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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;
Internet e-mail: robert.schnapp@eia.doe.gov

Dr. Suraj P. Kanhouwa (202/287-1919)
Chief, Electric Market Assessment
Internet e-mail: suraj.kanhouwa@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:

Roger L. Sacquety (202/287-1745),
Internet e-mail: roger.sacquety@eia.doe.gov;

Lead Coordinators:
Elsie Bess (202/287-1730)
Internet e-mail: elsie.bess@eia.doe.gov;

Linda Bromley (202/287-1748)
Internet e-mail: linda.bromley@eia.doe.gov;

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

Generation
Melvin E. Johnson (202/287-1754)
Internet e-mail: melvin e.johnson@eia.doe.gov;
Channele Carner (202/287-1928)
Internet e-mail: channele.carner@eia.doe.gov;

Capacity
Kenneth McClevey (202/287-1732)
Internet e-mail: kenneth.mcclevey@eia.doe.gov;
Betty Williams (202/287-1927)
Internet e-mail: betty.williams@eia.doe.gov;

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

Fuel
Melvin E. Johnson (202/287-1754)
Internet e-mail: melvin e.johnson@eia.doe.gov;
Channele Carner (202/287-1928)
Internet e-mail: channele.carner@eia.doe.gov;

Emissions
Natalie Ko (202/287-1957)
Internet e-mail: natalie.ko@eia.doe.gov;

Trade
Rodney Dunn (202/287-1676)
Internet e-mail: rodney.dunn@eia.doe.gov;

Retail Customers, Sales, and Revenue
Rodney Dunn (202/287-1676)
Internet e-mail: rodney.dunn@eia.doe.gov;

Revenue and Expense Statistics
Karen McDaniel (202/287-1754)
Internet e-mail: karen.mcdaniel@eia.doe.gov;

Demand-Side Management
Rodney Dunn (202/287-1676)
Internet e-mail: rodney.dunn@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 Roger L. Sacquety at (202/287-1745), or Internet e-mail: roger.sacquety@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 2001 presents a summary of electric power industry statistics at the national level. The objective of the publication is to provide industry decisionmakers, 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 electric utility 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: generation; capacity; demand, capacity resources, and capacity margins; emissions; trade; retail customers, sales, and revenues; 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 six forms filed annually by electric utilities and deregulated electric power producers with the EIA and five forms filed with other government organizations. The EIA forms are described in detail in the "Technical Notes."

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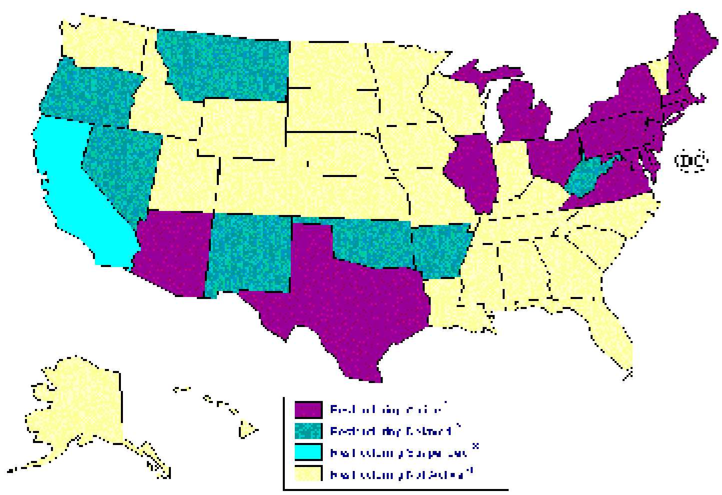
Introduction

The pace of restructuring the electric power industry slowed significantly in 2001. Market volatility and associated price increases in California during the 2000-2001 period caused serious financial problems for the investor-owned electric utilities in the State. The financial turmoil was capped by the bankruptcy filing of Pacific Gas and Electric Company and the near bankruptcy of Southern California Edison Company.

As the creditworthiness of the investor owned electric utilities deteriorated, the State of California stepped in to buy power at high prices. This intervention created financial problems for the State and imposed burdens that are likely to last for a number of years in the future. In addition, electricity customers in the State will be required to pay rates that are significantly higher than those prevailing in the prior periods. As a result of the California situation, other States in the Northwest also experienced varying degrees of economic impacts as power prices increased regionally.

The bankruptcy of Enron Corporation in the midst of allegations of financial improprieties contributed to charges that the power markets could be manipulated and that the regulatory authorities lacked the tools to monitor such abuses in a timely fashion. Overall, the above events have, at least temporarily, led to an erosion of confidence in the efficacy of competitive power markets. As a result, nearly half the States have adopted a go-slow approach. Others like New Mexico and Oklahoma have delayed implementation. California, which spearheaded the movement toward deregulation, has stepped back. By the end of 2001, restructuring had either been delayed or suspended in 8 States that previously enacted legislation or issued regulatory orders for its implementation (Figure 1). Eighteen other States that had ongoing investigations either at the legislative or regulatory levels in the year 2000 reported no such activity in 2001.

Figure 1: Status of State Electric Utility Deregulation Activity, as of January 2002



[1]These States have either enacted enabling legislation or issued a regulatory order to implement retail access. Retail access is either currently available to all or some customers or will soon be available. Some States are currently running pilot programs, and they will begin to implement retail access in the near future: Arizona, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia.

[2]These States have either passed legislation or issued regulatory orders to delay implementing retail access: Arkansas, Montana, Nevada, New Mexico, Oklahoma, and Oregon. Although West Virginia passed legislation that approved the PSC's plan to restructure and implement retail access, the process is delayed until a bill for tax reform is enacted.

[3]The CPUC ordered suspension of direct retail access.

[4]These States have not enacted enabling legislation to restructure the electric power industry or implement retail access: Alabama, Alaska, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, Wisconsin, and Wyoming.

Source: Energy Information Administration.

As a result of the financial turmoil in the power sector, commitments and planning for new plants began to slow in 2001. Infrastructure investments including additions to transmission capability have not kept pace with increases in demand for power and trading requirements. These developments retard the growth of a fully competitive market for power.

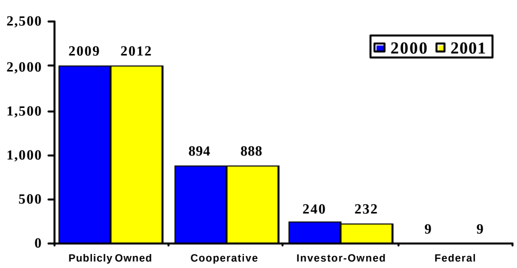
The electric power industry is and will continue to be in a state of flux in the foreseeable future. FERC's efforts to create a competitive market for power nationally will hinge on the critical support it receives from the States. Changes will continue to emerge albeit at a slower pace.

The following is a summary of statistics gathered on the U.S. electric power industry for 2001.

Industry Profile

The electric power industry in the United States is composed of traditional electric utilities, and nontraditional participants, including energy service providers, power marketers, and independent power producers (IPP). Electric utilities include investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A utility is defined as a corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. In total, there are more than 3,100 electric utilities in the United States (Figure 2).

Figure 2: Composition of the Electric Utility Industry in the United States, 2001



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

Historically, the most influential of these entities have been the vertically integrated investor-owned utility companies that provided generation, transmission, distribution, and retail energy services for all customers in a designated service territory. However, the industry has continued to change from this vertically integrated structure to a functionally unbundled industry with a competitive market for power generation. As a result, there were 128 active power marketers operating by the end of 2001.

Electric power that is sold to end users may be generated by electricity generators that are traditional electric utilities, by independent power producers, or by combined heat and power producers. An independent power producer is an entity defined as a corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and is not an electric utility. Combined heat and power producers (typically industrial cogenerators) are plants designed to produce both heat and electricity from a single heat source. There are approximately 2,800 unregulated independent power producers or combined heat and power plants in the United States.

