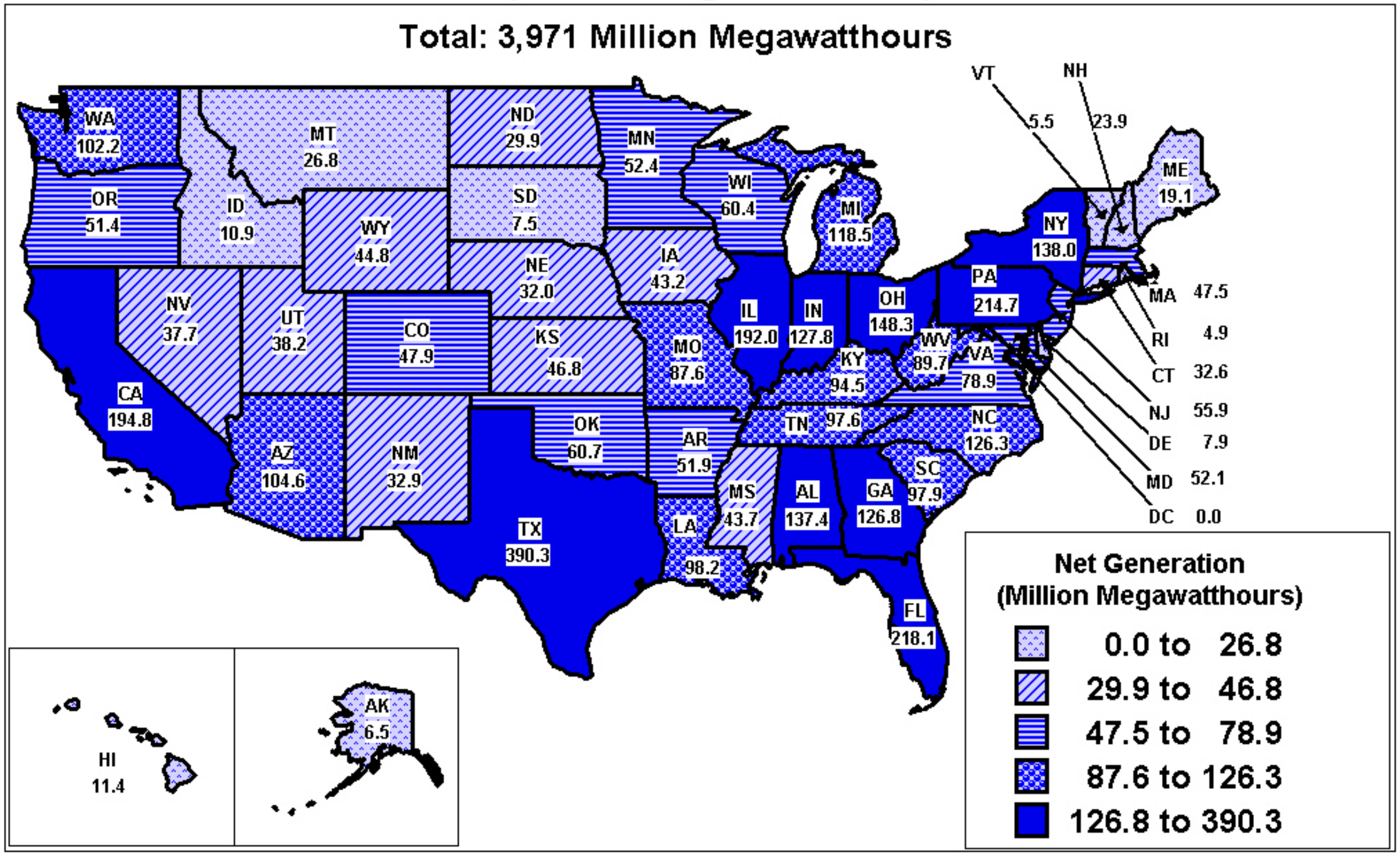
Table 1.1. Net Generation by Energy Source by Type of Producer, 1993 through 2004
(Thousand Megawatthours)

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)										
1993	1,690,070	112,788	414,927	12,956	610,291	280,494	76,213	-4,036	3,487	3,197,191
1994	1,690,694	105,901	460,219	13,319	640,440	260,126	76,535	-3,378	3,667	3,247,522
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	77,985	-8,823	4,690	3,736,644
2002	1,933,130	94,567	691,006	11,463	780,064	264,329	86,922	-8,743	5,714	3,858,452
2003	1,973,737	119,406	649,908	15,600	763,733	275,806	87,410	-8,535	6,121	3,883,185
2004	1,978,620	120,646	708,979	16,766	788,528	268,417	90,408	-8,488	6,679	3,970,555
Electricity Generators, Electric Utilities										
1993	1,639,151	99,539	258,915	--	610,291	269,098	9,565	-4,036	--	2,882,525
1994	1,635,493	91,039	291,115	--	640,440	247,071	8,933	-3,378	--	2,910,712
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	2,152	-7,704	--	2,629,946
2002	1,514,670	59,125	229,639	206	507,380	242,302	3,569	-7,434	--	2,549,457
2003	1,500,281	69,930	186,967	243	458,829	249,622	3,941	-7,532	--	2,462,281
2004	1,513,641	73,694	199,662	374	475,682	245,546	4,061	-7,526	98	2,505,231
Electricity Generators, Independent Power Producers										
1993	2,904	1,060	8,293	7	--	8,425	32,706	--	--	53,396
1994	4,370	1,047	8,603	7	--	6,934	33,554	--	--	54,514
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	42,661	-1,119	--	780,592
2002	366,535	24,150	227,155	29	272,684	18,189	46,456	-1,309	1,441	955,331
2003	415,498	38,571	234,240	13	304,904	21,890	47,753	-1,003	1,339	1,063,205
2004	407,418	35,665	291,527	7	312,846	19,518	51,483	-962	1,368	1,118,870
Combined Heat and Power, Electric Power[8]										
1993	23,409	4,827	75,013	959	--	--	3,360	--	408	107,976
1994	26,414	6,592	85,971	1,085	--	--	3,199	--	239	123,500
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	--	--	3,988	--	--	169,515
2002	29,408	6,458	150,889	1,734	--	--	4,565	--	615	193,670
2003	36,935	5,195	146,097	2,392	--	--	4,822	--	233	195,674
2004	36,134	5,208	136,331	2,645	--	--	3,578	--	364	184,259
Combined Heat and Power, Commercial[9]										
1993	864	334	4,471	100	--	100	1,132	--	*	7,000
1994	850	417	4,929	115	--	93	1,216	--	--	7,619
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	1,482	--	*	7,416
2002	992	431	4,310	*	--	13	1,585	--	84	7,415
2003	1,206	423	3,899	--	--	72	1,894	--	2	7,496
2004	1,323	469	4,051	--	--	105	2,321	--	1	8,270
Combined Heat and Power, Industrial[10]										
1993	23,742	7,028	68,234	11,890	--	2,871	29,450	--	3,079	146,294
1994	23,568	6,808	69,600	12,112	--	6,028	29,633	--	3,428	151,178
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	27,703	--	4,690	149,175
2002	21,525	4,403	79,013	9,493	--	3,825	30,747	--	3,574	152,580
2003	19,817	5,285	78,705	12,953	--	4,222	29,001	--	4,546	154,530
2004	20,103	5,610	77,409	13,740	--	3,248	28,965	--	4,849	153,925

[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] Conventional hydroelectric power excluding pumped storage facilities.
[5] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy and wind.
[6] The quantity of output from a hydroelectric pumped storage facility is where net value equals production minus energy used for pumping.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[8] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[9] Small number of commercial electricity-only plants included.
[10] Small number of Industrial electricity-only plants included.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is "1" and values under 0.5 are shown as "*".)

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Figure 1.1 U.S. Electric Power Industry Net Generation by State, 2004 (Million Megawatthours)



Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.

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, 1993 through 2004
(Billion Btus)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Other Renewables[4]	Other[5]	Total
Total Combined Heat and Power							
1993	372,603	128,884	604,256	142,044	713,009	40,731	2,001,527
1994	387,604	132,528	645,561	143,682	767,417	42,129	2,118,921
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	597,475	42,248	1,958,151
2002	336,848	72,826	708,738	117,513	584,976	34,796	1,855,697
2003	333,361	85,263	610,122	110,263	646,223	41,103	1,826,335
2004	346,083	96,439	504,548	133,821	696,936	31,251	1,809,078
Combined Heat and Power, Electric Power							
1993	29,742	7,820	106,650	3,091	24,088	1,322	172,713
1994	36,663	8,631	119,199	5,190	24,497	880	195,060
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	16,019	0	242,508
2002	40,020	3,869	214,137	5,961	17,219	63	281,269
2003	38,249	7,379	200,077	9,282	22,760	321	278,068
2004	22,153	1,250	129,791	16,043	9,388	337	178,962
Combined Heat and Power, Commercial							
1993	18,285	4,130	22,601	118	14,324	1	59,459
1994	17,759	4,483	25,578	172	14,172	--	62,164
1995	16,718	2,877	28,574	--	15,223	1	63,393
1996	19,742	2,905	32,770	*	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	*	17,145	--	77,779
2000	21,001	3,827	39,293	*	17,613	--	81,734
2001	18,495	4,118	34,923	--	14,024	--	71,560
2002	18,477	2,743	36,265	--	11,703	--	69,188
2003	22,780	2,716	16,955	--	14,438	--	56,889
2004	23,753	4,023	21,418	--	17,011	--	66,205
Combined Heat and Power, Industrial							
1993	324,576	116,934	475,005	138,835	674,597	39,408	1,769,355
1994	333,182	119,414	500,784	138,320	728,748	41,249	1,861,697
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	567,432	42,248	1,644,083
2002	278,351	66,214	458,336	111,552	556,054	34,733	1,505,240
2003	272,332	75,168	393,090	100,981	609,025	40,782	1,491,378
2004	300,177	91,166	353,339	117,778	670,537	30,914	1,563,911

[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)
[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, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy and wind.
[5] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is "1" and values under 0.5 are shown as "*".)
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, 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, 1993 through 2004
(Megawatts)

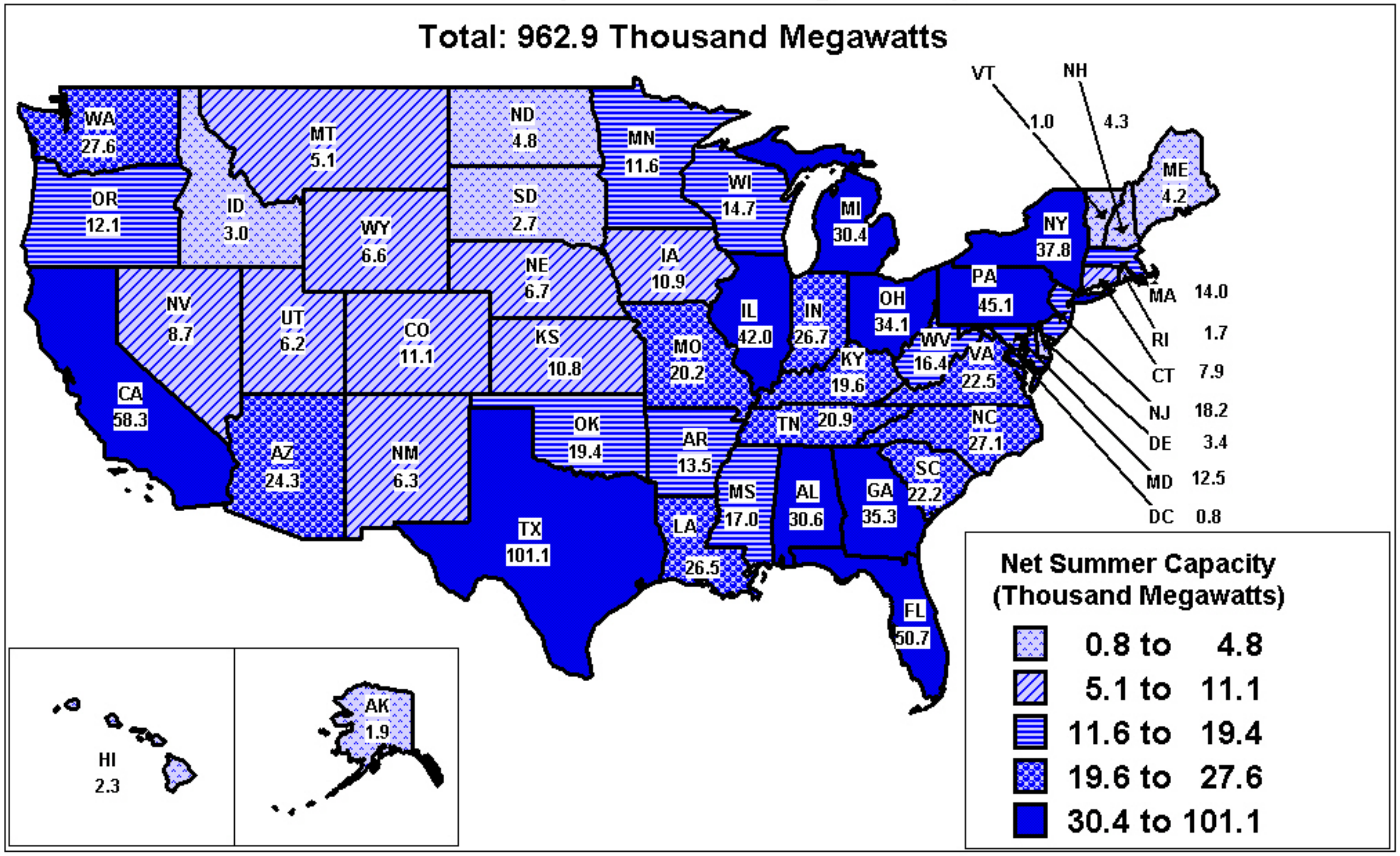
Period	Coal[1]	Petroleum[2]	Natural Gas	Dual Fired	Other Gases[3]	Nuclear	Hydro-electric[4]	Other Renewables[5]	Pumped Storage[6]	Other[7]	Total
Total (All Sectors)											
1993	310,148	44,019	65,523	120,157	1,931	99,041	77,410	14,656	21,146	550	754,582
1994	311,415	42,695	70,685	123,110	2,093	99,148	78,041	15,021	21,208	550	763,967
1995	311,386	43,708	75,438	121,958	1,661	99,515	78,562	15,300	21,387	550	769,463
1996	313,382	43,585	74,498	128,570	1,664	100,784	76,437	15,309	21,110	550	775,890
1997	313,624	43,202	76,348	129,384	1,525	99,716	79,415	15,351	19,310	774	778,649
1998	315,786	40,399	75,772	130,399	1,520	97,070	79,151	15,444	19,518	810	775,868
1999	315,496	35,587	73,562	146,039	1,909	97,411	79,393	15,942	19,565	1,023	785,927
2000	315,114	35,890	95,705	149,833	2,342	97,860	79,359	15,572	19,522	523	811,719
2001	314,230	39,714	125,798	153,482	1,670	98,159	79,484	16,180	19,096	440	848,254
2002	315,350	38,213	171,661	162,289	2,008	98,657	79,354	16,755	20,373	641	905,301
2003	313,019	36,429	208,447	171,295	1,994	99,209	78,694	18,199	20,522	638	948,446
2004	313,020	33,702	224,257	172,170	2,296	99,628	77,641	18,763	20,764	700	962,942
Electricity Generators, Electric Utilities											
1993	300,634	42,699	49,709	109,066	698	99,041	74,763	2,215	21,146	--	699,971
1994	300,941	41,296	51,239	110,633	698	99,148	74,787	2,278	21,208	--	702,229
1995	300,569	42,232	55,220	109,294	291	99,515	75,274	2,330	21,387	--	706,111
1996	302,420	42,090	52,527	115,740	63	100,784	73,129	2,079	21,110	--	709,942
1997	302,866	41,545	53,552	116,174	206	99,716	76,177	2,123	19,310	222	711,889
1998	299,739	38,144	40,764	114,201	55	97,070	75,525	2,067	18,898	229	686,692
1999	277,780	31,742	31,755	108,716	220	95,030	74,122	790	18,945	224	639,324
2000	260,990	25,823	32,069	106,806	57	85,968	73,738	837	18,020	13	604,319
2001	244,451	24,150	35,117	92,030	57	63,060	72,968	979	17,097	13	549,920
2002	244,056	23,067	50,026	88,476	61	63,202	73,391	989	17,807	--	561,074
2003	236,473	20,766	48,233	89,183	61	60,964	72,827	925	17,803	13	547,249
2004	235,976	19,878	54,231	89,040	58	60,651	71,696	960	18,048	13	550,550
Electricity Generators, Independent Power Producers											
1993	528	114	104	2,112	--	--	2,026	6,478	--	--	11,362
1994	702	117	258	2,843	--	--	2,108	6,728	--	--	12,755
1995	719	121	296	2,791	--	--	2,151	6,887	--	--	12,964
1996	719	130	386	2,834	--	--	2,171	6,850	--	--	13,091
1997	719	130	556	2,950	--	--	2,103	6,695	--	--	13,153
1998	6,132	670	9,580	8,265	--	--	2,454	6,955	620	--	34,675
1999	27,725	2,502	18,024	26,534	--	2,381	4,142	8,794	620	--	90,724
2000	44,164	8,611	35,493	34,995	--	11,892	4,509	8,994	1,502	--	150,159
2001	60,701	13,911	57,933	56,161	--	35,099	5,447	9,680	1,997	--	240,929
2002	61,770	13,997[R]	85,464	64,607[R]	12	35,455	4,911	10,435	2,564	35	279,250[R]
2003	66,538	14,412	118,694	71,546	6	38,244	5,058	11,832	2,719	--	329,049
2004	67,242	12,566	131,071	73,137	8	38,978	5,274	12,116	2,717	--	343,106
Combined Heat and Power, Electric Power[8]											
1993	3,798	263	6,332	6,407	--	--	--	464	--	--	17,263
1994	4,453	268	9,564	6,757	--	--	--	498	--	--	21,540
1995	4,756	329	10,048	6,991	--	--	--	610	--	--	22,733
1996	4,950	332	11,542	7,175	--	--	--	626	--	--	24,625
1997	4,895	333	11,553	7,583	5	--	--	707	--	--	25,076
1998	5,021	352	14,064	6,015	--	--	--	749	--	--	26,202
1999	5,230	237	11,821	8,430	--	--	--	741	--	--	26,459
2000	5,044	437	15,058	6,116	262	--	--	736	--	--	27,653
2001	4,628	371	18,027	3,799	287	--	9	791	--	28	27,940
2002	5,222	271[R]	21,924	7,344[R]	182	--	--	555	--	--	35,499[R]
2003	5,534	313	26,938	8,695	185	--	1	665	--	--	42,332
2004	5,609	320	24,825	8,132	289	--	1	555	--	--	39,731
Combined Heat and Power, Commercial[9]											
1993	283	113	302	639	--	--	31	267	--	--	1,637
1994	287	160	348	934	--	--	32	297	--	--	2,057
1995	315	182	350	950	--	--	31	303	--	--	2,131
1996	321	205	398	907	--	--	31	446	--	--	2,309
1997	314	194	412	930	--	--	32	450	--	--	2,333
1998	317	243	568	657	--	--	32	463	--	--	2,281
1999	317	262	455	771	--	--	32	465	--	--	2,302
2000	314	259	633	602	--	--	33	399	--	--	2,240
2001	295	271	1,382	596	--	--	20	348	2	--	2,912
2002	292	264	507	746	--	--	20	357	2	--	2,188
2003	347	276	501	560	--	--	22	371	--	--	2,077
2004	368	282	496	611	5	--	22	404	--	--	2,188
Combined Heat and Power, Industrial[10]											
1993	4,905	831	9,076	1,933	1,233	--	590	5,232	--	550	24,349
1994	5,032	854	9,276	1,943	1,395	--	1,115	5,221	--	550	25,386
1995	5,028	844	9,524	1,932	1,370	--	1,106	5,171	--	550	25,524
1996	4,972	828	9,645	1,913	1,602	--	1,106	5,308	--	550	25,923
1997	4,830	1,000	10,276	1,746	1,315	--	1,102	5,376	--	552	26,198
1998	4,577	989	10,796	1,260	1,465	--	1,139	5,210	--	581	26,019
1999	4,443	844	11,507	1,588	1,689	--	1,097	5,151	--	799	27,119
2000	4,601	761	12,453	1,313	2,023	--	1,079	4,607	--	510	27,348
2001	4,156	1,010	13,340	898	1,327	--	1,041	4,382	--	399	26,553
2002	4,010	615	13,740	1,116	1,752	--	1,033	4,419	--	607	27,291
2003	4,127	662	14,081	1,310	1,742	--	786	4,406	--	625	27,740
2004	3,825	657	13,635	1,250	1,937	--	648	4,728	--	687	27,367

[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, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[6] 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 lower level.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[8] Electric utility CHP plants are included in Electric Generators, Electric Utilities.
[9] Small number of commercial electricity-only plants included.
[10] Small number of industrial electricity-only plants included.
R = Revised.

Notes: • See Glossary reference for definitions. • Reporting of electric utility and independent power producer capacity at the plant-generator level became available for 2003. Some capacity in 2001 and 2002 that is classified based on the operating company's classification as an electric utility or an independent power producer is classified in 2003 based on the

individual plant generator's classification as an electric utility plant-generator or an independent power power producer plant-generator, regardless of the operating company's classification. • 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 Power Industry Existing Net Summer Capacity by State, 2004 (Thousand Megawatts)



Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.2. Existing Capacity by Energy Source, 2004
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[1]	1,526	335,243	313,020	315,364
Petroleum[2]	3,175	37,970	33,702	37,339
Natural Gas	3,048	256,627	224,257	241,391
Dual Fired	3,003	193,115	172,170	184,399
Other Gases[3]	119	2,535	2,296	2,259
Nuclear	104	105,560	99,628	101,377
Hydroelectric Conventional[4]	3,995	77,130	77,641	77,227
Other Renewables[5]	1,608	21,113	18,763	19,000
Pumped Storage	150	19,569	20,764	20,676
Other[6]	42	754	700	716
Total	**16,770**	**1,049,615**	**962,942**	**999,749**

[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] The net summer capacity and/or the net winter capacity may exceed nameplate capacity due to upgrades and overload capability of hydroelectric generators.
[5] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[6] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Notes: • Where there is more than one energy source associated with a generator, the predominant energy source is reported here. • 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, 2004
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector				
Electric Utilities	8,998	589,556	550,550	565,659
Independent Power Producers	4,560	380,868	343,106	360,447
Total	**13,558**	**970,424**	**893,656**	**926,106**
Combined Heat and Power Sector				
Electric Power[1]	686	45,974	39,731	42,547
Commercial	641	2,512	2,188	2,306
Industrial	1,885	30,705	27,367	28,791
Total	**3,212**	**79,191**	**69,286**	**73,644**
Total All Sectors	**16,770**	**1,049,615**	**962,942**	**999,749**

[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, 2005 through 2009
(Megawatts)

Energy Source	2005	2006	2007	2008	2009
Coal[1]	573	450	2,064	1,879	8,122
Petroleum[2]	432	441	186	--	8
Natural Gas	15,216	12,499	16,013	9,895	5,451
Dual Fired	4,916	1,924	5,236	2,649	1,860
Other Gases[3]	159	--	340	580	--
Nuclear	--	--	--	--	--
Hydroelectric Conventional	32	8	3	4	--
Other Renewables[4]	2,519	294	126	147	1
Pumped Storage	--	--	--	--	--
Other[5]	--	--	--	--	--
Total	**23,846**	**15,616**	**23,967**	**15,153**	**15,441**

[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, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[5] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Notes: • Projected data are updated annually, so revision superscript is not used. • Where there is more than one energy source associated with a generator, the predominant energy source is reported here. These data reflect plans as of January 1, 2005. Delays and cancellations may have occurred subsequently to the data reporting. • 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, 2005-2009
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
		2005		
U.S. Total	**267**	**23,846**	**20,877**	**22,751**
Coal[1]	8	573	537	538
Petroleum[2]	50	432	386	412
Natural Gas	105	15,216	13,049	14,458
Dual Fired	32	4,916	4,225	4,640
Other Gases[3]	4	159	135	156
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	10	32	30	29
Other Renewables[5]	58	2,519	2,515	2,518
Pumped Storage[6]	--	--	--	--
Other[7]	--	--	--	--
		2006		
U.S. Total	**111**	**15,616**	**13,475**	**14,798**
Coal[1]	1	450	422	423
Petroleum[2]	12	441	380	419
Natural Gas	75	12,499	10,728	11,841
Dual Fired	10	1,924	1,652	1,820
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	1	8	7	7
Other Renewables[5]	12	294	286	288
Pumped Storage[6]	--	--	--	--
Other[7]	--	--	--	--
		2007		
U.S. Total	**133**	**23,967**	**20,755**	**22,655**
Coal[1]	5	2,064	1,933	1,940
Petroleum[2]	5	186	158	181
Natural Gas	78	16,013	13,772	15,096
Dual Fired	37	5,236	4,483	5,001
Other Gases[3]	1	340	292	320
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	1	3	3	3
Other Renewables[5]	6	126	114	115
Pumped Storage[6]	--	--	--	--
Other[7]	--	--	--	--
		2008		
U.S. Total	**77**	**15,153**	**13,132**	**14,289**
Coal[1]	7	1,879	1,715	1,771
Petroleum[2]	--	--	--	--
Natural Gas	46	9,895	8,511	9,301
Dual Fired	17	2,649	2,268	2,530
Other Gases[3]	2	580	499	545
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	1	4	4	4
Other Renewables[5]	4	147	137	138
Pumped Storage[6]	--	--	--	--
Other[7]	--	--	--	--
		2009		
U.S. Total	**51**	**15,441**	**13,896**	**14,538**
Coal[1]	14	8,122	7,606	7,635
Petroleum[2]	1	8	7	7
Natural Gas	27	5,451	4,688	5,126
Dual Fired	8	1,860	1,594	1,769
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	--	--	--	--
Other Renewables[5]	1	1	1	1
Pumped Storage[6]	--	--	--	--
Other[7]	--	--	--	--

[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, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[6] 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 lower level.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Notes: • Projected data are updated annually, so revision superscript is not used. • Where there is more than one energy source associated with a generator, the predominant energy source is reported here. These data reflect plans as of January 1, 2005. Delays and cancellations may have occurred subsequently to the data reporting. • 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, 2004

(Megawatts)

Energy Source	Generator Additions				Generator Retirements				Updates and Revisions[1]		
	Number of Gene-rators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Number of Gene-rators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Coal[2]	4	617	553	553	13	623	543	543	-543	-8	117
Petroleum[3]	62	244	224	224	45	725	630	677	-2,514	-2,321	-2,231
Natural Gas	110	18,305	15,345	16,730	62	1,263	1,130	1,222	618	1,595	1,517
Dual Fired	47	5,565	4,776	5,166	90	4,975	4,844	4,996	1,786	944	1,196
Other Gases[4]	--	--	--	--	3	66	60	60	318	362	336
Nuclear	--	--	--	--	--	--	--	--	145	419	485
Hydroelectric	9	72	70	69	9	116	115	115	390	-765	-450
Other Renewables[5]	24	450	445	440	18	60	54	52	248	172	89
Other[6]	--	--	--	--	--	--	--	--	51	62	76
Total	**256**	**25,253**	**21,413**	**23,183**	**240**	**7,829**	**7,377**	**7,666**	**499**	**459**	**1,133**

[1] Generator re-ratings, re-powering, and revisions/corrections to previously reported 2003 data. There is not a direct correlation between these columns of data since this is a mixture of changes.

[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] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

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

[6] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Notes: • Where there is more than one energy source, the predominant energy source is reported here. • 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, 2000 through 2009
(Megawatts)

North American Electric Reliability Council Region	Actual				
	2000	2001	2002	2003	2004
Summer					
ECAR	92,033	100,235	102,996	98,487	95,300
ERCOT	57,606	55,201	56,248	59,996	58,531
FRCC	37,194	39,062	40,696	40,475	42,383
MAAC	49,477	54,015	55,569	53,566	52,049
MAIN	52,552	56,344	56,396	56,988	53,439
MRO (U.S.) [1]	28,605	28,321	29,119	28,831	29,351
NPCC (U.S.)	50,057	55,949	56,012	55,018	52,549
SERC	156,088	149,293	158,767	153,110	157,615
SPP	40,199	40,273	39,688	40,367	40,106
WECC (U.S.)	114,602	109,119	119,074	122,537	123,136
Contiguous U.S.	**678,413**	**687,812**	**714,565**	**709,375**	**704,459**
Winter					
ECAR	84,546	85,485	87,300	86,332	91,800
ERCOT	44,641	44,015	45,414	42,702	44,010
FRCC	38,606	40,922	45,635	36,841	44,839
MAAC	43,256	39,458	46,551	45,625	45,905
MAIN	41,943	40,529	42,412	41,719	42,929
MRO (U.S.) [1]	24,536	21,815	23,645	24,134	24,526
NPCC (U.S.)	43,852	42,670	46,009	48,079	48,176
SERC	139,146	135,182	141,882	137,972	144,337
SPP	30,576	29,614	30,187	28,450	29,490
WECC (U.S.)	97,324	96,622	95,951	102,020	102,689
Contiguous U.S.	**588,426**	**576,312**	**604,986**	**593,874**	**618,701**

North American Electric Reliability Council Region	Projected				
	2005	2006	2007	2008	2009
Summer					
ECAR	103,679	106,753	108,749	110,942	112,867
ERCOT	60,475	62,148	63,132	64,245	65,097
FRCC	43,495	44,680	45,962	47,108	48,344
MAAC	57,630	58,784	59,909	61,025	62,136
MAIN	59,154	60,184	61,518	62,608	63,645
MRO (U.S.) [1]	30,134	30,712	31,288	31,939	32,492
NPCC (U.S.)	58,315	59,370	60,190	61,080	61,915
SERC	165,144	168,565	173,410	176,862	180,305
SPP	41,371	42,196	42,896	43,466	44,313
WECC (U.S.)	127,935	131,128	134,784	138,117	141,518
Contiguous U.S.	**747,332**	**764,520**	**781,838**	**797,392**	**812,632**
Winter					
ECAR	90,464	92,492	93,978	95,841	97,045
ERCOT	41,672	42,922	43,803	44,092	45,732
FRCC	46,717	47,994	49,139	50,414	51,700
MAAC	46,784	47,560	48,334	49,106	49,857
MAIN	43,926	44,528	45,368	46,139	46,846
MRO (U.S.) [1]	24,995	25,413	25,828	26,322	26,704
NPCC (U.S.)	48,180	48,845	49,520	50,180	50,795
SERC	147,019	150,031	152,922	155,489	157,765
SPP	29,480	30,021	30,364	30,994	31,644
WECC (U.S.)	105,996	108,606	110,906	113,329	115,767
Contiguous U.S.	**625,233**	**638,412**	**650,162**	**661,906**	**673,855**

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

Notes: • Actual data are final. • Projected data are updated annually. • 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 March 31 of the following year. For example, winter 2001 begins December 1, 2001, and extends through March 31, 2002. • Totals may not equal sum of components because of independent rounding.

Sources: 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, 1993 through 2004
(Megawatts)

Region and Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
ECAR												
Net Internal Demand	95,300	98,487	101,251	100,235	98,651	94,072	92,359	91,103	88,573	85,643	84,967	83,530
Capacity Resources	127,919	123,755	119,736	113,136	115,379	107,451	105,545	105,106	104,953	103,003	101,605	101,910
Capacity Margin (percent)	25.5	20.4	15.4	11.4	14.5	12.5	12.5	13.3	15.6	16.9	16.4	18.0
ERCOT												
Net Internal Demand	58,531	59,282	55,833	55,106	53,649	51,697	50,254	47,746	45,636	44,990	43,630	42,629
Capacity Resources	73,850	74,764	76,849	70,797	69,622	65,423	59,788	55,771	55,230	55,074	54,219	54,323
Capacity Margin (percent)	20.7	20.7	27.3	22.2	22.9	21.0	15.9	14.4	17.4	18.3	19.5	21.5
FRCC												
Net Internal Demand	42,243	40,387	37,951	38,932	35,666	34,832	34,562	32,874	31,868	31,649	30,537	29,435
Capacity Resources	48,579	46,806	43,342	42,290	43,083	40,645	39,708	39,613	38,237	38,282	37,577	36,225
Capacity Margin (percent)	13.0	13.7	12.4	7.9	17.2	14.3	13.0	17.0	16.7	17.3	18.7	18.7
MAAC												
Net Internal Demand	52,049	53,566	54,296	54,015	51,358	49,325	47,626	46,548	45,628	45,224	44,571	44,198
Capacity Resources	66,167	65,897	63,619	59,533	60,679	57,831	55,511	56,155	56,774	56,881	56,271	55,328
Capacity Margin (percent)	21.3	18.7	14.7	9.3	15.4	14.7	14.2	17.1	19.6	20.5	20.8	20.1
MAIN												
Net Internal Demand	50,499	53,617	53,267	53,032	51,845	47,165	45,570	45,194	44,470	43,229	42,611	42,001
Capacity Resources	65,677	67,410	67,025	65,950	64,170	55,984	52,722	52,160	52,880	52,112	50,963	50,333
Capacity Margin (percent)	23.1	20.5	20.5	19.6	19.2	15.8	13.6	13.4	15.9	17.0	16.4	16.6
MRO (U.S.)[1]												
Net Internal Demand	29,094	28,775	28,825	27,125	28,006	30,606	29,766	28,221	27,298	27,487	26,855	25,901
Capacity Resources	35,830	33,287	34,259	32,271	34,236	35,373	34,773	34,027	33,121	32,665	32,267	31,964
Capacity Margin (percent)	18.8	13.6	15.9	15.9	18.2	13.5	14.4	17.1	17.6	15.9	16.8	19.0
NPCC (U.S.)												
Net Internal Demand	51,580	53,936	55,164	55,888	54,270	53,450	51,760	50,240	48,950	48,290	47,465	46,380
Capacity Resources	71,532	70,902	66,208	63,760	63,376	63,077	60,439	60,729	58,592	62,368	61,906	62,049
Capacity Margin (percent)	27.9	23.9	16.7	12.3	14.4	15.3	14.4	17.3	16.5	22.6	23.3	25.3
SERC												
Net Internal Demand	153,024	148,380	154,459	144,399	151,527	142,726	138,146	134,968	109,270	105,785	101,885	99,287
Capacity Resources	182,861	177,231	172,485	171,530	169,760	160,575	158,360	155,016	126,196	127,562	120,044	117,375
Capacity Margin (percent)	16.3	16.3	10.5	15.8	10.7	11.1	12.8	12.9	13.4	17.1	15.1	15.4
SPP												
Net Internal Demand	39,383	39,428	38,298	38,807	39,056	37,807	36,402	37,009	59,017	57,951	56,395	55,067
Capacity Resources	48,000	45,802	47,233	45,530	46,109	43,111	42,554	43,591	69,344	69,354	69,198	67,922
Capacity Margin (percent)	18.0	13.9	18.9	14.8	15.3	12.3	14.5	15.1	14.9	16.4	18.5	18.9
WECC (U.S.)												
Net Internal Demand	121,205	120,894	117,032	107,294	116,913	112,177	111,641	104,486	101,728	99,612	99,724	96,613
Capacity Resources	155,455	150,277	142,624	124,193	141,640	136,274	135,270	135,687	135,049	130,180	127,533	127,931
Capacity Margin (percent)	22.0	19.6	17.9	13.6	17.5	17.7	17.5	23.0	24.7	23.5	21.8	24.5
Contiguous U.S.												
Net Internal Demand	**692,908**	**696,752**	**696,376**	**674,833**	**680,941**	**653,857**	**638,086**	**618,389**	**602,438**	**589,860**	**578,640**	**565,041**
Capacity Resources	**875,870**	**856,131**	**833,380**	**788,990**	**808,054**	**765,744**	**744,670**	**737,855**	**730,376**	**727,481**	**711,583**	**705,360**
Capacity Margin (percent)	**20.9**	**18.6**	**16.4**	**14.5**	**15.7**	**14.6**	**14.3**	**16.2**	**17.5**	**18.9**	**18.7**	**19.9**

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

Notes: • NERC Regional Council names may be found in the Glossary reference. • In 1998, several utilities realigned from SPP to SERC. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • Totals may not equal sum of components because of independent rounding.

Sources: 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, 2004 through 2009

(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand	Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Capacity Resources	Capacity Margin (percent)
		2004			2005	
ECAR	95,300	127,919	25.5	101,171	128,700	21.4
ERCOT	58,531	73,850	20.7	59,325	69,309	14.4
FRCC	42,243	48,579	13.0	40,505	50,494	19.8
MAAC	52,049	66,167	21.3	56,817	68,300	16.8
MAIN	50,499	65,677	23.1	55,725	66,070	15.7
MRO (U.S.)[1]	29,094	35,830	18.8	29,865	35,633	16.2
NPCC (U.S.)	51,580	71,532	27.9	57,023	68,798	17.1
SERC	153,024	182,861	16.3	160,099	183,152	12.6
SPP	39,383	48,000	18.0	40,449	47,972	15.7
WECC (U.S.)	121,205	155,455	22.0	125,475	161,328	22.2
Contiguous U.S.	**692,908**	**875,870**	**20.9**	**726,454**	**879,756**	**17.4**
		2006			2007	
ECAR	104,230	128,326	18.8	106,250	128,326	17.2
ERCOT	60,998	69,218	11.9	61,982	70,207	11.7
FRCC	41,934	51,106	17.9	43,219	51,784	16.5
MAAC	57,981	69,855	17.0	59,116	69,206	14.6
MAIN	56,731	66,729	15.0	58,052	67,119	13.5
MRO (U.S.)[1]	30,442	35,965	15.4	31,017	36,660	15.4
NPCC (U.S.)	58,078	69,917	16.9	58,898	71,386	17.5
SERC	163,579	182,569	10.4	168,602	184,522	8.6
SPP	41,262	48,710	15.3	41,950	49,243	14.8
WECC (U.S.)	128,692	166,946	22.9	132,334	171,159	22.7
Contiguous U.S.	**743,927**	**889,341**	**16.4**	**761,420**	**899,612**	**15.4**
		2008			2009	
ECAR	108,423	128,326	15.5	110,347	128,326	14.0
ERCOT	63,095	72,398	12.8	63,947	72,422	11.7
FRCC	44,364	52,909	16.2	45,590	54,249	16.0
MAAC	60,232	71,799	16.1	61,343	71,799	14.6
MAIN	59,137	68,290	13.4	60,169	68,967	12.8
MRO (U.S.)[1]	31,667	37,099	14.6	32,219	37,649	14.4
NPCC (U.S.)	59,788	71,126	15.9	60,623	70,645	14.2
SERC	172,058	186,711	7.8	175,495	190,275	7.8
SPP	42,498	49,599	14.3	43,305	49,767	13.0
WECC (U.S.)	135,655	176,305	23.1	139,047	177,635	21.7
Contiguous U.S.	**776,917**	**914,562**	**15.1**	**792,085**	**921,734**	**14.1**

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

Notes: • Actual data are final. • 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. • Totals may not equal sum of components because of independent rounding.