Generation

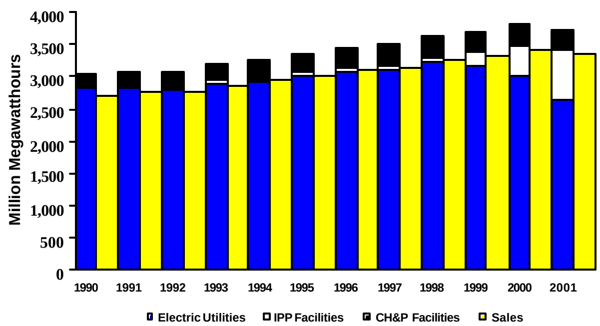
In 2001, the total U.S. net generation of electricity was 3,734 billion kilowatthours, 2-percent lower than 2000. This decrease is unusual in that net U.S. generation has historically increased from year to year. This is only the second time in over 50 years that there has been a decrease in net generation (Figure 3). Demand reductions caused by an economic slowdown explain somewhat corresponding declines in generation.

Because nuclear and coal units are typically operated as base load generators (the generating equipment normally operated to serve loads on an around-the-clock basis), they contribute a major share of electric generation. In 2001, coal plants accounted for 51 percent of generation and nuclear plants for 21 percent of generation for a total of 72 percent of power supply, although coal and nuclear plants provide just under 50 percent of total capacity.

In contrast, natural gas and petroleum units typically run in cycling (load-following) service or as peaking capacity for short periods of time to meet the highest daily loads. Consequently, natural gas and petroleum plants account for only 20 percent of generation, although they make up 38 percent of total capacity.

While net generation dropped for the industry overall, the independent power producers' share of net generation was up sharply in 2001. This is a result of both new plant construction by independent producers and plant divestitures by investor owned utilities. In contrast to IPP electric–only production, net generation by combined heat and power producers has remained fairly constant from 1996 through 2001 at 8 to 9 percent of the total net generation.

Figure 3: Total Net Generation Compared to Total Retail Sales, 1990 through 2001



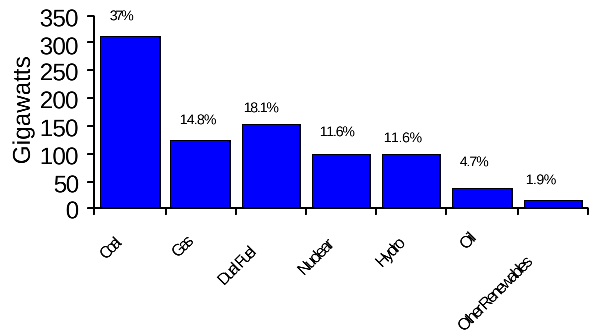
Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report," and Form EIA-906, "Power Plant Report."

Capacity

In 2001, total net summer generating capacity was 848 gigawatts, up 4.5 percent from the year 2000. Large increases in natural gas capacity, which increased by 31 percent to 126 gigawatts, drove most of this increase in capacity.

The total amount of U.S. net summer capacity for 2001 of coal-fired capacity is more than two times higher than the capacity for any other single energy source (Figure 4). However, most "dual fuel" generating plants consume natural gas most of the time and use oil as a back-up source. When the aggregate capacity of these dual fuel plants is added to the natural gas-only capacity, the total for natural gas has a 33-percent share of the total U.S. net summer capacity for 2001. The 2001 net summer capacity for "other renewables" fuel sources is dominated by biomass and municipal solid waste generating plants. Contributions by these sources increased 4 percent over the year 2000, resulting in an additional 608 MW of net summer capacity from this fuel source.

Figure 4: Share of U.S. Net Summer Capacity by Energy Source, Year-End 2001

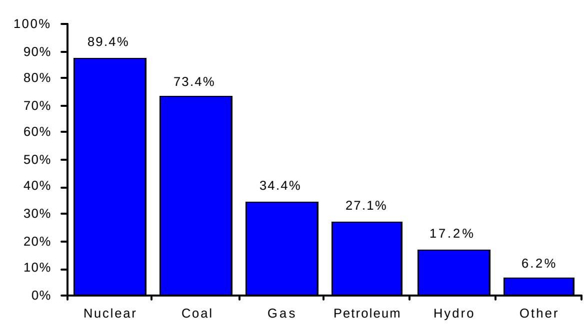


Note: Net Summer capacity of 0.2 percent from blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels is not included.

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

The aggregate annual capacity factor is an index that shows the average production by a group of generating facilities as a percent of the maximum possible production over the year 2001. At year-end 2001, nuclear plant capacity factors were at 89.4 percent (Figure 5) and coal plant capacity factors were at 73.4 percent, consistent with base load operation. In contrast, gas and oil units had, respectively, capacity factors of only 34.4 percent and 27.1 percent, reflecting load-following and peaking operations. Hydroelectric generators had an average capacity factor of only 17.2 percent.

Figure 5: Average Capacity Factor by Energy Source, 2001



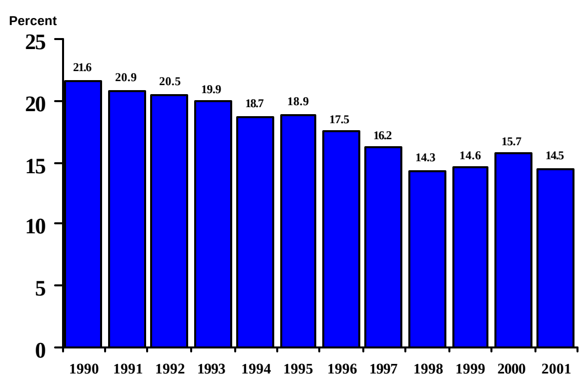
Source: Energy Information Administration, Form EIA-906, "Power Plant Report."

Demand, Capacity Resources, and Capacity Margins

Available Capacity Margin is defined as the difference between Available Resources and Net Internal Demand, expressed as a percent of Available

Resources. This is the capacity available to cover random factors such as forecast outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage. Variations from capacity margins in regional tables may exist due to differences in reporting methods for purchases and sales. Summer capacity margins in the contiguous United States declined over the past 12 years by over 7 percent. Despite a brief increase in 1999 and 2000, the downward trend has reemerged with nationwide capacity margins at 14.5 percent in 2001 (Figure 6). Although net internal demand has increased an average of 2 percent per year over the period from 1999 to 2001, capacity resources have only increased approximately 1 percent a year in the corresponding time period.

Figure 6: Summer Capacity Margins, Contiguous U.S., 1990-2001



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

According to the North American Reliability Council (NERC), a reduction in capacity margins in 2001 is primarily due to variances in qualitative assumptions incorporated in the estimation process for that year. As an example, drought-induced restrictions on hydroelectric generating capacity in the Northwest and South played a critical role. Other influencing factors for the 2001 estimates include the then prevailing concerns with respect to the availability and adequacy of natural gas supplies and the higher-than-usual outages in the West and South. Attempts to secure suitable interconnection and transmission access agreements were frustrated in varying degrees by siting and permitting hurdles, difficulties in financing due to market uncertainties, and fuel supply adequacy issues.

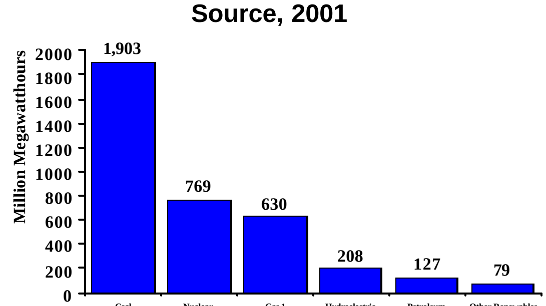
Fuel

Consumption of coal for electricity generation was down 2.2 percent from 2000, going from 995 to 973 million short tons in 2001. Use of petroleum for electricity generation increased 13.9 percent, going from 195 million barrels in 2000 to 222 million barrels in 2001. Consumption of natural and other gases used for electricity generation increased only 0.7 percent to 6 trillion cubic feet in 2001.

In 2001, the average cost of natural gas to electric utilities increased 4.3 percent and the average cost of coal increased 2.6 percent. However, these average prices do not reflect the extraordinary volatility in the spot markets for natural gas and coal in 2001. For example, the spot price for natural gas at the Henry Hub trading point exceeded 9.00 per million Btu in January 2001, but was under 3.00 per million Btu by Fall. Coal spot prices were also very high at the beginning of 2001 and moderated as the year progressed. The high price of spot market natural gas for much of the year may be one factor explaining why natural gas generation increased only slightly even as many new natural gas-fired plants entered commercial operation.