Sources: 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, 2004 through 2009
(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand	Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Capacity Resources	Capacity Margin (percent)
		2004/ 2005			**2005/ 2006**	
ECAR	91,800	131,187	30.0	88,438	133,952	34.0
ERCOT	44,010	71,902	38.8	40,522	73,343	44.8
FRCC	41,449	51,196	19.0	43,327	54,425	20.4
MAAC	45,565	69,604	34.5	46,444	70,799	34.4
MAIN	40,618	66,414	38.8	41,218	68,219	39.6
MRO (U.S.)[1]	24,446	34,371	28.9	24,915	34,578	27.9
NPCC (U.S.)	47,859	74,277	35.6	47,863	73,272	34.7
SERC	139,486	186,784	25.3	142,224	186,463	23.7
SPP	29,096	49,681	41.4	29,036	49,361	41.2
WECC (U.S.)	101,002	149,360	32.4	104,110	153,337	32.1
Contiguous U.S.	**605,331**	**884,776**	**31.6**	**608,097**	**897,749**	**32.3**
		2006/ 2007			**2007/ 2008**	
ECAR	90,526	133,243	32.1	92,032	133,243	30.9
ERCOT	41,772	71,927	41.9	42,653	72,059	40.8
FRCC	44,608	55,597	19.8	45,758	56,394	18.9
MAAC	47,230	71,379	33.8	48,004	72,563	33.8
MAIN	41,811	68,656	39.1	42,656	68,963	38.1
MRO (U.S.)[1]	25,333	34,439	26.4	25,748	35,282	27.0
NPCC (U.S.)	48,528	74,971	35.3	49,203	76,314	35.5
SERC	145,256	187,312	22.5	148,112	188,027	21.2
SPP	29,575	49,265	40.0	29,916	49,169	39.2
WECC (U.S.)	106,745	158,941	32.8	109,056	164,566	33.7
Contiguous U.S.	**621,384**	**905,730**	**31.4**	**633,138**	**916,580**	**30.9**
		2008/ 2009			**2009/ 2010**	
ECAR	93,915	133,243	29.5	95,184	133,243	28.6
ERCOT	42,942	73,746	41.8	44,582	74,101	39.8
FRCC	47,028	57,074	17.6	48,316	58,805	17.8
MAAC	48,776	73,774	33.9	49,527	73,774	32.9
MAIN	43,404	70,058	38.0	44,106	70,905	37.8
MRO (U.S.)[1]	26,242	35,707	26.5	26,616	36,364	26.8
NPCC (U.S.)	49,863	75,427	33.9	50,478	74,297	32.1
SERC	150,680	189,984	20.7	153,122	192,416	20.4
SPP	30,545	49,588	38.4	31,193	49,775	37.3
WECC (U.S.)	111,464	167,030	33.3	113,895	168,028	32.2
Contiguous U.S.	**644,859**	**925,631**	**30.3**	**657,019**	**931,708**	**29.5**

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

Notes: • Actual data are final. • 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 winter peak period begins on December 1 and extends through March 31 of the following year. For example, winter 2003/2004 begins December 1, 2003, and extends through March 31, 2004. • Totals may not equal sum of components because of independent rounding.

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

Chapter 4. Fuel

Table 4.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1993 through 2004

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)				
1993	842,153	192,462	3,928,653	136,230
1994	848,796	183,618	4,367,148	136,381
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	1,026,011	209,496	6,111,307	186,963
Electricity Generators, Electric Utilities				
1993	813,508	168,556	2,682,440	--
1994	817,270	155,377	2,987,146	--
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	124,532	1,808,836	5,163
Electricity Generators, Independent Power Producers				
1993	3,050	1,965	72,653	122
1994	3,939	1,998	77,414	96
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	222,544	63,057	2,329,324	86
Combined Heat and Power, Electric Power[4]				
1993	13,293	8,513	589,147	11,895
1994	14,904	12,011	693,923	11,928
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	20,305	10,619	1,162,731	33,202
Combined Heat and Power, Commercial[5]				
1993	404	672	37,435	1,115
1994	404	694	40,828	1,172
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	45,876	--
Combined Heat and Power, Industrial[6]				
1993	11,898	12,755	546,978	123,098
1994	12,279	13,537	567,836	123,185
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	10,099	764,539	148,512

[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 Electric Generators, Electric Utilities.
[5] Small number of commercial electricity-only plants included.
[6] Small number of industrial electricity-only plants included.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is "1" and values under 0.5 are shown as "*".)
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Forma 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, 1993 through 2004

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				
1993	19,750	26,394	733,584	177,554
1994	20,609	27,929	784,015	179,595
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	137,838
2004	18,786	19,860	614,760	167,272
Electric Power[4]				
1993	1,794	1,591	128,743	3,865
1994	2,241	1,791	144,062	6,487
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	1,195	280	162,256	20,053
Commercial				
1993	968	843	27,738	148
1994	940	931	31,457	215
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	26,196	--
Industrial				
1993	16,988	23,960	577,103	173,541
1994	17,428	25,207	608,496	172,893
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	126,237
2004	16,276	18,758	426,308	147,219

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

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

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Forma 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, 1993 through 2004

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1993	861,904	218,855	4,662,236	313,784
1994	869,405	211,547	5,151,163	315,976
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	229,356	6,726,067	354,236
Electricity Generators, Electric Utilities				
1993	813,508	168,556	2,682,440	--
1994	817,270	155,377	2,987,146	--
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	--
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,532	1,808,836	5,163
Electricity Generators, Independent Power Producers				
1993	3,050	1,965	72,653	--
1994	3,939	1,998	77,414	--
1995	3,921	2,342	91,064	--
1996	4,143	2,169	91,617	--
1997	3,884	4,010	70,774	--
1998	9,486	9,676	285,878	--
1999	30,572	30,037	615,756	--
2000	107,745	45,011	1,049,636	--
2001	139,799	60,489	1,477,643	--
2002	192,274	44,993	1,998,782	--
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,084	86
Combined Heat and Power, Electric Power				
1993	15,087	10,104	717,890	15,760
1994	17,145	13,803	837,985	18,415
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	53,255
Combined Heat and Power, Commercial				
1993	1,373	1,515	65,173	1,263
1994	1,344	1,625	72,285	1,387
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	--
Combined Heat and Power, Industrial				
1993	28,886	36,715	1,124,081	296,639
1994	29,707	38,744	1,176,332	296,078
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	252,976
2004	26,613	28,857	1,190,847	295,731

[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.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Forma 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, 1993 through 2004

Period	Electric Power Sector		Electric Utilities		Independent Power Producers[1]	
	Coal (Thousand Tons)[2]	Petroleum (Thousand Barrels)[3]	Coal (Thousand Tons)[2]	Petroleum (Thousand Barrels)[3]	Coal (Thousand Tons)[2]	Petroleum (Thousand Barrels)[3]
1993	111,341	62,890	111,341	62,890	NA	NA
1994	126,897	63,333	126,897	63,333	NA	NA
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

[1] Electricity only and combined-heat-and-power plants in NAICS 22 category whose primary business is to sell electricity or electricity and heat to the public.
[2] Anthracite, bituminous, subbituminous, lignite, and synthetic coal, excludes waste coal.
[3] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology). Data prior to 2004 includes small quantities of waste oil.

NA = Not available.

Notes: • Values are estimates based on a cutoff model sample - see Technical Notes for a discussion of the sample design for Form EIA-906. See Technical Notes for the adjustment methodology. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Forma 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, 1993 through 2004

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)
1993	769,152	138.5	28.58	1.18	154,144	237.3	14.95	1.34	2,574,523	256.0	159.4
1994	831,929	135.5	28.03	1.17	149,258	242.3	15.19	1.23	2,863,904	223.0	152.5
1995	826,860	131.8	27.01	1.08	89,908	256.6	16.10	1.21	3,023,327	198.4	145.2
1996	862,701	128.9	26.45	1.10	113,678	302.6	18.98	1.26	2,604,663	264.1	151.8
1997	880,588	127.3	26.16	1.11	128,749	273.0	17.18	1.37	2,764,734	276.0	152.0
1998	929,448	125.2	25.64	1.06	181,276	202.1	12.71	1.48	2,922,957	238.1	143.5
1999	908,232	121.6	24.72	1.01	145,939	235.9	14.81	1.51	2,809,455	257.4	143.8
2000	790,274	120.0	24.28	.93	108,272	417.9	26.30	1.33	2,629,986	430.2	173.5
2001	762,815	123.2	24.68	.89	124,618	369.3	23.20	1.42	2,148,924	448.7	173.0
2002[4]	884,287	125.5	25.52	.94	120,851	334.3	20.77	1.64	5,607,737	356.0	151.5
2003[5,R]	986,026	128.2	26.00	.97	185,567	433.5	26.78	1.53	5,500,704	539.3	228.2
2004	1,002,032	136.1	27.42	.97	186,655	429.4	26.56	1.66	5,734,054	596.1	256.7

[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] 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, "Monthly Cost and Quality of Fuels for Electric Plants Report" for independent power producers and combined heat and power producers are included in this data dissemination. 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.
[5] Beginning in 2003, estimates were developed for missing or incomplete data for some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 and 2004 data cannot be directly compared to previous years` data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes.
R = Revised.

Notes: • Totals may not equal sum of components because of independent rounding. • 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. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. Nonutility data include fuel delivered to electric generating plants with a total fossil-fueled nameplate generating capacity of 50 or more megawatts; utility data include fuel delivered to plants whose total fossil-fueled steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity is 50 or more megawatts. • Mcf = thousand cubic feet. • Monetary values are expressed in nominal terms.

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, 1993 through 2004

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
1993	392	.69	33.0	422,690	1.71	10.2	265,180	.41	7.0	80,890	.94	14.4
1994	689	.56	36.8	456,733	1.69	10.1	295,752	.41	6.9	78,756	.94	13.8
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	65,600	.93	13.3
2003[3]	--	--	--	436,809[R]	1.49	9.9[R]	432,513[R]	.38[R]	6.4	79,869[R]	1.03[R]	14.4[R]
2004	--	--	--	441,186	1.50	10.3	445,603	.36	6.0	78,268	1.05	14.2

[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, "Monthly Cost and Quality of Fuels for Electric Plants Report" for independent power producers and combined heat and power producers are included in this data dissemination. 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.
[3] Beginning in 2003, estimates were developed for missing or incomplete data for some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 and 2004 data cannot be directly compared to previous years` data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes.
R = Revised.

Notes: • Totals may not equal sum of components because of independent rounding. • Data do not include waste coal and synthetic coal. • 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. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. Nonutility data include fuel delivered to electric generating plants with a total fossil-fueled nameplate generating capacity of 50 or more megawatts; utility data include fuel delivered to plants whose total fossil-fueled steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity is 50 or more megawatts.

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, 1993 through 2004

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
1993	10,315	1.18	9.55	149,983	1.34	1,023
1994	10,338	1.17	9.36	149,324	1.23	1,023
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]	10,157	.94	8.74	143,493	1.64	1,021
2003[5,R]	10,137	.97	8.98	147,086	1.53	1,030
2004	10,074	.97	8.97	147,286	1.66	1,027

[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] 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, "Monthly Cost and Quality of Fuels for Electric Plants Report" for independent power producers and combined heat and power producers are included in this data dissemination. 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.
[5] Beginning in 2003, estimates were developed for missing or incomplete data for some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 and 2004 data cannot be directly compared to previous years` data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes.
R = Revised.

Notes: • Totals may not equal sum of components because of independent rounding. • 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. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. Nonutility data include fuel delivered to electric generating plants with a total fossil-fueled nameplate generating capacity of 50 or more megawatts; utility data include fuel delivered to plants whose total fossil-fueled steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity is 50 or more megawatts.

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 for Electricity Production and Useful Thermal Output at Combined-Heat-and-Power Plants, 1993 through 2004
(Thousand Metric Tons)

Emission	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Carbon Dioxide (CO_2)[1]	2,444,443	2,415,804[R]	2,395,232[R]	2,379,603	2,429,394	2,326,558	2,313,013	2,223,347	2,155,453	2,079,761	2,063,788	2,034,206
Sulfur Dioxide (SO_2) [1]........	10,307	10,643[R]	10,515	10,966	11,297	12,445	12,509	13,524	12,908	11,898	14,473	14,968
Nitrogen Oxides (NO_x) [1].....	3,951	4,326[R]	4,802	5,045	5,380	5,732	6,235	6,324	6,281	7,885	7,802	7,997

[1] For 2003, all data have been restated using a revised methodology. For 2002, only the carbon dioxide values have been revised. The revisions reflect changes to the estimation methodology and the emission factors (for the current list of emission factors, see Table A1). All other years will be revised in the next issue of the Electric Power Annual.

R = Revised.

Note: See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates.

Table 5.2. Number and Capacity of Fossil-Fueled Steam-Electric Generators with Environmental Equipment, 1993 through 2004

Year[1]	Scrubbers		Particulate Collectors		Cooling Towers		Total[2]	
	Number of Generators	Capacity[3] (megawatts)	Number of Generators	Capacity[3] (megawatts)	Number of Generators	Capacity[3] (megawatts)	Number of Generators	Capacity[3] (megawatts)
1993....................................	154	71,106	1,156	350,808	486	164,807	1,330	376,831
1994....................................	168	80,617	1,135	351,180	480	165,452	1,309	376,899
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

[1] Includes plants under the Clean Air Act that were monitored by the Environmental Protection Agency even if sold to an unregulated entity.

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

[3] Nameplate capacity

Notes: • These data are for plants with a fossil-fueled steam-electric capacity of 100 megawatts or more . • 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." Data for unregulated plants are included beginning with 2001 data.

Table 5.3. Average Flue Gas Desulfurization Costs, 1993 through 2004

Year[1]	Average Overhead & Maintenance Costs (mills per kilowatthour)[2]	Average Installed Capital Costs (dollars per kilowatt)
1993..	1.19	125.00
1994..	1.14	127.00
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

[1] Includes plants under the Clean Air Act that were monitored by the Environmental Protection Agency even if sold to an unregulated entity.

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

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. • 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." Data for unregulated plants are included beginning with 2001 data.

Chapter 6. Trade

Table 6.1. Electric Power Industry - Purchases, 1993 through 2004
(Thousand Megawatthours)

	2004	2003	2002	2001[1]	2000	1999	1998	1997	1996	1995	1994	1993
U.S. Total	**2,778,804**	**2,668,989**	**2,663,607**	**3,073,611**	**2,345,540**	**2,039,969**	**2,020,622**	**1,966,447**	**1,797,720**	**1,617,715**	**1,528,222**	**1,492,370**
Electric Utilities........	2,675,148	2,563,947	2,579,671	2,976,254	2,250,382	1,949,574	1,927,198	1,878,099	1,694,192	1,528,068	1,435,591	1,407,419
IPP............................	25,623	37,921	15,801	97,357[2]	10,622	4,358	4,089	1,647	7,713	3,760	4,221	2,449
CHP..........................	78,033	67,122	68,135	NA	84,536	86,037	89,334	86,701	95,814	85,887	88,410	82,502

[1] 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.
[2] For 2001, CHP purchases are combined with IPP data.
NA = Not available.

Notes: • IPP are independent power producers and CHP are combined heat and power producers. • See Glossary reference for definitions. • Restructuring of the electric power industry has dramatically increased trade in various locations. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report," For unregulated entities prior to 2001, Form EIA-860B, "Annual Electric Generator Report - Nonutility," Energy Information Administration, Form EIA-920 "Combined Heat and Power Plant Report," and predecessor forms.

Table 6.2. Electric Power Industry - Sales for Resale, 1993 through 2004
(Thousand Megawatthours)

	2004	2003	2002	2001[1]	2000	1999	1998	1997	1996	1995	1994	1993
U.S. Total	**2,961,369**	**2,972,466**	**2,766,242**	**2,899,787**	**2,355,154[R]**	**1,998,090[R]**	**1,921,858[R]**	**1,838,539**	**1,656,090**	**1,495,015**	**1,387,966**	**1,387,137**
Electric Utilities........	1,872,078	1,781,761	1,793,748	2,087,789	1,715,582	1,635,614	1,664,081	1,616,318	1,431,179	1,276,356	1,185,352	1,200,047
IPP............................	1,063,965	1,156,796	943,531	811,998[2]	611,150	335,122	228,617	192,299	194,361	187,453	168,927	151,129
CHP..........................	25,326	33,909	28,963	NA	28,421	27,354	29,160	29,922	30,550	31,206	33,687	35,961

[1] 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.
[2] For 2001, CHP purchases are combined with IPP data.
NA = Not available.R = Revised.

Notes: • IPP are independent power producers and CHP are combined heat and power producers. • Restructuring of the electric power industry has dramatically increased trade in various locations. • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report," For unregulated entities prior to 2001, Form EIA-860B, "Annual Electric Generator Report - Nonutility," Energy Information Administration, Form EIA-920 "Combined Heat and Power Plant Report," and predecessor forms.

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1993 through 2004
(Megawatthours)

Description	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Electricity Imports and Exports												
Canada												
Imports..................	33,007,479	29,319,707	36,130,480	38,401,598	48,515,476	42,911,308	39,502,108	43,008,501	42,233,376	40,596,119	44,821,858	29,364,197
Exports..................	22,482,109	23,582,184	12,995,708	16,105,612	12,684,706	12,953,488	11,683,276	7,470,332	1,986,361	2,468,244	941,214	2,691,723
Mexico[1]												
Imports[2]................	1,202,576	1,069,926	242,597	98,649	76,800	303,439	11,249	22,729	1,263,152	2,257,411	2,011,319	1,993,328
Exports..................	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	1,068,668	849,167
Total Imports.......	**34,210,055**	**30,389,633**	**36,373,077**	**38,500,247**	**48,592,276**	**43,214,747**	**39,513,357**	**43,031,230**	**43,496,528**	**42,853,530**	**46,833,177**	**31,357,525**
Total Exports.......	**22,897,863**	**23,972,374**	**13,560,311**	**16,473,292**	**14,829,382**	**14,221,772**	**13,656,479**	**8,974,039**	**3,301,986**	**3,622,665**	**2,009,882**	**3,540,890**

[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.
[2] Includes contract terminations in 1997 and 2000.

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

Sources: Canada: National Energy Board of Canada; Mexico: Office of Fuels Programs, Fossil Energy, Form FE-781R, "Annual Report of International Electric Export/Import Data," Data provided by the California - ISO.

Chapter 7. Retail Customers, Sales, and Revenue

Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1993 through 2004
(Number)

Period	Residential	Commercial	Industrial	Transportation[1]	Other[1]	All Sectors
Total Electric Industry						
1993	100,860,071	12,526,377	553,231	NA	795,298	114,734,977
1994	102,320,846	12,733,153	583,935	NA	850,770	116,488,704
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	114,890,240R	14,867,490R	571,463R	NA	1,030,046R	131,359,239R
2002	116,622,037R	15,333,700R	601,744R	NA	1,066,554R	133,624,035R
2003	117,280,481R	16,549,519R	713,221R	1,127R	NA	134,544,348R
2004	118,763,768	16,606,783	747,600	1,026	NA	136,119,177
Full-Service Providers[2]						
1993	100,860,071	12,526,377	553,231	NA	795,298	114,734,977
1994	102,320,846	12,733,153	583,935	NA	850,770	116,488,704
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	112,469,074R	14,353,010R	548,118R	NA	1,000,446R	128,370,648R
2002	113,790,812R	14,899,747R	586,217R	NA	1,035,604R	130,312,380R
2003	115,029,545R	16,136,616R	695,616R	1,042R	NA	131,862,819R
2004	116,325,747	16,161,269	733,809	941	NA	133,221,766
Energy-Only Providers						
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
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	2,421,166R	514,480R	23,345R	NA	29,600R	2,988,591R
2002	2,831,225R	433,953R	15,527R	NA	30,950R	3,311,655R
2003	2,250,936R	412,903R	17,605R	85R	NA	2,681,529R
2004	2,438,021	445,514	13,791	85	NA	2,897,411

[1] 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.