The total consumption of these fuels and others resulted in the production of 3,734 billion kilowatthours (Figure 7). Approximately 1,900 billion kilowatthours, over half of the total net generation, was produced by coal-fired generators. Nuclear and gas-fired generation accounted for most of the balance with 21 and 17 percent, respectively, of the total net generation.

Figure 7: U.S. Net Generation by Energy Source, 2001



1 Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels resulting in net generation of 13,767 thousand megawatthours are not included.
An additional 4,254 thousand megawatthours, not shown here, were generated from "Other" energy sources.

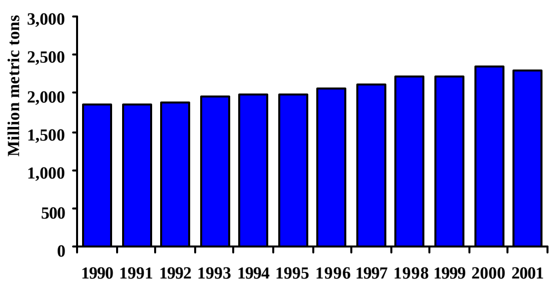
Source: Energy Information Administration, Form EIA-906, "Power Plant Report."

Emissions

Electricity generators must adhere to rigorous environmental regulations in the United States. Many have invested billions of dollars in emissions reduction technologies to meet these requirements. Nonetheless, fossil fuel combustion continues to be the largest single source of industrial air emissions according to the United States Environmental Protection Agency[1].

Carbon dioxide emissions have continued to rise steadily since 1990 resulting in a 23-percent increase in 2001 over 1990 levels (Figure 8). On the other hand, nitrogen oxides have steadily decreased in the 1990-2000-time period, with 2001 levels 11-percent less than they were in 1990. Despite rising during 1996-1998 and 2001, sulfur dioxide emissions are 12-percent lower than they were in 1990.

Figure 8: Carbon Dioxide Emissions, 1990 – 2001



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

Trade

Restructuring of the industry has dramatically increased trade in some parts of the country. In 2001, purchases by electric utilities increased to 2,976 billion kilowatthours, a 32-percent increase over 2000 purchases of 2,250 billion kilowatthours.

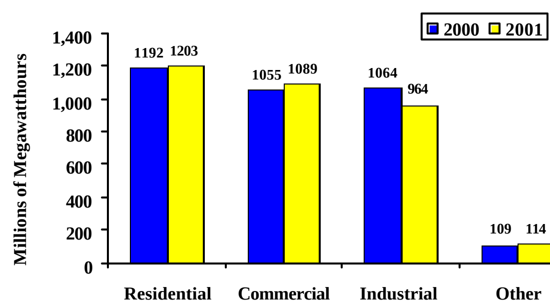
Retail Customers, Sales, and Revenues

[1] See the EPA website at http://www.epa.gov/ cleanenergy/impacts/ impacts.htm#chart.

Total retail sales in 2001 were 3,370 million megawatthours, down slightly from the 2000 level of 3,421 million megawatthours. This represents an approximate decrease of 0.6 percent. Further examination shows the biggest decreases in retail sales occurred on the West Coast, as a result of California's electricity crisis.

Sales between the three major sectors are relatively well balanced in the United States. The residential sector, at 1,203 million megawatthours, is larger than the commercial sector or industrial sector by approximately 10 percent and 25 percent, respectively (Figure 9).

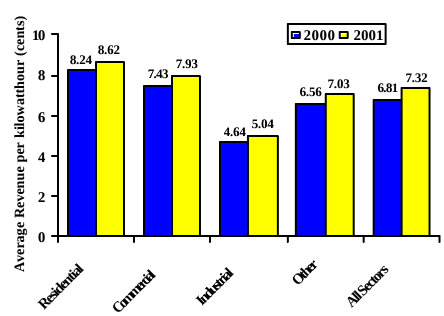
Figure 9: U.S. Total Electric Industry, Retail Sales to Ultimate Consumers by Sector, 2000 and 2001



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

In 2001, annual revenues increased by 6 percent to 247 billion. As a consequence, average revenues, which reflect the average cost to consumers, were up by 7.5 percent to 7.32 cents per kWh (Figure 10).

Figure 10: U.S. Average Revenue, by Sector, 2000 and 2001

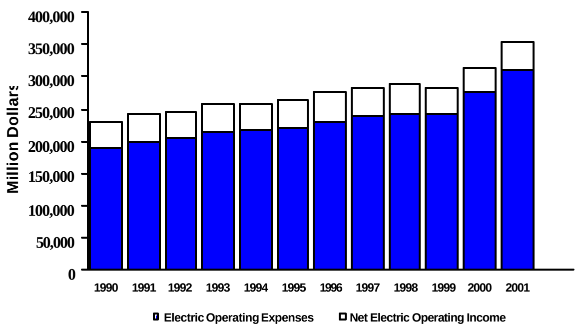


Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Revenue and Expense Statistics

In 2001, electric utility revenues once again surpassed 300 billion (Figure 11). Electric utility revenues and expenses for 2001 differed among the various utility ownership classes. Investor-owned utilities (IOUs), by far the largest ownership category, had increases in both total revenues and total operating expenses. IOU operating revenues were up by 14 percent to 268 billion, while operating expenses increased by 12 percent to 235 billion. Most of the increase in expenses could be attributed to increases in production costs and purchased power costs. Increased natural gas costs were a major cause of these increases.

Figure 11: Revenue and Expense Statistics for Major Electric Utilities, 1990 through 2001



Sources: Energy Information Administration, Form EIA-412, "Annual Electric Industry Financial Report;" Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees and Others;" Rural Utilities Services (RUS) Form 7, "Financial and Statistical Report;" and RUS Form 12, "Operating Report-Financial."

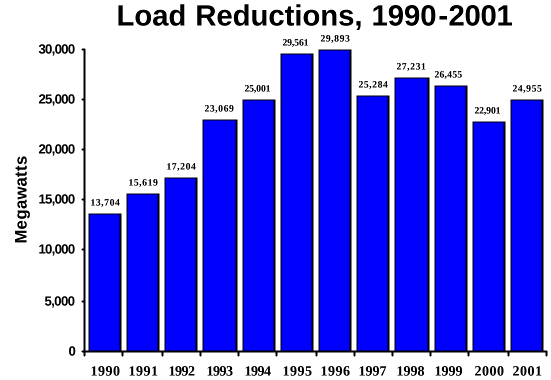
Financial results for the other utility ownership types differed sharply from those for IOUs. Revenues for publicly owned utilities were up by 16 percent to 48 billion, but expenses increased by approximately 20 percent to 43 billion. Most of this could be accounted for by the increased purchase power costs from 2000 to 2001.

Federal utility revenues increased by 14 percent to 12 billion, while operating expenses increased by 20 percent to 10 billion. Most stable were the financial results for cooperatively owned electric utilities (cooperatives). Cooperatives reported annual revenue increases of 3 percent to 26 billion, with expenses increasing by only 3 percent to 24 billion. The cooperatives' costs and revenues were largely insulated from market changes as a result of long-term contracts.

Demand-Side Management

In 2001, the total peak-load reductions from demand-side management (DSM) in 2001 were 24,955 megawatts, up 9 percent from 2000, and down 6 percent from 1999 (Figure 12). There has been a clear and steady decline in peak-load reduction from DSM measures since 1996. This may reflect a reduced emphasis on integrated resource planning at State regulatory commissions as the resource planning process has become fragmented.

Figure 12: Demand-Side Management Peak Load Reductions, 1990-2001



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

EIA Electric Industry Data Collection

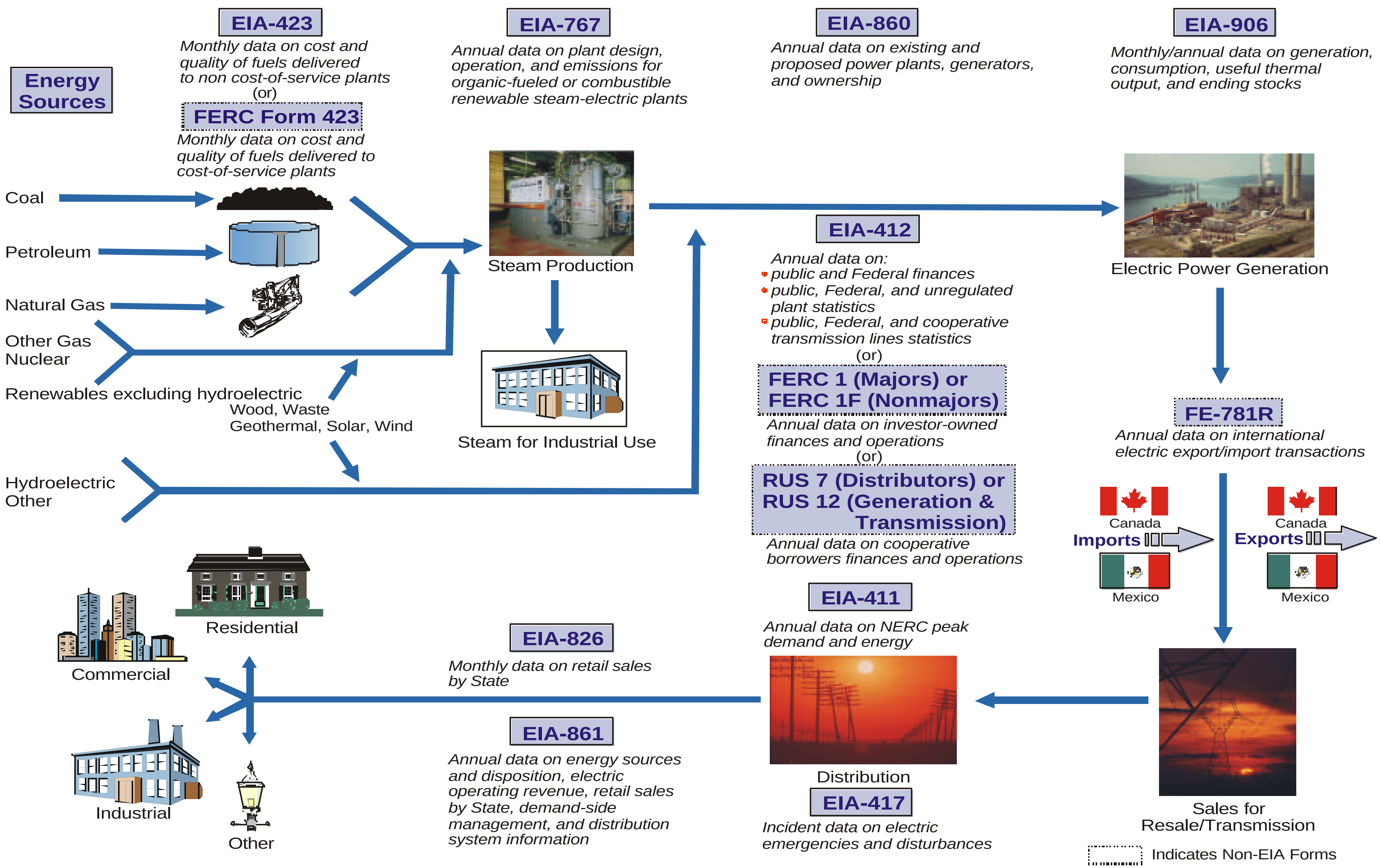


Table ES. Electric Power Industry - Summary Statistics for the United States, 1990 through 2001

Description	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Net Generation (thousand megawatthours)												
Coal[1]	1,903,380	1,966,265	1,881,087	1,873,516	1,845,016	1,795,196	1,709,426	1,690,694	1,690,070	1,621,206	1,590,623	1,594,011
Petroleum[2]	127,629	111,221	118,061	128,800	92,555	81,411	74,554	105,901	112,788	100,154	119,752	126,621
Natural Gas	629,201	601,038	556,396	531,257	479,399	455,056	496,058	460,219	414,927	404,074	381,553	372,765
Other Gases[3]	13,767	13,955	14,126	13,492	13,351	14,356	13,870	13,319	12,956	13,270	11,336	10,383
Nuclear	768,826	753,893	728,254	673,702	628,644	674,729	673,402	640,440	610,291	618,776	612,565	576,862
Hydroelectric[4]	207,548	270,034	313,439	318,868	352,413	344,074	308,108	256,748	276,458	248,911	284,453	289,358
Other Renewables[5]	78,916	80,906	79,423	77,088	77,183	75,796	73,965	76,535	76,213	73,770	68,779	64,372
Other[6]	4,254	4,794	4,024	3,571	3,612	3,571	4,104	3,667	3,487	3,720	4,739	3,616
All Energy Sources	**3,733,521**	**3,802,105**	**3,694,810**	**3,620,295**	**3,492,172**	**3,444,188**	**3,353,487**	**3,247,522**	**3,197,191**	**3,083,882**	**3,073,799**	**3,037,988**
Net Summer Generating Capacity (megawatts)												
Coal[1]	314,230	315,114	315,496	315,786	313,624	313,382	311,386	311,415	310,148	309,372	307,438	307,361
Petroleum[2] Only	39,714	35,890	35,587	40,399	43,202	43,585	43,708	42,695	44,019	45,642	47,296	48,994
Natural Gas Only	125,798	95,705	73,562	75,772	76,348	74,498	75,438	70,685	65,523	60,736	60,836	56,194
Dual Fired	153,482	149,833	146,039	130,399	129,384	128,570	121,958	123,110	120,157	118,913	113,725	113,582
Other Gases[3]	1,670	2,342	1,909	1,520	1,525	1,664	1,661	2,093	1,931	2,069	2,103	1,641
Nuclear	98,159	97,860	97,411	97,070	99,716	100,784	99,515	99,148	99,041	98,985	99,589	99,624
Hydroelectric[4]	98,580	98,881	98,958	98,669	98,725	97,548	99,948	99,249	98,557	95,962	94,450	93,385
Other Renewables[5]	16,180	15,572	15,942	15,444	15,351	15,309	15,300	15,021	14,656	14,281	13,895	12,840
Other[6]	440	523	1,023	810	774	550	550	550	550	545	539	501
All Energy Sources	**848,254**	**811,719**	**785,927**	**775,868**	**778,649**	**775,890**	**769,463**	**763,967**	**754,582**	**746,507**	**739,870**	**734,122**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	674,833	680,941	653,857	638,086	618,389	602,438	589,860	578,640	565,041	554,462	547,946	538,824
Capacity Resources (megawatts)	788,990	808,054	765,744	744,670	737,855	730,376	727,481	711,583	705,360	697,432	692,337	687,341
Capacity Margins (percent)	14.5	15.7	14.6	14.3	16.2	17.5	18.9	18.7	19.9	20.5	20.9	21.6
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	973,076	994,933	949,802	946,295	931,949	907,209	860,594	848,796	842,153	805,140	793,666	792,457
Petroleum (thousand barrels)[2]	222,294	195,228	207,871	222,640	159,715	144,626	132,578	183,618	192,462	172,241	203,669	218,997
Natural Gas (millions of cubic feet)	5,768,117	5,691,481	5,321,984	5,081,384	4,564,770	4,312,458	4,737,871	4,367,148	3,928,653	3,899,718	3,764,778	3,691,563
Other Gases (millions of cubic feet)[3]	515,707	551,355	600,070	503,292	519,581	998,556	844,741	727,389	758,648	716,587	616,179	632,328
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	19,949	20,466	20,373	20,320	21,005	20,806	20,418	20,609	19,750	19,372	18,458	19,081
Petroleum (thousand barrels)[2]	20,379	22,266	26,822	28,845	28,802	27,873	25,562	27,929	26,394	24,077	23,039	26,002
Natural Gas (millions of cubic feet)	977,823	985,263	982,958	949,106	868,569	865,774	834,382	784,015	733,584	717,860	663,963	654,749
Other Gases (millions of cubic feet)[3]	663,977	902,345	873,137	841,769	839,718	809,558	654,799	793,898	831,806	849,446	750,704	809,773
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	993,025	1,015,398	970,175	966,615	952,955	928,015	881,012	869,405	861,904	824,512	812,124	811,538
Petroleum (thousand barrels)[2]	242,673	217,494	234,694	251,486	188,517	172,499	158,140	211,547	218,855	196,318	226,708	244,998
Natural Gas (millions of cubic feet)	6,745,940	6,676,744	6,304,942	6,030,490	5,433,338	5,178,232	5,572,253	5,151,163	4,662,236	4,617,578	4,428,742	4,346,311
Other Gases (millions of cubic feet)[3]	1,179,685	1,453,701	1,473,207	1,345,061	1,359,299	1,808,114	1,499,540	1,521,287	1,590,454	1,566,033	1,366,884	1,442,101
Stocks at Electricity Generators (year end)[7]												
Coal (thousand tons)[1]	140,583	103,440	142,846	120,501	98,826	114,623	126,304	126,897	111,341	154,130	157,876	156,166
Petroleum (millions of cubic feet)[2]	59,214	41,956	55,254	56,591	51,138	48,146	50,821	63,333	62,890	72,183	75,343	83,970
Receipts of Fuel at Electricity Generators												
Coal (thousand tons)[1]	762,815	790,274	908,232	929,448	880,588	862,701	826,860	831,929	769,152	775,963	769,923	786,627
Petroleum (thousand barrels)[2]	124,618	108,272	145,939	181,276	128,749	113,678	89,908	149,258	154,144	147,825	172,051	212,118
Natural Gas (millions of cubic feet)	2,152,366	2,629,986	2,809,455	2,922,957	2,764,734	2,604,663	3,023,327	2,863,904	2,574,523	2,637,678	2,630,818	2,490,979
Cost of Fuel at Electricity Generators (cents per million Btu)												
Coal (thousand tons)[1]	123.1	120.0	121.6	125.2	127.3	128.9	131.8	135.5	138.5	141.2	144.7	145.5
Petroleum (thousand barrels)[2]	389.5	442.0	250.8	212.3	286.3	314.2	266.7	248.1	242.7	254.7	254.6	338.1
Natural Gas (millions of cubic feet)	448.6	430.2	257.4	238.1	276.0	264.1	198.4	223.0	256.0	232.8	215.3	232.1
Emissions (thousand metric tons)												
Carbon Dioxide (CO_2)	2,290,045	2,327,868	2,222,525	2,209,983	2,123,263	2,058,980	1,985,162	1,970,581	1,945,346	1,865,680	1,851,086	1,853,975
Sulfur Dioxide (SO_2)	13,038	10,678	11,791	12,534	12,484	12,125	11,469	13,721	14,246	14,337	14,604	14,779
Nitrogen Oxides (NO_X)	6,118	5,191	5,549	5,999	6,085	6,137	5,908	6,732	6,927	6,717	6,816	6,887
Trade (megawatthours)[8]												
Purchases[9]	2,976,254	2,345,540	2,039,969	2,020,622	1,966,447	1,797,720	1,617,715	1,528,222	1,492,370	1,395,789	1,340,593	1,191,222
Sales for Resale[9]	2,081,384	2,325,652	1,977,753	1,914,916	1,838,539	1,656,090	1,495,015	1,387,966	1,387,137	1,284,273	1,250,314	1,115,946
International Imports and Exports (thousand megawatthours)												
Imports	38,478	48,879	42,923	39,525	43,031	43,497	42,854	46,833	31,358	28,247	21,931	18,445
Exports	18,173	14,829	14,000	13,229	8,974	3,302	3,623	2,010	3,541	2,827	2,305	16,134
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	114,318	111,718	110,383	109,048	107,066	105,343	103,917	102,321	100,860	99,513	98,296	97,095
Commercial	14,940	14,349	14,074	13,887	13,542	13,181	12,949	12,733	12,526	12,367	12,179	12,082
Industrial	574	527	553	540	563	586	581	584	553	548	518	525
Other[10]	1,008	974	935	933	952	894	882	851	795	858	887	859
All Sectors	130,840	127,568	125,945	124,408	122,123	120,004	118,330	116,489	114,735	113,286	111,880	110,561