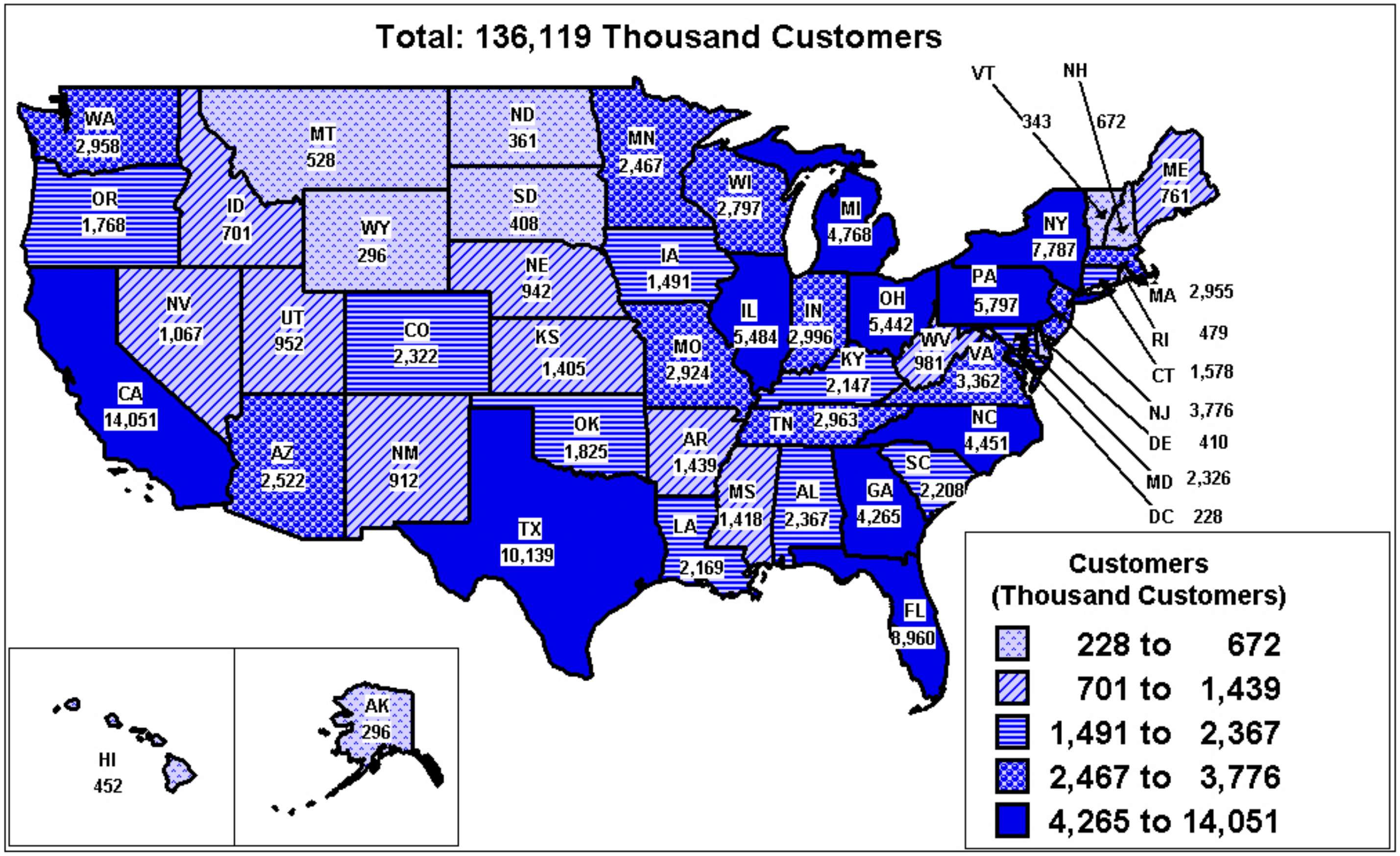
[2] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."

NA = Not available.R = Revised.

Notes: • See Glossary reference for definitions. • The number of ultimate customers is an average of the number of customers at the close of each month. • 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. • 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.

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

Figure 7.1 U.S. Electric Power Industry
Total Ultimate Customers by State, 2004



Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 7.2. Direct Use and Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1993 through 2004

(Megawatthours)

Period	Sales					End Use		
	Residential	Commercial	Industrial	Transportation[1]	Other[1]	Retail Sales	Direct Use[2]	All Sectors
Total Electric Industry								
1993	994,780,818	794,573,370	977,164,250	NA	94,943,902	2,861,462,340	139,237,877	3,000,700,217
1994	1,008,481,682	820,269,462	1,007,981,245	NA	97,830,475	2,934,562,864	146,325,334	3,080,888,198
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	1,201,147,845[R]	1,087,987,334[R]	984,511,441[R]	NA	108,444,967[R]	3,382,091,587[R]	162,648,615	3,544,740,202[R]
2002	1,265,402,563[R]	1,104,747,665[R]	990,139,177[R]	NA	105,790,481[R]	3,466,079,886[R]	166,184,296	3,632,264,182[R]
2003	1,273,597,170[R]	1,197,198,591[R]	1,011,617,409[R]	6,809,728[R]	NA	3,489,222,898[R]	168,294,526	3,657,517,424[R]
2004	1,293,586,727	1,229,044,631	1,018,521,753	7,064,414	NA	3,548,217,525	168,470,002	3,716,687,527
Full-Service Providers[3]								
1993	994,780,818	794,573,370	977,164,250	NA	94,943,902	2,861,462,340	NA	2,861,462,340
1994	1,008,481,682	820,269,462	1,007,981,245	NA	97,830,475	2,934,562,864	NA	2,934,562,864
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	1,167,277,270[R]	1,017,027,993[R]	943,159,608[R]	NA	99,219,014[R]	3,226,683,885[R]	NA	3,226,683,885[R]
2002	1,232,772,483[R]	1,016,863,807[R]	931,333,390[R]	NA	102,082,265[R]	3,283,051,945[R]	NA	3,283,051,945[R]
2003	1,240,445,871[R]	1,089,687,808[R]	924,922,536[R]	3,315,043[R]	NA	3,258,371,258[R]	NA	3,258,371,258[R]
2004	1,253,237,486	1,090,334,462	928,322,017	3,012,647	NA	3,274,906,612	NA	3,274,906,612
Energy-Only Providers								
1993	--	--	--	--	--	--	--	--
1994	--	--	--	--	--	--	--	--
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	33,870,575[R]	70,959,341[R]	41,351,833[R]	NA	9,225,953[R]	155,407,702[R]	NA	155,407,702[R]
2002	32,630,080[R]	87,883,858[R]	58,805,787[R]	NA	3,708,216[R]	183,027,941[R]	NA	183,027,941[R]
2003	33,151,299[R]	107,510,783[R]	86,694,873[R]	3,494,685[R]	NA	230,851,640[R]	NA	230,851,640[R]
2004	40,349,241	138,710,169	90,199,736	4,051,767	NA	273,310,913	NA	273,310,913

[1] 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.

[2] 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.

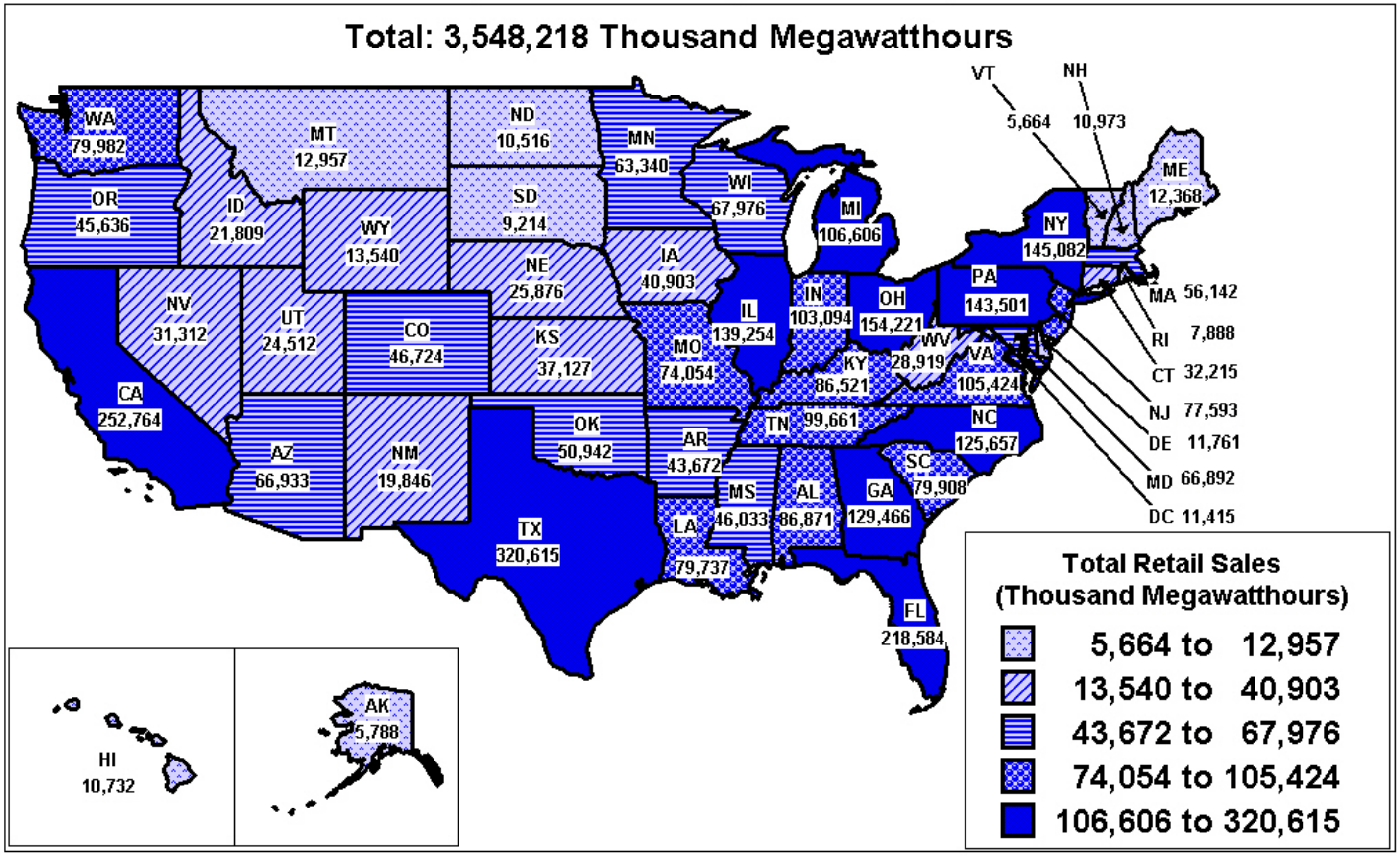
[3] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."

NA = Not available.R = Revised.

Notes: • See Glossary reference for definitions. • Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within limits specified by a rate schedule. • 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.

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

Figure 7.2 U.S. Electric Power Industry Total Retail Sales by State, 2004 (Thousand Megawatthours)



Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.
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, 1993 through 2004
(Million Dollars)

Period	Residential	Commercial	Industrial	Transportation[1]	Other[1]	All Sectors
Total Electric Industry						
1993	82,814	61,521	47,357	NA	6,528	198,220
1994	84,552	63,396	48,069	NA	6,689	202,706
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	103,665[R]	86,536[R]	49,058[R]	NA	8,065[R]	247,325[R]
2002	107,106[R]	87,296[R]	48,643[R]	NA	7,143[R]	250,189[R]
2003	110,794[R]	95,759[R]	51,794[R]	514[R]	NA	258,861[R]
2004	116,037	100,255	53,661	504	NA	270,456
Full-Service Providers[2]						
1993	82,814	61,521	47,357	NA	6,528	198,220
1994	84,552	63,396	48,069	NA	6,689	202,706
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	99,982[R]	79,743[R]	46,232[R]	NA	7,246[R]	233,204[R]
2002	102,847[R]	78,073[R]	44,185[R]	NA	6,758[R]	231,864[R]
2003	106,878[R]	84,871[R]	45,998	226[R]	NA	237,974[R]
2004	110,914	86,216	47,360	221	NA	244,711
Energy-Only Providers[3]						
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
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	2,599[R]	5,155[R]	2,295[R]	NA	686[R]	10,736[R]
2002	2,388[R]	5,778[R]	3,122[R]	NA	181[R]	11,469[R]
2003	2,225[R]	6,857[R]	4,199[R]	216[R]	NA	13,497[R]
2004	3,069	9,132	4,560	203	NA	16,964
Delivery-Only Service						
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	593	1,527	531	NA	116	2,767
2001	1,084[R]	1,638[R]	531[R]	NA	132[R]	3,386[R]
2002	1,871[R]	3,444[R]	1,336[R]	NA	204[R]	6,855[R]
2003	1,690[R]	4,031[R]	1,597	72[R]	NA	7,390[R]
2004	2,054	4,907	1,740	80	NA	8,780

[1] 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.

[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."

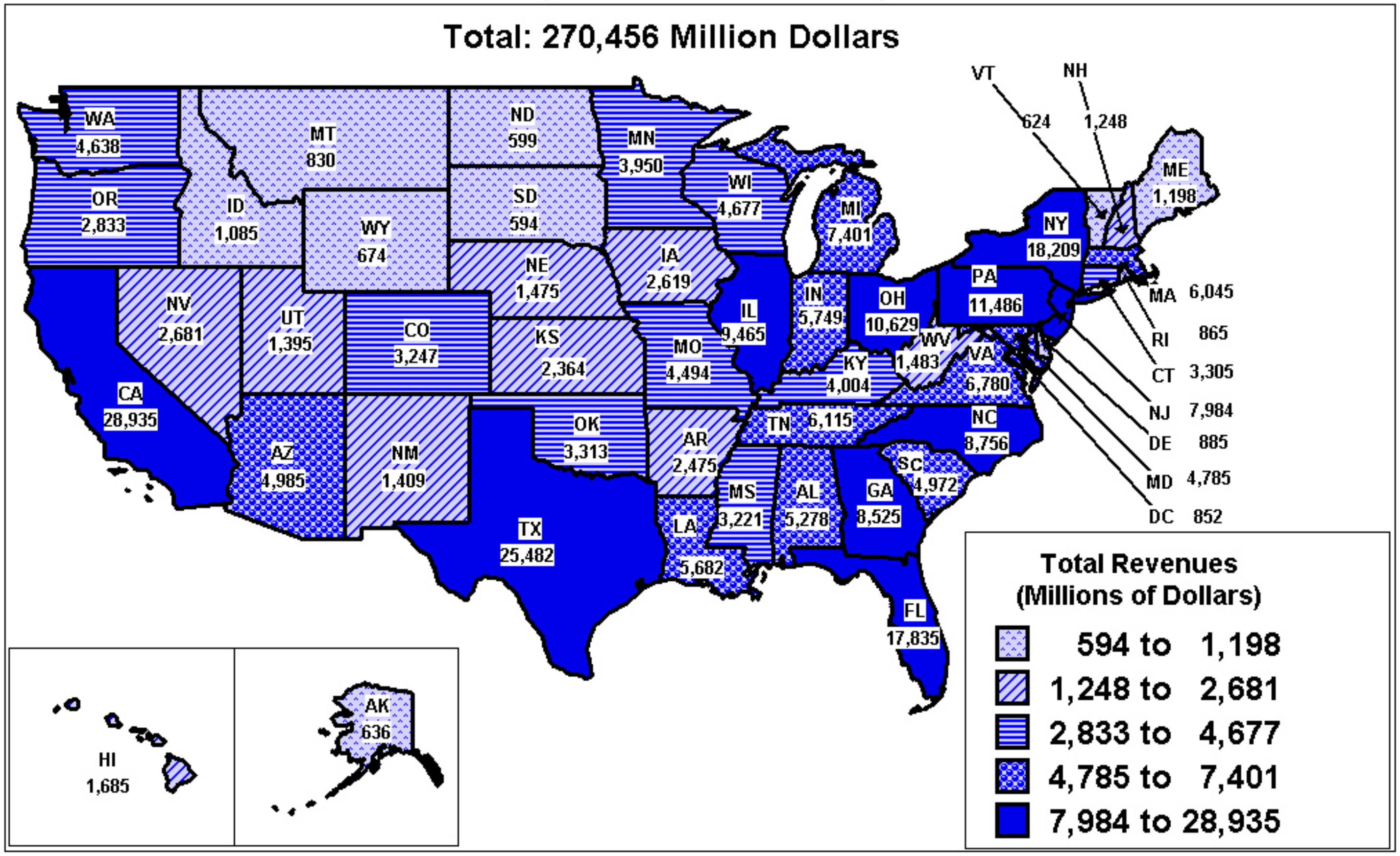
[3] From 1996 to 1999, revenue estimated based on retail sales reported on the Form EIA-861.

NA = Not available.R = Revised.

Notes: • See Glossary reference for definitions. • 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 a rate schedule. • 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. • 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 Power Industry Total Revenues by State, 2004 (Millions of Dollars)



Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.

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, 1993 through 2004

(Cents per kilowatthour)

Period	Residential	Commercial	Industrial	Transportation[1]	Other[1]	All Sectors
Total Electric Industry						
1993	8.32	7.74	4.85	NA	6.88	6.93
1994	8.38	7.73	4.77	NA	6.84	6.91
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	8.63[R]	7.95[R]	4.98[R]	NA	7.44[R]	7.31[R]
2002	8.46	7.90[R]	4.91[R]	NA	6.75[R]	7.22[R]
2003	8.70	8.00[R]	5.12[R]	7.55[R]	NA	7.42
2004	8.97	8.16	5.27	7.13	NA	7.62
Full-Service Providers[2]						
1993	8.32	7.74	4.85	NA	6.88	6.93
1994	8.38	7.73	4.77	NA	6.84	6.91
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	8.57[R]	7.84[R]	4.90[R]	NA	7.30[R]	7.23
2002	8.34	7.68[R]	4.74	NA	6.62[R]	7.06[R]
2003	8.62	7.79[R]	4.97[R]	6.82[R]	NA	7.30
2004	8.85	7.91	5.10	7.33	NA	7.47
Energy-Only Providers[3]						
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
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	7.67[R]	7.27[R]	5.55[R]	NA	7.44[R]	6.91[R]
2002	7.32[R]	6.58[R]	5.31[R]	NA	4.89[R]	6.27[R]
2003	6.71[R]	6.38[R]	4.84[R]	6.18[R]	NA	5.85[R]
2004	7.61	6.58	5.06	5.01	NA	6.21
Delivery-Only Service						
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	--	--	--	--	--	--
2001	3.20	2.31	1.28	--	1.44	2.18
2002	5.73	3.92	2.27	--	5.50	3.75
2003	5.10	3.75	1.84	2.07	--	3.20
2004	5.09	3.54	1.93	1.97	NA	3.21

[1] 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.

[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."