See end of table for Notes and Sources.

Table ES. Electric Power Industry - Summary Statistics for the United States, 1990 through 2001 (Continued)

Description	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Retail Sales and Revenue Data – Bundled and Unbundled (Continued)												
Sales to Ultimate Customers (thousand megawatthours)												
Residential	1,202,647	1,192,446	1,144,923	1,130,109	1,075,880	1,082,512	1,042,501	1,008,482	994,781	935,939	955,417	924,019
Commercial	1,089,154	1,055,232	1,001,996	979,401	928,633	887,445	862,685	820,269	794,573	761,271	765,664	751,027
Industrial	964,224	1,064,239	1,058,217	1,051,203	1,038,197	1,033,631	1,012,693	1,007,981	977,164	972,714	946,583	945,522
Other	113,756	109,496	106,952	103,518	102,901	97,539	95,407	97,830	94,944	93,442	94,339	91,988
All Sectors	3,369,782	3,421,414	3,312,087	3,264,231	3,145,610	3,101,127	3,013,287	2,934,563	2,861,462	2,763,365	2,762,003	2,712,555
Revenue From Ultimate Customers (million dollars)												
Residential	103,671	98,209	93,483	93,360	90,704	90,503	87,610	84,552	82,814	76,848	76,828	72,378
Commercial	86,354	78,405	72,771	72,575	70,497	67,829	66,365	63,396	61,521	58,343	57,655	55,117
Industrial	48,573	49,369	46,846	47,050	47,023	47,536	47,175	48,069	47,357	46,993	45,737	44,857
Other	7,999	7,179	6,796	6,863	7,110	6,741	6,567	6,689	6,528	6,296	6,138	5,891
All Sectors	246,597	233,163	219,896	219,848	215,334	212,609	207,717	202,706	198,220	188,480	186,359	178,243
Average Revenue per Kilowatthour (cents)												
Residential	8.62	8.24	8.16	8.26	8.43	8.36	8.40	8.38	8.32	8.21	8.04	7.83
Commercial	7.93	7.43	7.26	7.41	7.59	7.64	7.69	7.73	7.74	7.66	7.53	7.34
Industrial	5.04	4.64	4.43	4.48	4.53	4.60	4.66	4.77	4.85	4.83	4.83	4.74
Other	7.03	6.56	6.35	6.63	6.91	6.91	6.88	6.84	6.88	6.74	6.51	6.40
All Sectors	7.32	6.81	6.64	6.74	6.85	6.86	6.89	6.91	6.93	6.82	6.75	6.57
Revenue and Expense Statistics (Million dollars)[11]												
Major Investor Owned												
Utility Operating Revenues	267,525	235,336	214,160	218,175	215,083	207,459	199,967	196,282	193,638	185,493	182,451	173,000
Utility Operating Expenses	235,198	210,324	182,258	186,498	182,796	173,920	165,321	164,207	161,908	153,682	150,362	142,471
Net Utility Operating Income	32,327	25,012	31,902	31,677	32,286	33,539	34,646	32,074	31,730	31,811	32,089	30,529
Major Publicly Owned (with Generation Facilities)[12]												
Operating Revenues	38,028	31,843	26,767	26,155	25,397	24,207	23,473	23,267	22,522	21,686	21,083	20,470
Operating Expenses	32,811	26,244	21,274	20,880	20,425	19,084	18,959	18,649	18,162	17,191	16,887	16,461
Net Electric Operating Income	5,217	5,598	5,493	5,275	4,972	5,123	4,514	4,618	4,360	4,496	4,196	4,010
Major Publicly Owned (without Generation Facilities)[12]												
Operating Revenues	10,417	9,904	9,354	8,790	8,586	8,582	8,435	7,996	7,523	7,247	7,120	6,979
Operating Expenses	9,820	9,355	8,737	8,245	8,033	8,123	7,979	7,567	7,063	6,844	6,860	6,741
Net Electric Operating Income	597	549	617	545	552	459	457	429	460	404	260	238
Major Federally Owned												
Operating Revenues	12,136	10,685	10,186	9,780	8,833	9,082	8,743	8,552	8,141	7,872	8,194	8,197
Operating Expenses	9,785	8,139	7,775	7,099	5,999	6,390	6,162	6,303	6,056	5,883	5,288	5,428
Net Electric Operating Income	2,352	2,546	2,411	2,681	2,834	2,692	2,581	2,249	2,085	1,989	2,906	2,769
Major Cooperative Borrower Owned												
Operating Revenues	26,402	25,629	23,824	23,988	23,321	24,424	24,609	23,777	24,873	23,325	22,784	22,226
Operating Expenses	23,714	22,982	21,283	21,223	20,715	23,149	21,741	20,993	21,675	20,353	19,887	19,169
Net Electric Operating Income	2,688	2,647	2,541	2,764	2,606	2,872	2,868	2,784	3,197	2,973	2,897	3,057
Demand-Side Management (DSM) Data												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction[13]	24,955	22,901	26,455	27,231	25,284	29,893	29,561	25,001	23,069	17,204	15,619	13,704
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119	31,779	NA	NA
Load Management	1,816	875	872	392	953	1,989	2,093	2,763	4,175	4,114	NA	NA
DSM Cost (thousand dollars)												
Total Cost[14]	1,639,424	1,564,901	1,423,644	1,420,920	1,636,020	1,902,197	2,421,284	2,715,657	2,743,533	2,348,094	1,803,773	1,177,457