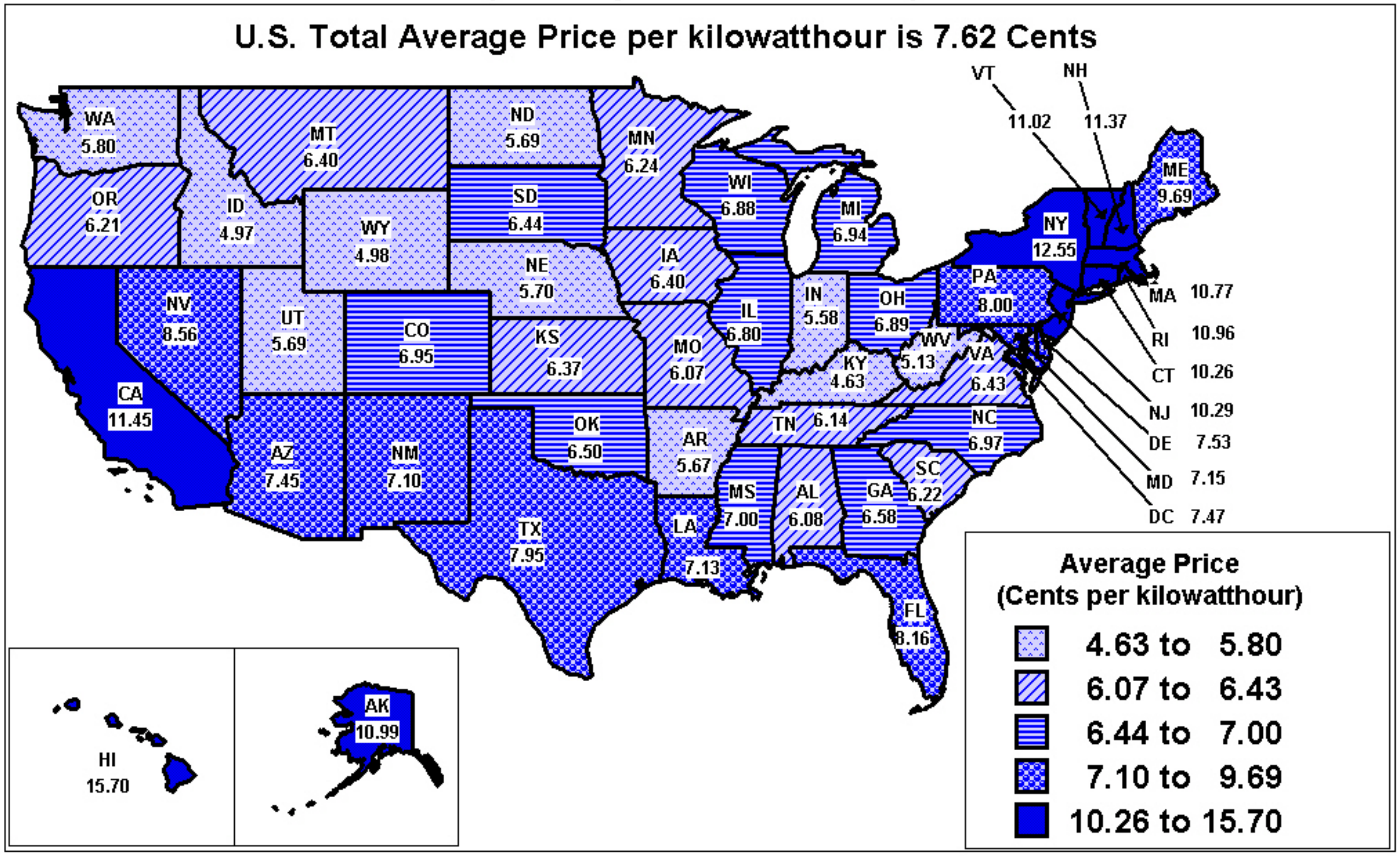
[3] From 1996 to 1999, average revenue estimated based on retail sales reported on the Form EIA-861.

NA = Not available.R = Revised.

Notes: • See Glossary reference for definitions. • 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.

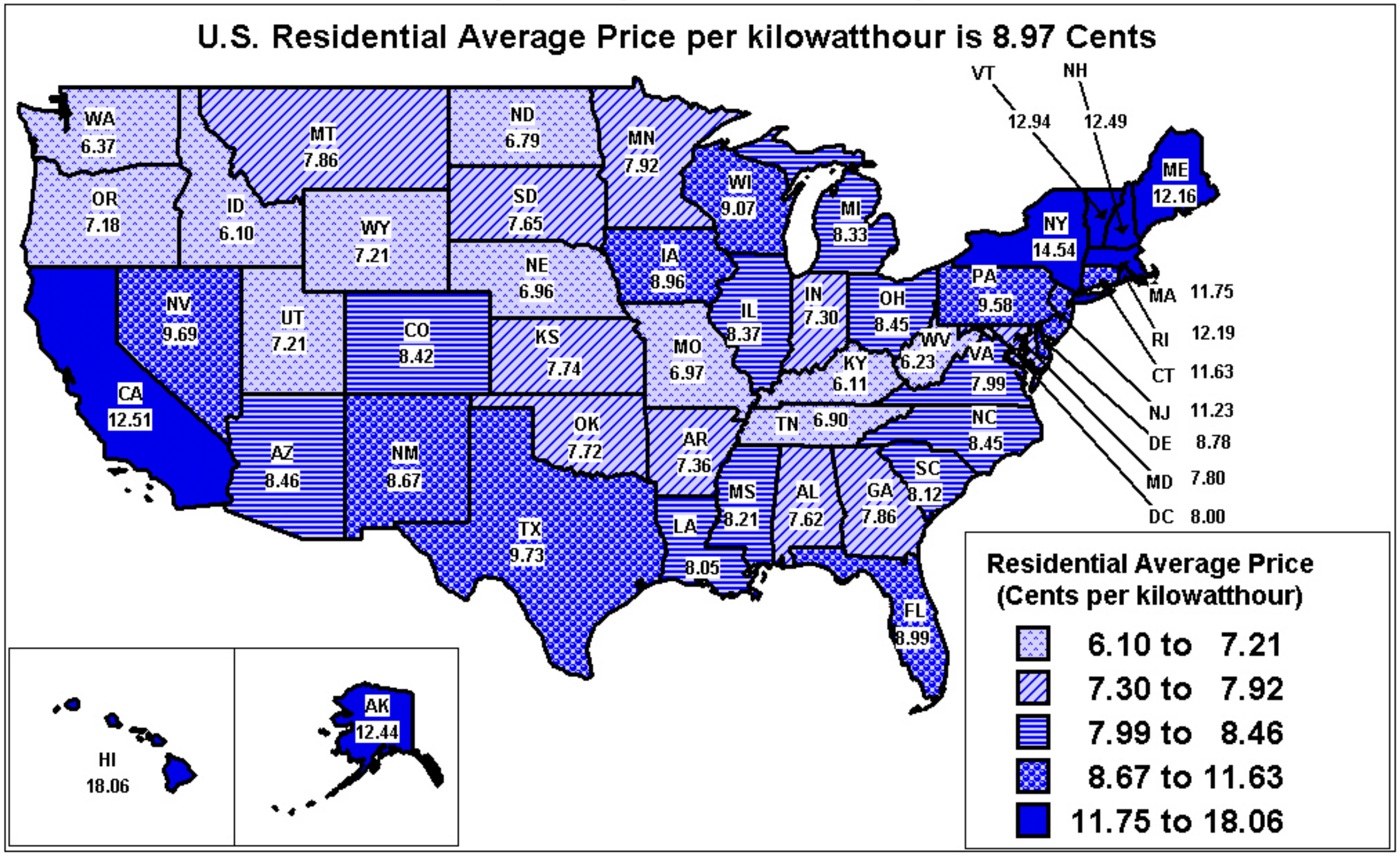
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.4 U.S. Electric Power Industry
Average Retail Price of Electricity by State, 2004
(Cents per kilowatthour)



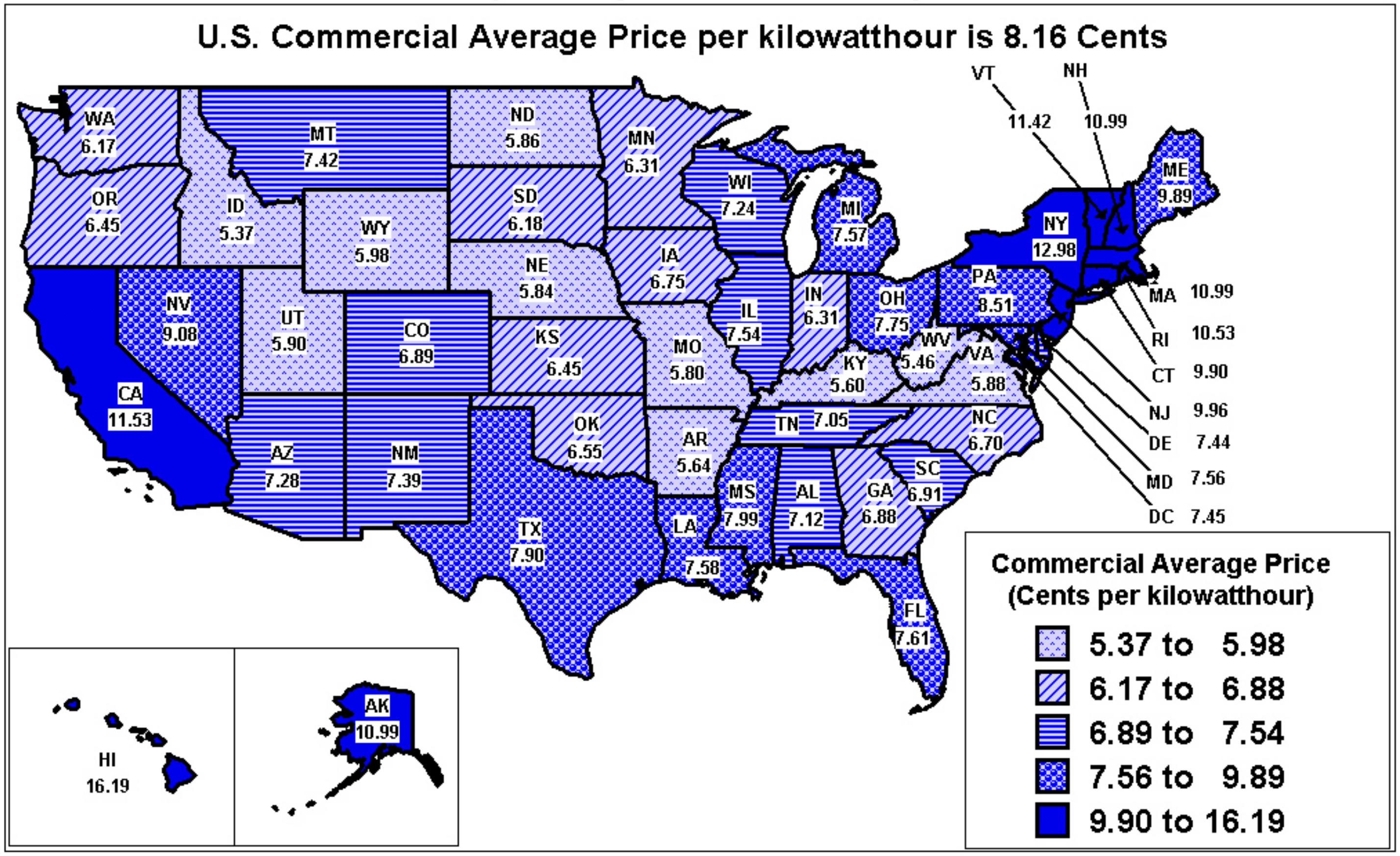
Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.5 U.S. Electric Industry Residential Average Retail Price of Electricity by State, 2004 (Cents per kilowatthour)



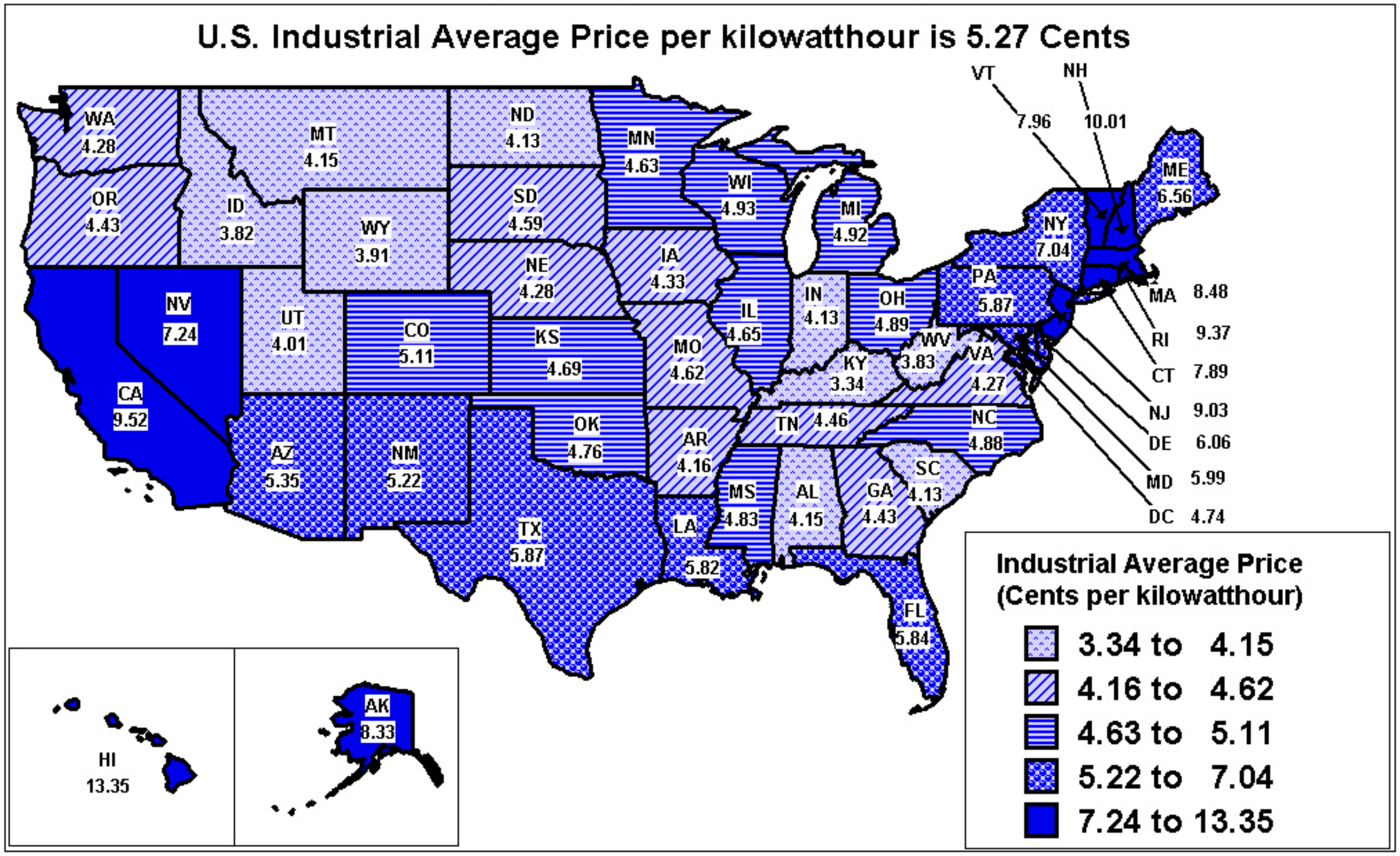
Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.6 U.S. Electric Industry Commercial Average Retail Price of Electricity by State, 2004
(Cents per kilowatthour)



Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.7 U.S. Electric Industry Industrial Average Retail Price of Electricity by State, 2004 (Cents per kilowatthour)



Note: Figure information is shown by 5 groupings of 10 States and The District of Columbia. The presented range moves from the values for the lowest 10 States to the top 10 States.
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, 1993 through 2004

(Million Dollars)

Description	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Utility Operating Revenues	**240,318**	**226,227**	**219,389**	**267,525**	**235,336**	**214,160**	**218,175**	**215,083**	**207,459**	**199,967**	**196,282**	**193,638**
Electric Utility	213,539	202,369	200,135	244,219	214,707	197,578	201,970	195,898	188,901	183,655	179,307	176,354
Other Utility	26,779	23,858	19,254	23,306	20,630	16,583	16,205	19,185	18,558	16,312	16,974	17,283
Utility Operating Expenses	**207,161**	**197,459**	**188,745**	**235,198**	**210,324**	**182,258**	**186,498**	**182,796**	**173,920**	**165,321**	**164,207**	**161,908**
Electric Utility	182,337	175,473	171,291	213,733	191,329	167,266	171,689	165,443	156,938	150,599	148,663	146,118
Operation	131,962	122,723	116,374	159,929	132,662	108,461	110,759	104,337	97,207	91,881	93,108	91,328
Production	104,287	96,181	90,649	136,089	107,352	83,555	85,956	80,153	73,437	68,983	69,269	68,781
Cost of Fuel	28,678	26,476	24,132	29,490	32,555	29,826	31,252	31,861	30,706	29,122	30,108	31,214
Purchased Power	67,354	62,173	58,828	98,231	61,969	43,258	42,612	37,991	32,987	29,981	29,213	27,716
Other	8,256	7,532	7,688	8,368	12,828	10,470	12,092	10,301	9,744	9,880	9,948	9,851
Transmission	4,519	3,585	3,494	2,365	2,699	2,423	2,197	1,915	1,503	1,425	1,361	1,354
Distribution	3,301	3,185	3,113	3,217	3,115	2,956	2,804	2,700	2,604	2,561	2,581	2,595
Customer Accounts	4,087	4,180	4,165	4,434	4,246	4,195	4,021	3,767	3,848	3,613	3,546	3,418
Customer Service	2,012	1,893	1,821	1,856	1,839	1,889	1,955	1,917	1,920	1,922	1,956	1,852
Sales	238	234	261	282	403	492	514	501	435	348	232	203
Administrative and General	13,519	13,466	12,872	11,686	13,009	12,951	13,311	13,384	13,458	13,028	14,163	13,124
Maintenance	11,774	11,141	10,843	11,167	12,185	12,276	12,486	12,368	12,050	11,767	12,022	12,447
Depreciation	16,373	16,962	17,319	20,845	22,761	23,968	24,122	23,072	21,194	19,885	18,679	18,099
Taxes and Other	22,228	24,648	26,755	21,792	23,721	22,561	24,322	25,667	26,488	27,065	24,854	24,244
Other Utility	24,823	21,986	17,454	21,465	18,995	14,992	14,809	17,353	16,983	14,722	15,544	15,790
Net Utility Operating Income	**33,158**	**28,768**	**30,644**	**32,327**	**25,012**	**31,902**	**31,677**	**32,286**	**33,539**	**34,646**	**32,074**	**31,730**

Note: 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 Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1993 through 2004

(Mills per Kilowatthour)

Plant Type	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Operation												
Nuclear	8.30	8.86	8.54	8.30	8.41	8.93	9.98	11.02	9.47	9.43	9.79	10.20
Fossil Steam	2.68	2.50	2.54	2.40	2.31	2.21	2.17	2.22	2.25	2.38	2.32	2.37
Hydroelectric[1]	5.05	4.50	5.07	5.79	4.74	4.17	3.85	3.29	3.87	3.69	4.53	3.82
Gas Turbine and Small Scale[2]	2.73	2.76	2.72	3.15	4.57	5.16	3.85	4.43	5.08	3.57	4.58	6.47
Maintenance												
Nuclear	5.38	5.23	5.04	5.01	4.93	5.13	5.79	6.90	5.68	5.21	5.20	5.73
Fossil Steam	2.96	2.73	2.68	2.61	2.45	2.38	2.41	2.43	2.49	2.65	2.82	2.96
Hydroelectric[1]	3.64	3.01	3.58	3.97	2.99	2.60	2.00	2.49	2.08	2.19	2.90	2.65
Gas Turbine and Small Scale[2]	2.16	2.26	2.38	3.33	3.50	4.80	3.43	3.43	4.98	4.28	5.39	7.52
Fuel												
Nuclear	4.58	4.60	4.60	4.67	4.95	5.17	5.39	5.42	5.50	5.75	5.87	5.88
Fossil Steam	18.21	17.35	16.11	18.13	17.69	15.62	15.94	16.80	16.51	16.07	16.67	17.65
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small Scale[2]	45.20	43.91	31.82	43.56	39.19	28.72	23.02	24.94	30.58	20.83	22.19	26.39
Total												
Nuclear	18.26	18.69	18.18	17.98	18.28	19.23	21.16	23.33	20.65	20.39	20.86	21.80
Fossil Steam	23.85	22.59	21.32	23.14	22.44	20.22	20.52	21.45	21.25	21.11	21.80	22.97
Hydroelectric[1]	8.69	7.51	8.65	9.76	7.73	6.77	5.86	5.78	5.95	5.89	7.43	6.47
Gas Turbine and Small Scale[2]	50.10	48.93	36.93	50.04	47.26	38.68	30.30	32.80	40.64	28.67	32.16	40.38

[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), 1993 through 2004
(Million Dollars)

Description	2004[1]	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Operating Revenue - Electric	**NA**	**33,906**	**32,776**	**38,028**	**31,843**	**26,767**	**26,155**	**25,397**	**24,207**	**23,473**	**23,267**	**22,522**
Operating Expenses - Electric	**NA**	**29,637**	**28,638**	**32,789**	**26,244**	**21,274**	**20,880**	**20,425**	**19,084**	**18,959**	**18,649**	**18,162**
Operation Including Fuel	**NA**	**22,642**	**21,731**	**25,922**	**19,575**	**15,386**	**15,120**	**14,917**	**13,768**	**13,653**	**13,578**	**13,242**
Production	NA	17,948	17,176	21,764	15,742	11,923	11,608	11,481	11,080	10,385	10,445	10,254
Transmission	NA	872	858	785	781	732	773	725	344	628	610	580
Distribution	NA	696	680	605	574	516	603	538	497	426	430	408
Customer Accounts	NA	582	537	600	507	415	390	390	365	323	317	315
Customer Service	NA	280	315	263	211	160	127	133	103	102	104	94
Sales	NA	84	74	73	66	49	51	46	18	20	22	17
Administrative and General	NA	2,180	2,090	1,832	1,695	1,591	1,567	1,602	1,360	1,769	1,651	1,573
Maintenance	**NA**	**2,086**	**1,926**	**1,904**	**1,815**	**1,686**	**1,631**	**1,609**	**1,638**	**1,575**	**1,584**	**1,565**
Depreciation and Amortization	**NA**	**3,844**	**3,907**	**4,009**	**3,919**	**3,505**	**3,459**	**3,239**	**3,160**	**2,934**	**2,721**	**2,596**
Taxes and Tax Equivalents	**NA**	**1,066**	**1,074**	**954**	**936**	**697**	**670**	**660**	**662**	**797**	**766**	**759**
Net Electric Operating Income	**NA**	**4,268**	**4,138**	**5,238**	**5,598**	**5,493**	**5,275**	**4,972**	**5,123**	**4,514**	**4,618**	**4,360**

[1] In 2004, Form EIA-412 has been suspended until further notice.

NA = Not available.

Notes: • Totals may not equal sum of components because of independent rounding. • The 1998-2003 data represent those utilities meeting a threshold of 150 million kilowatthours sales to ultimate customers and/or 150 million kilowatthours of sales for resale for the two previous years. The 1993-1997 data represent those utilities meeting a threshold of 120 million kilowatthours sales to ultimate customers and/or 120 million kilowatthours of sales for resale for the two previous years.

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), 1993 through 2004
(Million Dollars)

Description	2004[1]	2003[2]	2002[2]	2001[2]	2000	1999	1998	1997	1996	1995	1994	1993
Operating Revenue - Electric	**NA**	**12,454**	**11,546**	**10,417**	**9,904**	**9,354**	**8,790**	**8,586**	**8,582**	**8,435**	**7,996**	**7,523**
Operating Expenses - Electric	**NA**	**11,481**	**10,703**	**9,820**	**9,355**	**8,737**	**8,245**	**8,033**	**8,123**	**7,979**	**7,567**	**7,063**
Operation Including Fuel	**NA**	**10,095**	**9,439**	**8,864**	**8,424**	**7,874**	**7,437**	**7,117**	**7,359**	**7,173**	**6,858**	**6,425**
Production	NA	8,865	8,311	7,863	7,486	7,015	6,661	6,240	6,578	6,422	6,185	5,761
Transmission	NA	105	93	61	64	48	44	57	51	35	34	34
Distribution	NA	348	320	311	280	261	230	304	234	204	190	189
Customer Accounts	NA	172	163	164	155	143	130	139	141	125	119	117
Customer Service	NA	31	39	26	22	22	21	16	18	18	17	17
Sales	NA	11	10	15	16	14	9	13	12	10	10	9
Administrative and General	NA	562	504	423	402	371	342	348	325	358	303	298
Maintenance	**NA**	**418**	**389**	**304**	**286**	**272**	**263**	**338**	**244**	**250**	**234**	**207**
Depreciation and Amortization	**NA**	**711**	**631**	**405**	**394**	**369**	**330**	**354**	**322**	**313**	**274**	**257**
Taxes and Tax Equivalents	**NA**	**257**	**244**	**247**	**251**	**223**	**215**	**225**	**206**	**244**	**201**	**175**
Net Electric Operating Income	**NA**	**974**	**843**	**597**	**549**	**617**	**545**	**552**	**459**	**457**	**429**	**460**

[1] In 2004, Form EIA-412 has been suspended until further notice.

[2] For 2001 - 2003, California Department of Water Resources - Electric Energy Fund data were included in these statistics. 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 were $5,501,000,000 with purchased power costs of $12,055,000,000. Their 2002 revenue collected were $4,210,000,000 with purchased power costs of $3,827,749,811. Their 2003 revenue collected were $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.

NA = Not available.

Notes: • Totals may not equal sum of components because of independent rounding. • The 1998-2003 data represent those utilities meeting a threshold of 150 million kilowatthours sales to ultimate customers and/or 150 million kilowatthours of sales for resale for the two previous years. The 1993-1997 data represent those utilities meeting a threshold of 120 million kilowatthours sales to ultimate customers and/or 120 million kilowatthours of sales for resale for the two previous years.

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, 1993 through 2004
(Million Dollars)

Description	2004[1]	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Operating Revenue - Electric	**NA**	**11,798**	**11,470**	**12,458**	**10,685**	**10,186**	**9,780**	**8,833**	**9,082**	**8,743**	**8,552**	**8,141**
Operating Expenses - Electric	**NA**	**8,763**	**8,665**	**10,013**	**8,139**	**7,775**	**7,099**	**5,999**	**6,390**	**6,162**	**6,303**	**6,056**
Operation Including Fuel	**NA**	**6,498**	**6,419**	**7,388**	**5,873**	**5,412**	**5,184**	**4,073**	**4,514**	**4,615**	**4,877**	**4,827**
Production	NA	5,175	5,236	6,247	5,497	4,890	4,735	3,686	4,109	4,219	4,464	4,272
Transmission	NA	307	244	354	332	349	323	327	328	290	304	319
Distribution	NA	1	1	1	2	2	2	1	1	2	2	2
Customer Accounts	NA	4	10	16	6	1	1	1	3	2	4	4
Customer Service	NA	63	60	60	48	50	51	42	46	29	28	27
Sales	NA	20	6	6	10	28	14	13	7	41	9	6
Administrative and General	NA	927	862	705	467	528	535	444	451	431	442	578
Maintenance	**NA**	**600**	**566**	**521**	**488**	**436**	**476**	**441**	**432**	**398**	**377**	**381**
Depreciation and Amortization	**NA**	**1,335**	**1,351**	**1,790**	**1,471**	**1,623**	**1,175**	**1,214**	**1,187**	**896**	**746**	**611**
Taxes and Tax Equivalents	**NA**	**329**	**328**	**315**	**308**	**304**	**264**	**272**	**256**	**252**	**56**	**237**
Net Electric Operating Income	**NA**	**3,035**	**2,805**	**2,445**	**2,546**	**2,411**	**2,681**	**2,834**	**2,692**	**2,581**	**2,249**	**2,085**

[1] In 2004, Form EIA-412 has been suspended until further notice.
NA = Not available.
Note: 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, 1993 through 2004
(Million Dollars)

Description	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Operating Revenue - Electric	**30,650**	**29,228**	**27,458**	**26,458**	**25,629**	**23,824**	**23,988**	**23,321**	**24,424**	**24,609**	**23,777**	**24,873**
Operation and Maintenance Expenses	**27,828**	**26,361**	**24,561**	**23,763**	**22,982**	**21,283**	**21,223**	**20,715**	**23,149**	**21,741**	**20,993**	**21,675**
Operation Including Fuel	**25,420**	**24,076**	**22,383**	**21,703**	**20,942**	**19,336**	**19,280**	**18,405**	**20,748**	**19,334**	**18,650**	**19,292**
Production	20,752	19,559	18,143	17,714	17,080	15,706	15,683	15,105	17,422	15,907	15,471	16,101
Transmission	665	637	579	524	525	466	452	339	372	366	322	336
Distribution	1,860	1,787	1,681	1,589	1,530	1,451	1,440	1,134	1,133	1,127	1,053	1,044
Customer Accounts	595	579	545	532	487	455	446	382	375	383	374	386
Customer Service	141	140	136	119	133	132	132	118	118	112	105	101
Sales	80	79	79	88	82	81	77	61	72	72	61	57
Administrative and General	1,327	1,295	1,219	1,137	1,104	1,045	1,050	1,266	1,257	1,367	1,265	1,265
Depreciation and Amortization	**2,182**	**2,076**	**1,992**	**1,895**	**1,820**	**1,747**	**1,732**	**1,727**	**1,787**	**1,778**	**1,742**	**1,768**
Taxes and Tax Equivalents	**226**	**209**	**186**	**164**	**220**	**200**	**211**	**583**	**614**	**628**	**601**	**616**
Net Electric Operating Income	**2,822**	**2,867**	**2,897**	**2,696**	**2,647**	**2,541**	**2,764**	**2,606**	**2,872**	**2,868**	**2,784**	**3,197**

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, 1993 through 2004
(Megawatts)

Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Total Actual Peak Load Reduction[1]	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**	**23,069**
Energy Efficiency	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,326	14,243	13,212	11,662	10,368
Load Management	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,347	13,340	12,701

[1] Represents 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, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.

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 9.2. Demand-Side Management Program Annual Effects by Program Category, 1993 through 2004

Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
	Annual Effects – Energy Efficiency											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243	13,212	11,662	10,368
Energy Savings (Thousand MWh)	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119
	Annual Effects – Load Management											
Large Utilities[1]												
Actual Peak Load Reduction (MW)	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,349	13,339	12,701
Potential Peak Load Reductions (MW)	20,998	25,290	26,888	27,730	28,496	30,118	27,840	27,911	34,101	33,817	31,255	29,140
Energy Savings (Thousand MWh)	2,047	2,020	1,790	990[R]	875	872	392	953	1,989	2,093	2,763	4,175

[1] Represents 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, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.

[2] Represents the actual reduction in annual peak load achieved by customers, at the time of annual peak load.

R = Revised.

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 9.3. Demand-Side Management Program Incremental Effects by Program Category, 1993 through 2004

Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
	Incremental Effects – Energy Efficiency											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	1,521	945	1,054	999	720	695	796	1,065	1,381	1,561	1,751	1,839
Energy Savings (Thousand MWh)	4,522	2,939	3,543	4,402	3,284	3,027	3,324	4,661	6,361	7,901	8,054	8,601
Small Utilities[3]												
Actual Peak Load Reduction (MW)[2]	204	90	49	20	25	22	12	12	2	7	9	9
Energy Savings (Thousand MWh)	10	8	192	8	8	8	37	10	7	16	11	12
	Incremental Effects – Load Management											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	907	1,084	1,160	1,297	919	1,568	1,821	1,261	5,027	3,039	1,418	2,809
Potential Peak Load Reductions (MW)[4]	2,622	1,981	2,655	2,448	2,439	6,457	2,832	2,475	2,309	4,930	5,153	5,298
Energy Savings (Thousand MWh)	2	29	65	79[R]	63	67	37	171	482	321	178	508
Small Utilities[3]												
Actual Peak Load Reduction (MW)[2]	242	81	54	45	137	54	124	130	50	29	56	110
Potential Peak Load Reductions (MW)[4]	422	131	76	177	190	84	160	183	90	41	81	291
Energy Savings (Thousand MWh)	4	4	2	4	9	2	7	19	6	3	8	11

[1] Represents 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, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.

[2] Represents the actual reduction in annual peak load achieved by customers, at the time of annual peak load.

[3] Refers to electric utilities with annual sales to ultimate customers or sales for resale less than 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.

[4] Represents the potential peak load reduction as a result of load management, and also includes the actual peak load reduction achieved by energy efficiency programs.

R = Revised.

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 9.4. Demand-Side Management Program Annual Effects by Sector, 1993 through 2004

Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Actual Peak Load Reductions[1] (MW)												
Large Utilities[2]												
Residential	8,870	9,431	9,137	9,619	9,446	9,976	9,327	10,799	11,471	10,930	9,638	8,851
Commercial	7,194	6,774	6,839	8,210	6,987	7,777	9,482	8,174	8,678	8,057	6,927	7,541
Industrial	7,454	6,594	6,500	6,553	6,141	6,360	7,927	5,812	9,083	10,033	7,977	6,270
Transportation	14	105	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	460	573	327	2,342	495	498	661	545	460	407
Total	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**	**23,069**
Potential Peak Load Reductions[3] (MW)												
Large Utilities[2]												
Residential	11,967	12,525	12,072	12,274	12,970	12,812	13,022	16,662	14,697	14,047	13,851	12,868
Commercial	9,624	8,943	9,298	10,469	9,114	8,868	12,210	12,896	12,452	11,495	9,915	11,821
Industrial	13,665	17,298	18,321	17,344	18,775	17,237	15,512	11,035	20,275	20,715	18,271	13,957
Transportation	14	105	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	617	670	510	4,653	686	644	921	772	881	862
Total	**35,270**	**38,871**	**40,308**	**40,757**	**41,369**	**43,570**	**41,430**	**41,237**	**48,344**	**47,029**	**42,917**	**39,508**
Energy Savings (Thousand MWh)												
Large Utilities[2]												
Residential	17,763	13,469	15,438	16,027	16,287	16,263	16,564	17,830	20,585	20,253	21,028	19,241
Commercial	24,624	25,089	24,391	24,217	25,660	23,375	25,125	27,898	29,186	26,187	21,773	16,567
Industrial	12,273	11,156	11,339	10,487[R]	9,160	8,156	3,347	8,684	10,493	9,620	8,568	8,644
Transportation	51	551	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	2,907	3,206	2,593	2,770	831	1,694	1,578	1,360	1,114	842
Total	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**	**45,294**

[1] Represents 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, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.

[2] Refers to electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.

[3] Represents the potential peak load reduction as a result of load management, and also includes the actual peak load reduction achieved by energy efficiency programs.

NA = Not available.R = Revised.

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 9.5. Demand-Side Management Program Incremental Effects by Sector, 1993 through 2004

Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Actual Peak Load Reductions[1] (MW)												
Large Utilities[2]												
Residential	1,361	640	895	790	572	605	599	743	792	860	1,083	1,147
Commercial	560	528	527	742	515	684	1176	699	935	1176	1,244	1,427
Industrial	507	849	680	640	502	929	799	836	1,870	2,426	785	2,014
Transportation	0	12	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	112	124	50	45	43	48	93	139	57	61
Total	**2,428**	**2,029**	**2,214**	**2,296**	**1,640**	**2,263**	**2,617**	**2,326**	**3,690**	**4,601**	**3,169**	**4,648**
Small Utilities[3]												
Residential	280	88	48	32	37	27	35	40	30	20	27	76
Commercial	126	58	41	15	37	22	34	21	9	10	7	35
Industrial	40	25	12	16	62	7	56	61	8	4	24	47
Transportation	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	0	0	26	19	10	20	5	2	6	28
Total	**446**	**171**	**101**	**63**	**162**	**76**	**136**	**142**	**52**	**36**	**65**	**185**
U.S. Total	**2,874**	**2,200**	**2,317**	**2,361**	**1,802**	**2,339**	**2,753**	**2,468**	**3,742**	**4,637**	**3,234**	**4,833**
Potential Peak Load Reductions[4] (MW)												
Large Utilities[2]												
Residential	1,680	752	1,311	900	699	753	751	960	950	1,231	1,467	NA
Commercial	894	602	751	1,115	565	718	1,863	853	1,512	1,697	2,115	NA
Industrial	1,569	1,551	1,506	1,277	1,815	5,612	1,438	1,669	3,800	3,368	1,997	NA
Transportation	0	21	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	141	155	79	68	76	58	146	195	326	NA
Total	**4,143**	**2,926**	**3,709**	**3,447**	**3,159**	**7,151**	**3,628**	**3,540**	**6,408**	**6,491**	**5,905**	**7,157**
Small Utilities[3]												
Residential	395	116	64	158	55	41	49	59	46	27	38	NA
Commercial	154	73	43	19	51	25	41	35	17	13	12	NA
Industrial	77	32	15	18	64	9	70	72	16	6	31	NA
Transportation	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	3	2	44	31	12	30	13	2	8	NA
Total	**626**	**221**	**125**	**197**	**215**	**106**	**172**	**196**	**92**	**48**	**89**	**300**
U.S. Total	**4,769**	**3,147**	**3,834**	**3,644**	**3,374**	**7,257**	**3,800**	**3,736**	**6,500**	**6,539**	**5,994**	**7,457**
Energy Savings (Thousand MWh)												
Large Utilities[2]												
Residential	1,842	868	1,203	1,365	856	990	909	1,055	1,179	1,630	2,194	2,780
Commercial	1,815	1,356	1,583	1,867	1,780	1,502	1,703	2,382	3,537	4,594	4,449	4,557
Industrial	867	732	706	872[R]	547	475	645	1,059	1,787	1,678	1,325	1,518
Transportation	0	12	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	116	376	164	127	104	336	341	320	262	125
Total	**4,524**	**2,968**	**3,608**	**4,481**	**3,347**	**3,094**	**3,361**	**4,832**	**6,844**	**8,222**	**8,230**	**8,980**
Small Utilities[3]												
Residential	6	7	45	5	9	4	8	10	7	9	13	13
Commercial	7	5	148	3	4	3	6	3	3	5	3	4
Industrial	2	1	2	2	1	1	3	8	2	5	1	3
Transportation	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	*	3	3	1	1	7	1	2	1	2
Total	**14**	**13**	**194**	**13**	**17**	**9**	**18**	**28**	**13**	**21**	**18**	**22**
U.S. Total	**4,539**	**2,981**	**3,802**	**4,492**	**3,364**	**3,103**	**3,379**	**4,860**	**6,857**	**8,243**	**8,248**	**9,002**

[1] Represents the actual reduction in annual peak load achieved by customers, at the time of annual peak load.
[2] Refers to electric utilities with sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.
[3] Refers to electric utilities with sales to ultimate customers or sales for resale less than 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.
[4] Represents the potential peak load reduction as a result of load management, and also includes the actual peak load reduction achieved by energy efficiency programs.

* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is "1" and values under 0.5 are shown as "*".)

NA = Not available.R = Revised.