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 and hydroelectric pumped storage facility production minus energy used for pumping.
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.
7 Anthracite, bituminous coal, subbituminous coal, and lignite, excludes waste coal.
8 Alaska and Hawaii are not included.
9 The 2001 data for unregulated entities are not available.
10 Includes miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
11 Unless otherwise noted, all "dollars" are nominal dollars.
12 The 1998-2001 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 1990-1997 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 2 previous years.
13 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.
14 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 flows out to support demand-side management programs.

NA = Not available.

Notes: ·See Glossary 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;" Form EIA-412, "Annual Electric Industry Financial Report;" EIA-767, "Steam-Electric Plant Operation and Design Report;" Form EIA-860, " Annual Electric Generator Report;" Form EIA-861, "Annual Electric Power Industry Report;" Form EIA-906, "Power Plant Report;" 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 Cost and Quality of Fuels for Electric Plants Report," 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 - Natural Energy Board of Canada (metered energy firm and interruptible).

Chapter 1. Generation

Table 1.1. Net Generation by Energy Source by Type of Producer, 1990 through 2001

(Thousand Megawatthours)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Nuclear	Hydro-electric[4]	Other Renewables[5]	Other[6]	Total
Total Electric Power Industry									
1990	1,594,011	126,621	372,765	10,383	576,862	289,358	64,372	3,616	3,037,988
1991	1,590,623	119,752	381,553	11,336	612,565	284,453	68,779	4,739	3,073,799
1992	1,621,206	100,154	404,074	13,270	618,776	248,911	73,770	3,720	3,083,882
1993	1,690,070	112,788	414,927	12,956	610,291	276,458	76,213	3,487	3,197,191
1994	1,690,694	105,901	460,219	13,319	640,440	256,748	76,535	3,667	3,247,522
1995	1,709,426	74,554	496,058	13,870	673,402	308,108	73,965	4,104	3,353,487
1996	1,795,196	81,411	455,056	14,356	674,729	344,074	75,796	3,571	3,444,188
1997	1,845,016	92,555	479,399	13,351	628,644	352,413	77,183	3,612	3,492,172
1998	1,873,516	128,800	531,257	13,492	673,702	318,868	77,088	3,571	3,620,295
1999	1,881,087	118,061	556,396	14,126	728,254	313,439	79,423	4,024	3,694,810
2000	1,966,265	111,221	601,038	13,955	753,893	270,034	80,906	4,794	3,802,105
2001	1,903,380	127,629	629,201	13,767	768,826	207,548	78,916	4,254	3,733,521
Electricity Generators, Electric Utilities									
1990	1,559,606	117,017	264,089	0	576,862	279,926	10,651	0	2,808,151
1991	1,551,167	111,463	264,172	0	612,565	275,519	10,137	0	2,825,023
1992	1,575,895	88,916	263,872	0	618,776	239,559	10,200	0	2,797,219
1993	1,639,151	99,539	258,915	0	610,291	265,063	9,565	0	2,882,525
1994	1,635,493	91,039	291,115	0	640,440	243,693	8,933	0	2,910,712
1995	1,652,914	60,844	307,306	0	673,402	293,653	6,409	0	2,994,529
1996	1,737,453	67,346	262,730	0	674,729	327,970	7,214	0	3,077,442
1997	1,787,806	77,753	283,625	0	628,644	337,234	7,462	0	3,122,523
1998	1,807,480	110,158	309,222	0	673,702	304,403	7,206	0	3,212,171
1999	1,767,679	86,929	296,381	0	725,036	293,932	3,716	0	3,173,674
2000	1,696,619	72,180	290,715	0	705,433	248,195	2,241	0	3,015,383
2001	1,560,146	78,919	264,434	0	534,207	190,105	2,152	0	2,629,962
Electricity Generators, Independent Power Producers									
1990	556	553	589	*	--	6,319	23,878	--	31,895
1991	757	745	3,604	3	--	5,959	27,527	--	38,596
1992	1,165	1,160	6,999	3	--	6,280	30,228	--	45,836
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	--	8,997	34,703	--	91,455
1999	64,387	17,906	60,264	36	3,218	14,635	40,460	--	200,905
2000	213,956	25,795	108,712	181	48,460	17,604	42,831	--	457,540
2001	290,429	35,534	156,093	47	234,619	14,434	41,361	0	772,517
Combined Heat and Power, Electric Power[7]									
1990	11,947	1,294	44,808	621	--	--	2,593	12	61,275
1991	16,921	590	49,997	716	--	--	3,315	403	71,942
1992	20,653	2,162	63,403	1,209	--	--	3,411	480	91,319
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	31,087	6,785	125,380	2,410	--	--	4,376	113	170,151
Combined Heat and Power, Commercial[8]									
1990	796	589	3,272	121	--	138	922	--	5,837
1991	775	413	3,213	116	--	131	1,010	1	5,659
1992	749	302	3,867	105	--	122	1,082	1	6,228
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	978	427	4,492	*	--	66	1,480	*	7,443
Combined Heat and Power, Industrial[9]									
1990	21,107	7,169	60,007	9,641	--	2,975	26,328	3,604	130,830
1991	21,002	6,540	60,567	10,501	--	2,844	26,791	4,336	132,579
1992	22,743	7,615	65,933	11,953	--	2,950	28,847	3,239	143,280
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	20,740	5,964	78,802	11,310	--	2,943	29,548	4,141	153,448

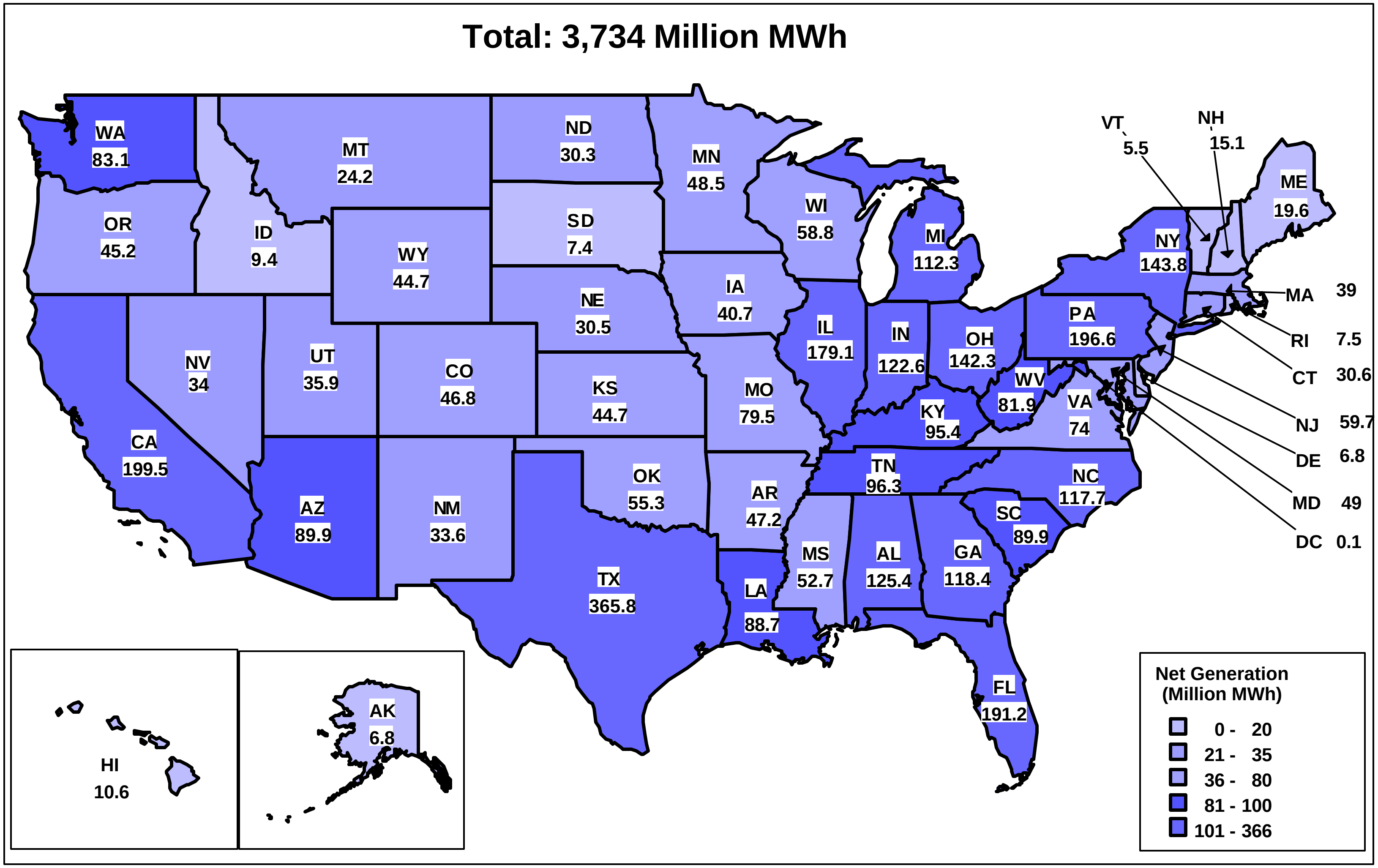
[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, 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 and hydroelectric pumped storage facility production minus energy used for pumping.
[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.
[7] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[8] Small number of commercial electricity-only plants included.
[9] Small number of Industrial electricity-only plants included.

* = For detailed data, the absolute value is less than 0.5, for percentage calculations, the absolute value is less than 0.05 percent.

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

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

Figure 1.1. U.S. Electric Power Industry Net Generation by State, 2001 (Million Megawatthours)



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

Table 1.2. Useful Thermal Output by Energy Source, by Combined Heat and Power Producers, 1990 through 2001
(Billion Btus)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Other Renewables[4]	Other[5]	Total
Total Combined Heat and Power							
1990	362,524	127,363	538,063	140,695	687,005	40,149	1,895,799
1991	351,834	112,144	546,755	148,216	660,091	44,331	1,863,371
1992	367,158	117,172	591,875	159,887	698,350	41,598	1,976,040
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	373,084	98,484	805,528	179,478	666,381	41,742	2,164,697
Combined Heat and Power, Electric Power[6]							
1990	20,793	9,029	79,905	3,822	24,509	28	138,086
1991	21,239	5,502	82,279	3,940	26,293	590	139,843
1992	27,545	6,123	101,923	4,825	24,861	1,543	166,820
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	55,131	5,029	161,236	7,833	20,997	36	250,262
Combined Heat and Power, Commercial[7]							
1990	14,670	5,406	15,515	118	10,580	--	46,289
1991	15,967	3,684	20,809	118	9,149	1	49,728
1992	15,311	3,964	24,298	93	13,511	1	57,178
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	0	18,057	0	73,474
1997	21,958	3,832	39,893	20	20,232	0	85,935
1998	20,185	4,853	38,510	34	18,426	--	82,008
1999	20,479	3,298	36,857	0	17,145	0	77,779
2000	21,001	3,827	39,293	0	17,613	0	81,734
2001	21,193	4,713	38,089	0	14,084	0	78,079
Combined Heat and Power, Industrial[8]							
1990	327,061	112,928	442,643	136,755	651,916	40,121	1,711,424
1991	314,628	102,958	443,667	144,158	624,649	43,740	1,673,800
1992	324,302	107,085	465,654	154,969	659,978	40,054	1,752,042
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	296,760	88,742	606,203	171,645	631,300	41,706	1,836,356

[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 biomas, geothermal, solar thermal, photovoltaic energy, and wind.
[5] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[6] Electric utility CHP plants are not included.
[7] Small number of commercial electricity-only plants included.
[8] Small number of industrial electricity-only plants included.

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

Chapter 2. Capacity

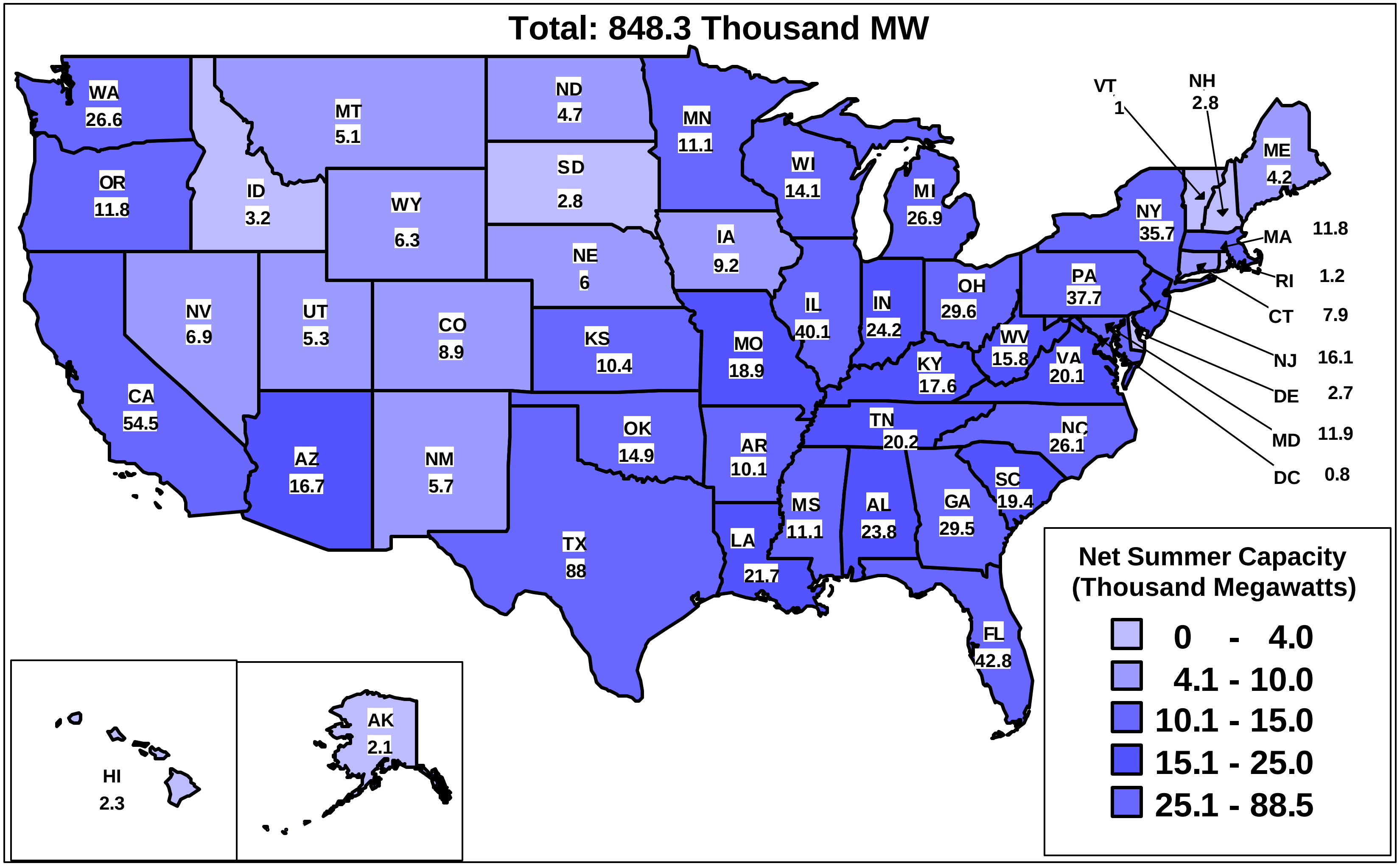
Table 2.1. Existing Net Summer Capacity by Energy Source and Producer Type, 1990 through 2001
(Megawatts)