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 9.6. Demand-Side Management Program Energy Savings, 1993 through 2004
(Thousand megawatthours)

Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Total Energy Savings[1]	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**	**45,294**
Energy Efficiency	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119
Load Management	2,047	2,020	1,790	990[R]	875	872	392	953	1,989	2,093	2,763	4,175

[1] Refers to electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2004 and 120 million kilowatthours in 1993-1997.

R = Revised.

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, 1993 through 2004
(Thousand Dollars)

Item	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Direct Cost[1]	**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**	**2,254,059**	**2,289,267**
Energy Efficiency	910,115	807,403	1,007,323	1,097,504	938,666	820,108	766,384	892,468	1,051,922	1,408,542	1,592,125	1,607,952
Load Management	515,057	352,137	413,614	358,098	445,566	430,581	466,634	454,777	571,666	596,400	661,934	681,315
Indirect Cost[2]	**132,294**	**137,670**	**204,600**	**174,684**	**180,669**	**172,955**	**187,902**	**288,775**	**278,609**	**416,342**	**461,598**	**454,266**
Total DSM Cost[3]	**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**	**2,715,657**	**2,743,533**

[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 utility cost for the year. Utility costs reflect the total cash expenditures for the year, in nominal dollars, that flow out to support demand-side management programs.

Notes: • Includes expenditures reported by large electric utilities, only. See the data files for DSM expenditures of small utilities (http://www.eia.doe.gov/cneaf/electricity/page/eia861.html). • 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 is 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.

Reliability of Data

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

Although no direct measurement of the biases due to nonsampling errors can be obtained, precautionary steps were taken in all phases of the frame development and data collection, processing, and tabulation processes, in an effort to minimize their influence. See the Data Processing and Data System Editing section for each EIA Form for an in-depth discussion of how the sampling and nonsampling errors are handled in each case.

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 should be 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.
- All monthly and quarterly survey data are first disseminated as preliminary. These data are revised only after the completion of the 12-month cycle of the data. No revisions are made to the published data before this unless significant errors are discovered that are brought to the attention of the Office Director by the responsible Division Director. In that case, determination as to whether the data should be revised is described in a later bullet.
- Weekly and monthly coal production data are first disseminated as estimates. These estimates are revised when quarterly data become available and later finalized when adjusted to conform to final annual production data.
- Any CNEAF data released as preliminary or estimated will be revised, if necessary, and disseminated as final at the same levels of aggregation in a future data product.
- After data are disseminated as final, further revisions will be considered if they make a difference of one percent or greater at the national level. Revisions for differences that do not meet the one percent or greater threshold will be brought to the attention of the Office Director for consideration if the responsible Division Director believes the proposed revision is significant. In either case, the proposed revision will be subject to the EIA revision policy concerning how it affects other EIA products.

- The stages of the data (e.g., preliminary, estimated, final, revised) will be so designated in table/figure titles, headers, or footnotes, or in the accompanying text.
- 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 CNEAF data revision procedures should be referenced in each data product release.

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. On a chapter basis, the status (preliminary versus final) of the data contained in the EPA follows:

- **Chapter 1, Generation and Useful Thermal Output** Based on data from the Form EIA-906. All data are final.
- **Chapter 2, Capacity** Based on data from the Form EIA-860. All data are final.
- **Chapter 3, Demand, Capacity Resources, and Capacity Margins** Based on data from the Form EIA-411. All data are final.
- **Chapter 4, Fuel** Based on data from the Form EIA-906, EIA-920, EIA-423 and FERC Form 423. All data are final.
- **Chapter 5, Emissions** Based on data from the Form EIA-767, EIA-906, and EIA-920 and on data extracted from the U.S. Environmental protection Agency's Continuous Emission Monitoring System database. The emissions estimates for 2004 are preliminary.
- **Chapter 6, Trade** Based on data from the Form EIA-861 and on import/export data from the National Energy Board of Canada and the Office of Fuels Programs, Fossil Energy, Form FE-781R. All data are final.
- **Chapter 7, Retail Customers, Sales, and Revenues** Based on data on sales, revenue, and calculated average retail price of electricity from the Form EIA-861. All data are final.
- **Chapter 8, Revenue and Expense Statistics** Based on financial data from the Federal Energy Regulatory Commission Form 1, Form EIA-412, and Rural Utility Services Form 7 and Form 12. All data are final.
- **Chapter 9, Demand-Side Management** Based on data on demand-side management from the Form EIA-861. All data are final.

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;" [Suspended]
- 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;" and
- Form EIA-906, "Power Plant Report."
- 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:

- Fossil Energy Form FE-781R, "Annual Report of International Electric Export/Import Data;" (Department of Energy, Office of Emergency Planning Department of Energy, Office of Fuels Programs);
- Federal Energy Regulatory Commission (FERC) 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.

Form EIA-411

The Form EIA-411 is filed annually 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 present various North American Electric Reliability Council (NERC) regional council aggregate totals for their member electric utilities, with some nonmember information included.

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 returned to EIA for the reporting year 1996.

Data Processing and Data System Editing. The 10 North American Electric Reliability Councils file the Form EIA-411 annually on June 1. The 10 North American Electric Reliability Councils file a joint response through the NERC Headquarters annually on the Form EIA-411. The forms are compiled from data furnished by electricity generators (members, associates, and nonmembers) within the council areas.

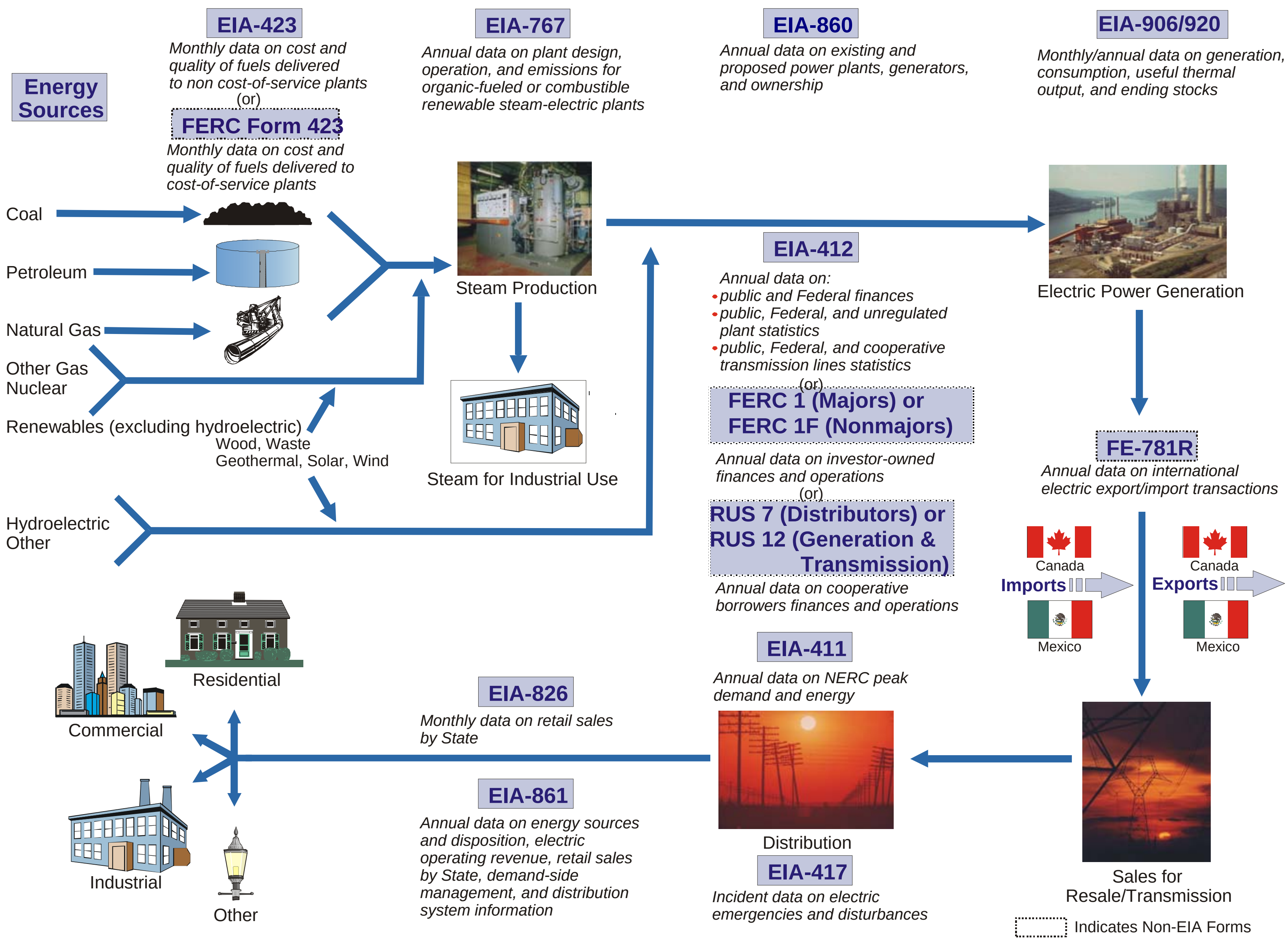
Confidentiality of the Data. Most of the data collected on the Form EIA-411 are not considered confidential. However, plant latitudes and longitudes and tested heat rate data are considered confidential and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45Federal Register 59812 (1980)).

Form EIA-412 [Suspended]

The Form EIA-412 is a restricted-universe census (no companies that fall below a pre-determined threshold are 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," must submit the Form EIA-412. 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.

The 1992-1997 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.

EIA Electric Industry Data Collection



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.

Data Processing and Data System Editing. The Form EIA-412 is made available on EIA's Internet Data Collection system in January to collect data as of the end of the preceding calendar year. The completed surveys are due to EIA on or before April 30. Non-response follow-up procedures are used to attain 100-percent response. Initial edit checks of the data are performed through the EIA's Internet Data Collection System (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 office or by further information obtained from a telephone call to the respondent company.

Confidentiality of the Data. The nonutility data collected on "Electric Generating Plant Statistics" for "Cost of Plant" and "Production Expenses," plant fuel cost data, of this survey are considered confidential and will not be made available to the public.

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.

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.

Data Processing and Data System Editing. The Form EIA-423 survey respondents are required to submit their data by the 45th calendar day following the close of the month. During 2003 a process was established to allow electronic submission of these data, i.e., the respondents enter their data directly into a computerized database. Anomalous data are identified via range checks, comparisons with historical data, and consistency checks (for example, whether the amount of fuel received is consistent with the amount of fuel consumption reported on a separate EIA report). Most of these edit checks are performed on-line as the data are provided. Others are performed at the end of the cycle by running batch edit reports to identify those not addressed on-line.

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.

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, $\sum$, represents the sum of all facilities in that geographic region.

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

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

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

For each of the above fossil fuels:

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

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

A_i = average heat content for receipts at facility i;

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

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

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

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

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

A_i average heat content for receipts at facility i;

and C_i = cost in cents per million Btu for facility i.

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

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

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

A_i = average heat content for receipts at facility i;

and, C_i = cost in cents per million Btu for facility i.

Confidentiality of the Data. Plant fuel cost data collected on the survey are considered confidential and will not be made available to the public. 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 processes the data through edits and each month 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 with 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).

The associated fuel quality and cost information for each facility was estimated using the State weighted average for the electric power industry for the year (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 year were used.

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.

Confidentiality of the Data. Data collected on FERC Form 423 are not considered to be confidential.

Form EIA-767

The Form EIA-767 is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, air pollution control equipment, and stack characteristics. Data are 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 is filed by approximately 800 power plants with a nameplate capacity of 100 or more megawatts. The Form EIA-767 is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data). 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 oxide, 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. Respondents for plants with capacity between 10 and 100 megawatts, complete Schedules 1, 2, 4 (Part A, D, and E), 5, 7 and 8 (Part A and B). Schedule 10, "Footnote," is required where applicable.

Data Processing and Data System Editing. The Form EIA-767 is made available on EIA's Internet Data Collection system in January to collect data as of the end of the preceding calendar year. The completed forms are to be submitted to the EIA by April 30. Equipment design data for each respondent are preprinted from the applicable database. Respondents are instructed to verify all preprinted data and to supply missing data. The data are edited by respondents when entered into the interactive on-line system. Internal edit checks are performed to verify that current data are comparable between schedules and data reported the previous year. Edit checks are also performed by EIA to compare data reported on the Form EIA-860, "Annual Electric Generator Report", Form EIA-906, "Power Plant Report", and Form EIA-920, "Combined Heat and Power Plant Report". The data submitted by hard copies are manually reviewed before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process.

Confidentiality of the Data. The plant latitude and longitude data collected on the Form EIA-767 are considered confidential. The data are handled by EIA consistent with EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45Federal Register 59812 (1980)).

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 generator unit level.

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 - Non-utility." 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.

Data Processing and Data System Editing. The Form EIA-860 data are collected primarily through the IDC. Data are collected for plant status as of January 1. Edit checks are performed to verify that current data total across and between schedules, are comparable to data reported the previous year, and are consistent with industry norms for comparable facilities. Additional quality assurance reports are run to identify errors. As a result of the editing process, respondents may be contacted to obtain correction or clarification of reported data and to obtain missing data.

Of the 16,770 existing generators in the 2004 Form EIA-860 frame, imputation was performed for 330 generators. These 330 generators account for 0.2 percent of the existing 2004 electric generating capacity. Imputation was performed at the respondent/plant/generator levels, using the preliminary 2004 respondent data.

Confidentiality of the Data. The plant latitude and longitude, and tested heat rate data collected on the Form EIA-860 are considered confidential. The data 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 (1980) 59812).

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 3,400 respondents. About 3,200 are electric utilities, and the remainder are nontraditional entities such as independent power producers 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.

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 2004, 54 respondents reported transportation data in 25 States.

California. As a consequence of unrecoverable high average wholesale power costs in California in 2000 and early 2001, the credit ratings of California's three major investor-owned utilities fell below investment grade by early 2001.

The rapid and dramatic decline in the credit-worthiness of California's major investor-owned utilities virtually eliminated their ability through wholesale markets to meet the power requirements of their retail consumers. In response to the looming energy shortfall, the California State legislature authorized the California Department of Water Resources (CDWR), using its undamaged borrowing capability, to enter the wholesale markets on behalf of the California retail consumer effective on January 17, 2001, and for the period ending December 31, 2002. Also the California Public Utility Commission (CPUC) was required by statute to establish the procedures for facilitating the CDWR's participation in California retail sales, as well as retail revenue recovery mechanisms. CDWR's continued commitment to the California ratepayers is related to long-term contracts for resources that will last for years.

Energy provided by the CDWR was delivered by the major investor-owned utilities in California. For this reason, and by agreement with the CDWR, energy sales and associated revenue related to the CDWR's intervention in the crisis are identified as "Energy Only Providers."

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

Data Processing and Data System Editing. The Form EIA-861 is made available through the Internet Data Collection System in January of each year to collect data as of the end of the preceding calendar year. The data are edited by respondents when entered into the interactive on-line system. Internal edit checks are performed to verify that current data total across and between schedules, and are comparable to data reported the previous year. Edit checks are also performed to compare data reported on the Form EIA-861 and similar data reported on the Forms EIA-826. Respondents are telephoned to obtain clarification of reported data and to obtain missing data.

Data for the Form EIA-861 are collected at the owner level from all electric utilities in the United States, its territories, and Puerto Rico. Form EIA-861 data in this publication are for the United States only.

Imputation. This year, the *Electric Power Annual* (EPA) will report 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's historic total retail sales data series previously relied on the sum of bundled sales and those provided by power marketers and energy service providers. This new method was used because EIA concluded that the retail sales data reported by delivery utilities were more reliable than data reported by power marketers and ESPs. This methodological change also provides reporting which is consistent with the monthly retail sales data collected on Form EIA-826, "Monthly Electric Sales and Revenue with State Distributions Report," and reported (with imputation) in the *Electric Power Monthly* (EPM). Data for the years 2001 through 2003 have also been restated to reflect this method of developing retail sales, with a few exceptions noted below.

In 2003, the EIA made adjustments to retail sales volumes in 7 of the 18 deregulated States. Volumes reported by distribution utilities in those States generally exceeded those reported by power marketers and energy service providers (ESPs). The rapid entry and exit of power marketers and energy service providers in deregulated markets makes it difficult to maintain a survey frame that reflects full market participation. Because EIA concluded that power marketers and energy service providers were under-represented in the survey frame, EIA adjusted (increased) 2003 retail sales reported by those entities to balance the amount of sales reported by delivery utilities.

The methodological change we are introducing in this year's EPA, like the EPM, now relies on sales volumes and customer counts reported by distribution utilities, and adds only an incremental revenue value, representing missing sales assumed to be attributable to the ESPs that were under-represented in the survey frame. In some cases, adjustments were 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. Also for the first time, data for 2004 reflects 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 is drawn from Form EIA-826). Form EIA-826 is a monthly-stratified sample of approximately 450 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 2004, their data was 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. For 2004, the EPA reflects imputed retail sales volumes equivalent to only 8 billion kWh, or approximately 0.2 percent of the total reported retail sales volume.

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.

Confidentiality of the Data. Data collected on the Form EIA-861 are not considered to be confidential.

Form EIA-906

The Form EIA-906 is used to collect monthly plant-level data on generation, fuel consumption, stocks, and fuel heat content, from electric utilities and nonutilities from a model-based sample of approximately 206 electric utilities and 418 nonutilities. The form is also used to collect these statistics from the rest of the frame (i.e., all generators 1 MW or greater) on an annual basis.

Fuel consumption for combined heat and power facilities is apportioned between fuel for generation of electricity and fuel for production of useful thermal output, by assuming they are additive. Fuel usage for these facilities is assumed to have an efficiency of 80 percent. The consumption for useful thermal output is obtained by dividing the reported or estimated value for useful thermal output by 0.8. This value is then subtracted from total fuel consumption by facility to arrive at the fuel consumption to be associated with the generation of electricity

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 define 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. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

As of January 2004, combined heat and power plants that formerly reported on the Form EIA-906 began reporting on Form EIA-920. Prior to January 2004, fuel use for the production of electricity was imputed from the total fuel consumption and the useful thermal otuput reported by the facilities.

Data Processing and Data System Editing The Form EIA-906 data are collected primarily through the CNEAF Internet Data Collection System. Edit checks are performed to verify that current data are comparable to data reported the previous year or month, and are consistent with industry norms for comparable facilities. Additional quality assurance reports are run to identify errors. As a result of the editing process, respondents may be contacted to obtain correction or clarification of reported data and to obtain missing data.

The review of the Form EIA-906 filings for non-regulated facilities in 2001 uncovered widespread problems with the data reporting. The most prevalent problems were reported fuel consumption inconsistent with generation and, most significantly, incorrect reporting of useful thermal output (UTO) by combined heat and power (CHP) facilities.

UTO is the thermal output from a CHP facility applied to a production process other than electricity generation. Many facilities either misunderstood EIA's definition or did not meter internally such that they could easily estimate the UTO from CHP plants. This was an important problem in the data collection effort. If UTO is reported incorrectly, then the reported data cannot be used to estimate fuel for electricity.

EIA's preferred means of resolving any questionable response is via direct communication with the respondent, usually via phone or e-mail. In cases where the reported data appeared to be incorrect or was missing, and EIA was unable to resolve the matter with the respondent, the following estimation approaches were used for the 2001 data:

- In cases where electric generation appeared reasonable, but fuel consumption was inconsistent with generation, fuel consumption by prime mover was estimated using 2000 heat rates and the assumption that the fuel shares for that prime mover in 2001 were the same as in 2000.
- If the reported electric generation data appeared to be in error, or if the facility was a non-respondent, a regression methodology was used to estimate generation and fuel consumption for the facility. The regression methodology relied on 2001 data for other facilities to make estimates for erroneous or missing responses. The basic technique employed is described in the paper Model-Based Sampling and Inference, found on the EIA web site at http://www.eia.doe.gov/cneaf/electricity/page/forms.html.

- UTO was estimated by applying the power to steam ratio calculated for the facility in 2001.

Overall, of the approximately 2,600 facilities in the Form EIA-906 frame for 2003, some estimation was performed for 803 facilities. These facilities account for approximately 4 percent of the generation in the frame and about 20 percent of the fuel consumption.

Adjusting Monthly Data to Annual Data. In the case of plants that are not part of the monthly sample, data are collected once a year as annual totals. The annual data are allocated to the months using the pattern established by the plants that are part of the monthly sample.

Confidentiality of the Data. Most of the data collected on the Form EIA-906 are not considered confidential. However, the reported fuel stocks at the end of the reporting period are considered confidential and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45Federal Register 59812 (1980)).

Form EIA-920

The Form EIA-920, "Combined Heat and Power Plant Report" is used to collect monthly plant-level data on generation, fuel consumption, stocks, and fuel heat content of combined heat and power (CHP) plants from a model-based sample of approximately 300 plants. The form is also used to collect these statistics from the rest of the frame on an annual basis.

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

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. Relating to the Form EIA-759, 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 define 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 further modified to include useful thermal output data. In January 2004, collection of useful thermal output data and data from combined heat and power plants was discontinued on Form EIA-906.

Data Processing and Data System Editing. Approximately one half of the responses to the Form EIA-920 in 2004 were received as electronic submissions. These submissions were directly entered into a computerized database. Anomalous data were identified via range checks, comparisons with historical data, and consistency checks (for example, whether the fuel consumption and generation numbers for a given facility and month are consistent). These edit checks were performed as the data were provided, and most problems that were encountered were resolved during the reporting process. Those plants that were unable to use the electronic reporting medium provided the data in hard copy, typically via fax. These data were manually entered into the computerized database. The data were subjected to the same edits as those that were electronically submitted. Resolution of questionable responses was done via telephone or email contact with the respondent.

Useful thermal output (UTO) is the thermal energy, usually in 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 consumption for generation by prime mover type. Fuel consumption to produce UTO can then be estimated by subtraction (i.e., consumption for UTO = total consumption – consumption for generation). UTO is then estimated by multiplying consumption for UTO by an assumed thermal conversion factor of 80 percent.

Fuel consumption data is imputed for non-respondents, including out-of-sample annual respondents until their data is 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. UTO is estimated by multiplying the heat equivalent of generation by the historical ratio of UTO to the heat equivalent of generation. (The heat equivalent of generation is the product of generation in kilowatt-hours multiplied by 3412 Btus per kilowatt-hour.) Fuel for UTO is then computed by dividing UTO by the assumed estimated thermal conversion factor of 80 percent.

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 2003 power to steam ratio[1] or with the 2003 industry average power to steam ratio if the plant's 2003 value also seemed questionable.

- 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. The 2004 data affected by these adjustments is marked preliminary in this and other EIA publications.

Finalization of the Monthly Data and Annual Totals. The EIA-920 data is 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 fails edit checks and have data problems that cannot be resolved, generation and consumption is imputed monthly. The sum of the revised monthly data are the final annual totals for each state, fuel and sector combination.

[1] The power to steam ratio is computed as (Generation in kilowatt-hours x 3412 Btus per kilowatt-hour / 1 million)/(UTO in millions of Btus).

Confidentiality of the Data. Most of the data collected on the Form EIA-920 are not considered confidential. However, the reported fuel stocks at the end of the reporting period are considered confidential and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45Federal Register 59812 (1980)).

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) from electric generating plants for 2003 and 2004. 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 NOx emissions for all plants are made by applying an emissions factor to fuel consumption data collected by EIA. An emission factor is the average quantity of a pollutant released from a power plant, assuming no use of pollution control equipment, when a unit of fuel is burned. 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 NOx 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 adding to 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 A.1, which lists the 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 firing configuration of a boiler and whether or not the boiler is a wet-bottom or dry-bottom design.[2] These distinctions are shown in Table A.1.

[2] 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

In the case of SO_2 and NOx, the initial estimate of uncontrolled emissions is reduced to account for the plant's operational pollution control equipment, when data on control equipment is available from the EIA-767 survey. A special case for removal of SO_2 is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO_2 emission factors shown in Table A.1 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 NOx 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 is incomplete and is not used in this report.). The CEMS data account for the bulk of SO_2 and NOx emissions from the electric power industry. For those plants for which CEMS data is available, the EIA estimates of SO_2 and NOx emissions are employed for the limited purpose of allocating emissions by fuel, since the CEMS data itself does not provide a detailed breakdown of plant emissions by fuel. For plants for which CEMS data is 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 CO2 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. The fuel-specific emission factor from Table A.1 is then multiplied by the fuel consumption in MMBtu and a combustion factor of 99 percent (to account for incomplete combustion) to estimate CO2 emissions.

In the case of coal, the emission factors are specific to coal rank. In a 1994 study, EIA determined emission factors by rank and state. These state-level factors are weighted by production in tons to calculate national average CO2 factors for each rank of coal.[3] The national average factors are then used to calculate emissions for the coal-burning plants.

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, NOx control regulations require many plants to install low-NOx 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 NOx emissions estimation approach accounts for the combined effect of the equipment (Table A.1). However, control equipment information is available only for plants that report on the Form EIA-767. If a plant does not report on this form, which is limited to power plants with combustion-fired boilers[4] with a minimum generating capacity of 10 megawatts (nameplate), pollution control equipment data is unavailable from EIA sources.

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

- For steam electric plants that report on the Form EIA-767, uncontrolled emissions are estimated using the emission factors shown in Table A.1 and 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 NOx, the reduction percentages shown in Table A.3. are applied to the uncontrolled estimates.

- For plants and prime movers not reported on the Form EIA-767 survey, uncontrolled emissions are estimated using the Table A.1 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 is 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.

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*, 40th Edition, 1992.

[3] For a description of the methodology and data used to develop the EIA CO2 emission factors, see B. D. Hong and E. R. Slatick, "Carbon Dioxide Emission Factors for Coal," Quarterly Coal Report, January-March 1994, DOE/EIA-0121(94/1Q) (Washington, DC, August 1994), Energy Information Administration.

[4] Boilers that rely entirely on waste heat to boil water, including the heat recovery portion of most combined cycle plants, do not report on the Form EIA-767.

- As noted earlier, the applicable emission factor for plants using boilers depends in part of the type of boiler (wet-bottom or dry-bottom) and the boiler firing configuration. However, this information is unavailable for steam electric plants that do not report on the Form EIA-767. For these cases, the plant is assumed to have a dry bottom, non-cyclone boiler using a firing method that falls into the "All Other" category shown on Table A.1.[5]
- For the plants that do not report on the Form EIA-767, pollution control equipment data is unavailable and the uncontrolled estimates are not reduced.

- If actual emissions of SO_2 or NOx 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 is 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's 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.

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

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
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, Carbon Dioxide and Nitrogen Oxide Emission Factors

SO2 UNCONTROLLED EMISSION FACTORS

FUEL AND EIA FUEL CODE	SOURCE NOTES	EMISSIONS UNITS (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	BOILER TYPE/FIRING CONFIGURATION					
			CYCLONE	FLUIDIZED BED	OPPOSED FIRING	SPREADER STOKER	TANGENTIAL	ALL OTHER
AGRICULTURAL BYPRODUCTS (AB)	**	Lbs per ton	0.08	0.01	0.08	0.08	0.08	0.08
BLAST FURNACE GAS (BFG)	Data source is: ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10100704, including footnotes 1 and 7).	Lbs per MMCF	3.50	0.35	3.50	3.50	3.50	3.50
BITUMINOUS COAL (BIT)*	**	Lbs per ton	38.00	3.10	38.00	38.00	38.00	38.00
BLACK LIQUOR (BLQ)	**	Lbs per ton ***	7.00	0.70	7.00	7.00	7.00	7.00
DISTILLATE FUEL OIL (DFO)*	**	Lbs per MG	142.00	14.20	142.00	142.00	142.00	142.00
JET FUEL (JF)*	**	Lbs per MG	142.00	14.20	142.00	142.00	142.00	142.00
KEROSENE (KER)*	**	Lbs per MG	142.00	14.20	142.00	142.00	142.00	142.00
LANDFILL GAS (LFG)	Data source is: ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10100711, including footnotes 1 and 7).	Lbs per MMCF	3.50	0.35	3.50	3.50	3.50	3.50
LIGNITE COAL (LIG)*	**	Lbs per ton	30.00	1.00	30.00	30.00	30.00	30.00
MUNICIPAL SOLID WASTE (MSW)	**	Lbs per ton	1.70	0.17	1.70	1.70	1.70	1.70
NATURAL GAS (NG)	**	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60
OTHER BIOMASS GAS (OBG)	See LFG	Lbs per MMCF	3.50	0.35	3.50	3.50	3.50	3.50
OTHER BIOMASS LIQUIDS (OBL)	Factor is for methanol; see ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10101601, including footnotes 1 and 3). Per footnote 3, the assumed sulfur content is 1 percent.	Lbs per MG	1.42	1.42	1.42	1.42	1.42	1.42
OTHER BIOMASS SOLIDS (OBS)	Same as AB	Lbs per ton	0.08	0.01	0.08	0.08	0.08	0.08
OTHER GASES (OG)	Data source is: ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10100701, process gas for large boilers, including footnotes 1 and 7).	Lbs per MMCF	3.50	0.35	3.50	3.50	3.50	3.50
OTHER (OTH)	Same as NG.	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60
PETROLEUM COKE (PC)*	**	Lbs per ton	39.00	3.90	39.00	39.00	39.00	39.00
PROPANE GAS (PG)	Same as NG	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60
RESIDUAL FUEL OIL (RFO)*	**	Lbs per MG	157.00	15.70	157.00	157.00	157.00	157.00
SYNTHETIC COAL (SC)*	Same as BIT.	Lbs per ton	38.00	3.10	38.00	38.00	38.00	38.00
SLUDGE WASTE (SLW)	**	Lbs per ton	2.80	0.28	2.80	2.80	2.80	2.80
SUBBITUMINOUS COAL (SUB)*	**	Lbs per ton ***	35.00	3.10	35.00	38.00	35.00	35.00
TIRE DERIVED FUEL (TDF)*	**	Lbs per ton	38.00	3.80	38.00	38.00	38.00	38.00
WASTE COAL (WC)*	Same as BIT.	Lbs per ton	38.00	3.10	38.00	38.00	38.00	38.00
WOOD WASTE LIQUIDS (WDL)	Same as OBL.	Lbs per MG	1.42	1.42	1.42	1.42	1.42	1.42
WOOD WASTE SOLIDS (WDS)	**	Lbs per ton	0.08	0.01	0.08	0.08	0.08	0.08
WASTE OIL (WO)*	**	Lbs per MG	147.00	14.70	147.00	147.00	147.00	147.00

* 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 a sulfur content for TDF. The value used (1.56 percent) is from:http://www.epa.gov/appcdwww/aptb/EPA-600-R-01-109A.pdf, Table A-11.
** Source is EPA emission factors reported in http://www.epa.gov/ttn/chief/ap42/ and http://www.epa.gov/ttn/chief/software/fire/index.html.
*** Although SLW and BLQ consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Table A1. Sulfur Dioxide, Carbon Dioxide and Nitrogen Oxide Emission Factors (Continued)

NOX UNCONTROLLED EMISSION FACTORS

			BOILER TYPE/FIRING CONFIGURATION All Dry-Bottom Boilers, Except Wet-Bottom as Indicated by Values in Brackets					
FUEL AND EIA FUEL CODE	**SOURCE NOTES**	**EMISSIONS UNITS** (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	CYCLONE	FLUIDIZED BED	OPPOSED FIRING	SPREADER STOKER	TANGENTIAL	ALL OTHER
AGRICULTURAL BYPRODUCTS (AB)	**	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20
BLAST FURNACE GAS (BFG)	Data source is: ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10100704, including footnotes 1 and 7).	Lbs per MMCF	15.40	15.40	15.40	15.40	15.40	15.40
BITUMINOUS COAL (BIT)	**	Lbs per ton	33.00	5.00	22.00	11.00	15.0 [14.0]	22.0 [31.0]
BLACK LIQUOR (BLQ)	**	Lbs per ton ***	1.50	1.50	1.50	1.50	1.50	1.50
DISTILLATE FUEL OIL (DFO)	**	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00
JET FUEL (JF)	**	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00
KEROSENE (KER)	**	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00
LANDFILL GAS (LFG)	Data source is: ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10100711, including footnotes 1 and 7).	Lbs per MMCF	72.40	72.40	72.40	72.40	72.40	72.40
LIGNITE COAL (LIG)	**	Lbs per ton	15.00	3.60	13.00	5.80	7.10	7.1 [13.0]
MUNICIPAL SOLID WASTE (MSW)	**	Lbs per ton	5.90	5.90	5.90	5.90	5.90	5.90
NATURAL GAS (NG)	**	Lbs per MMCF	280.00	280.00	280.00	280.00	170.00	280.00
OTHER BIOMASS GAS (OBG)	See LFG	Lbs per MMCF	72.40	72.40	72.40	72.40	72.40	72.40
OTHER BIOMASS LIQUIDS (OBL)	Factor is for methanol; see ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10101601, including footnotes 1 and 3). Per footnote 3, the assumed sulfur content is 1 percent.	Lbs per MG	1.66	1.66	1.66	1.66	1.66	1.66
OTHER BIOMASS SOLIDS (OBS)	Same as AB	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20
OTHER GASES (OG)	Data source is: ftp://ftp.epa.gov/EmisInventory/draftnei2002/point/documentation/egu2002doc.pdf (see Table 6, SCC code 10100701, process gas for large boilers, including footnotes 1 and 7).	Lbs per MMCF	14.90	14.90	14.90	14.90	14.90	14.90
OTHER (OTH)	Same as NG.	Lbs per MMCF	1.50	1.50	1.50	1.50	1.50	1.50
PETROLEUM COKE (PC)	**	Lbs per ton	21.00	21.00	21.00	21.00	21.00	21.00
PROPANE GAS (PG)	Same as NG	Lbs per MMCF	19.00	19.00	19.00	19.00	19.00	19.00
RESIDUAL FUEL OIL (RFO)	**	Lbs per MG	47.00	47.00	47.00	47.00	32.00	47.00
SYNTHETIC COAL (SC)	Same as BIT.	Lbs per ton	33.00	5.00	22.00	11.00	15.00	22.00
SLUDGE WASTE (SLW)	**	Lbs per ton	5.00	5.00	5.00	5.00	5.00	5.00
SUBBITUMINOUS COAL (SUB)	**	Lbs per ton ***	17.00	5.00	12.00	8.80	8.40	12.0 [24.0]
TIRE DERIVED FUEL (TDF)	**	Lbs per ton	33.00	5.00	22.00	11.00	15.00	22.00
WASTE COAL (WC)	Same as BIT.	Lbs per ton	21.70	21.70	21.70	21.70	21.70	21.70
WOOD WASTE LIQUIDS (WDL)	Same as OBL.	Lbs per MG	1.66	1.66	1.66	1.66	1.66	1.66
WOOD WASTE SOLIDS (WDS)	**	Lbs per ton	1.50	1.50	1.50	1.50	1.50	1.50
WASTE OIL (WO)	**	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00

** Source is EPA emission factors reported in http://www.epa.gov/ttn/chief/ap42/ and http://www.epa.gov/ttn/chief/software/fire/index.html.
*** Although SLW and BLQ consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Table A1. Sulfur Dioxide, Carbon Dioxide and Nitrogen Oxide Emission Factors (Continued)

CO2 UNCONTROLLED EMISSION FACTORS

FUEL AND EIA FUEL CODE	SOURCE NOTES	FACTOR (POUNDS OF CO2 PER MILLION BTUS)*
BLAST FURNACE GAS (BFG)	**	116.97
BITUMINOUS COAL (BIT)	**	205.45
DISTILLATE FUEL OIL (DFO)	**	161.27
GEOTHERMAL (GEO)	Estimate from EIA, Office of Integrated Analysis and Forecasting	0.34
JET FUEL (JF)	**	159.41
KEROSENE (KER)	**	159.41
LANDFILL GAS (LFG)	**	115.12
LIGNITE COAL (LIG)	**	215.53
MUNICIPAL SOLID WASTE (MSW)	Estimate from EIA, Office of Integrated Analysis and Forecasting	14.63
NATURAL GAS (NG)	**	116.97
OTHER BIOMASS GAS (OBG)	**	115.11
OTHER GASES (OG)	**	141.54
PETROLEUM COKE (PC)	**	225.13
PROPANE GAS (PG)	**	139.04
RESIDUAL FUEL OIL (RFO)	**	173.72
SYNTHETIC COAL (SC)	Bitimuinous coal factor is used.	205.45
SUBBITUMINOUS COAL (SUB)	**	212.58
WASTE COAL (WC)	**	205.16
WASTE OIL (WO)	**	163.61

* CO2 factors do not vary by boiler type or firing configuration.
** Source is EPA emission factors reported in http://www.epa.gov/ttn/chief/ap42/ and http://www.epa.gov/ttn/chief/software/fire/index.html.

Table A2. Carbon Dioxide Emission Factors for Coal by Rank and State of Origin

Rank	State of Origin	Factors (Pounds per Million Btu)
Anthracite	Pennsylvania	227.38
Bituminous	Alabama	205.46
Bituminous	Arizona	209.68
Bituminous	Arkansas	211.60
Bituminous	Colorado	206.21
Bituminous	Illinois	203.51
Bituminous	Indiana	203.64
Bituminous	Iowa	201.57
Bituminous	Kansas	202.79
Bituminous	Kentucky: East	204.80
Bituminous	Kentucky: West	203.23
Bituminous	Maryland	210.16
Bituminous	Missouri	201.31
Bituminous	Montana	209.62
Bituminous	New Mexico	205.71
Bituminous	Ohio	202.84
Bituminous	Oklahoma	205.93
Bituminous	Pennsylvania	205.72
Bituminous	Tennessee	204.79
Bituminous	Texas	204.39
Bituminous	Utah	204.08
Bituminous	Virginia	206.23
Bituminous	Washington	203.62
Bituminous	West Virginia	207.10
Bituminous	Wyoming	206.48
Subbituminous	Alaska	214.00
Subbituminous	Colorado	212.72
Subbituminous	Iowa	200.79
Subbituminous	Missouri	201.31
Subbituminous	Montana	213.42
Subbituminous	New Mexico	208.84
Subbituminous	Utah	207.09
Subbituminous	Washington	208.69
Subbituminous	Wyoming	212.71
Lignite	Arkansas	213.54
Lignite	California	216.31
Lignite	Louisiana	213.54
Lignite	Montana	220.59
Lignite	North Dakota	218.76
Lignite	South Dakota	216.97
Lignite	Texas	213.54
Lignite	Washington	211.68
Lignite	Wyoming	215.59

Source: Energy Information Administration, Quarterly Coal Report, Jan.-Mar. 1994, DOE-EIA-0121(94/Q1) (Washington, D.C, August 1994), pp. 1-8.)

Table A3. Nitrogen Oxide Control Technology Emissions Reduction Factors

Nitrogen Oxide Control Technology	EIA-767 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 Nitrogen Oxide 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 Nitrogen Oxide Burners	SN and LN	50
Slagging	SC	20

1. Starting with 1995 data, reduction factors for advanced overfire air, low nitrogen oxide burners and overfire air were reduced by 10 percent.
Source: Babcox and Wilcox, *Steam: Its Generation and Use*, 40th Edition, 1992.

Table A4. 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.

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