Period	Coal[1]	Petroleum[2]	Natural Gas	Dual Fired	Other Gases[3]	Nuclear	Hydro-electric[4]	Other Renewables[5]	Other[6]	Total
Total Power Producers										
1990	307,361	48,994	56,194	113,582	1,641	99,624	93,385	12,840	501	734,122
1991	307,438	47,296	60,836	113,725	2,103	99,589	94,450	13,895	539	739,870
1992	309,372	45,642	60,736	118,913	2,069	98,985	95,962	14,281	545	746,507
1993	310,148	44,019	65,523	120,157	1,931	99,041	98,557	14,656	550	754,582
1994	311,415	42,695	70,685	123,110	2,093	99,148	99,249	15,021	550	763,967
1995	311,386	43,708	75,438	121,958	1,661	99,515	99,948	15,300	550	769,463
1996	313,382	43,585	74,498	128,570	1,664	100,784	97,548	15,309	550	775,890
1997	313,624	43,202	76,348	129,384	1,525	99,716	98,725	15,351	774	778,649
1998	315,786	40,399	75,772	130,399	1,520	97,070	98,669	15,444	810	775,868
1999	315,496	35,587	73,562	146,039	1,909	97,411	98,958	15,942	1,023	785,927
2000	315,114	35,890	95,705	149,833	2,342	97,860	98,881	15,572	523	811,719
2001	314,230	39,714	125,798	153,482	1,670	98,159	98,580	16,180	440	848,254
Electricity Generators, Electric Utilities										
1990	299,781	47,722	43,958	106,011	375	99,624	90,885	2,111	*	690,465
1991	299,444	45,931	48,280	105,019	692	99,589	92,031	2,031	--	693,016
1992	300,385	44,330	47,599	107,485	692	98,985	93,375	2,207	--	695,059
1993	300,634	42,699	49,709	109,066	698	99,041	95,910	2,215	--	699,971
1994	300,941	41,296	51,239	110,633	698	99,148	95,995	2,278	--	702,229
1995	300,569	42,232	55,220	109,294	291	99,515	96,661	2,330	--	706,111
1996	302,420	42,090	52,527	115,740	63	100,784	94,239	2,079	--	709,942
1997	302,866	41,545	53,552	116,174	206	99,716	95,487	2,123	222	711,889
1998	299,739	38,144	40,764	114,201	55	97,070	94,424	2,067	229	686,692
1999	277,780	31,742	31,755	108,716	220	95,030	93,067	790	224	639,324
2000	260,990	25,823	32,069	106,806	57	85,968	91,758	837	13	604,319
2001	244,451	24,150	35,117	92,030	57	63,060	90,065	979	13	549,920
Electricity Generators, Independent Power Producers										
1990	95	123	136	414	1	--	1,918	5,485	--	8,172
1991	173	89	115	1,076	1	--	1,824	6,092	--	9,369
1992	384	110	102	2,052	1	--	1,978	6,296	--	10,924
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	--	--	3,074	6,955	--	34,675
1999	27,725	2,502	18,024	26,534	--	2,381	4,763	8,794	--	90,724
2000	44,164	8,611	35,493	34,995	--	11,892	6,011	8,994	--	150,159
2001	60,785	13,919	58,995	56,326	--	35,099	7,445	9,743	--	242,314
Combined Heat and Power, Electric Power[7]										
1990	2,420	109	3,851	4,353	--	--	--	481	--	11,215
1991	2,864	344	4,455	4,795	--	--	--	474	--	12,932
1992	3,519	265	4,343	6,598	4	--	--	458	--	15,187
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	4,544	363	16,965	3,633	287	--	8	728	28	26,555
Combined Heat and Power, Commercial[8]										
1990	266	151	168	581	--	--	30	208	--	1,405
1991	232	106	155	576	--	--	30	238	--	1,339
1992	234	117	266	611	--	--	31	251	--	1,510
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	--	--	22	348	--	2,912
Combined Heat and Power, Industrial[9]										
1990	4,799	888	8,081	2,223	1,265	--	551	4,556	501	22,865
1991	4,725	826	7,831	2,259	1,410	--	565	5,060	539	23,214
1992	4,849	820	8,426	2,167	1,373	--	578	5,068	545	23,826
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

[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 and hydroelectric pumped storage facility production minus energy used for pumping.
[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.
[7] Electric utility CHP plants are included in Electric Generators, Electric Utilities.
[8] Small number of commercial electricity-only plants included.
[9] Small number of industrial electricity-only plants included.

* = For detailed data, the absolute value is less than 0.5, for percentage calculations, the absolute value is less than 0.05 percent.
Notes: ·See Glossary for definitions.·Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," and predecessor forms.

Figure 2.1 U.S. Electric Power Industry Existing Net Summer Capacity by State, 2001 (Thousand Megawatts)



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

Table 2.2. Existing Capacity by Energy Source, 2001
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Coal[1]	1,600	336,868	314,230	316,148
Petroleum[2]	2,967	44,626	39,714	43,670
Natural Gas	2,561	140,891	125,798	134,896
Dual Fired	2,886	170,444	153,482	162,903
Other Gases[3]	89	1,813	1,670	1,678
Nuclear	104	104,933	98,159	99,468
Hydroelectric[4]	4,143	95,844	98,580	98,397
Other Renewables[5]	1,497	18,133	16,180	16,737
Other[6]	18	573	440	440
Total	**15,865**	**914,124**	**848,254**	**874,338**

[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 and hydroelectric pumped storage facility production minus energy used for pumping.
[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 used in a plant, 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," and predecessor forms.

Table 2.3. Existing Capacity by Producer Type, 2001
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Electricity Generators				
Electricity Generators, Electric Utilities	8,798	584,574	549,920	561,382
Electricity Generators, Independent Power Producers	3,803	265,503	242,314	253,287
Electricity Generators, Total	**12,601**	**850,077**	**792,234**	**814,669**
Combined Heat and Power				
Combined Heat and Power, Electric Power	541	31,084	26,555	28,543
Combined Heat and Power, Commercial	626	3,463	2,912	3,179
Combined Heat and Power, Industrial	2,097	29,500	26,553	27,947
Combined Heat and Power, Total	**3,264**	**64,047**	**56,020**	**59,669**
Total Electric Power Sector	**15,865**	**914,124**	**848,254**	**874,338**

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

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

Table 2.4. Planned Nameplate Capacity Additions by Energy Source, 2002 through 2006
(Megawatts)

Energy Source	2002	2003	2004	2005	2006
Coal[1]	669	1,714	60	4,624	2,011
Petroleum[2]	1,119	356	1	213	386
Natural Gas	84,979	103,629	69,525	38,437	10,437
Other Gases[3]	205	--	--	580	580
Nuclear	--	--	--	--	--
Hydroelectric[4]	22	72	--	9	--
Other Renewables[5]	218	49	373	77	--
Other[6]	--	281	--	--	--
Total	**87,211**	**106,101**	**69,959**	**43,939**	**13,414**

[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 and hydroelectric pumped storage facility production minus energy used for pumping.
[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 used in a plant, 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," and predecessor forms.

Table 2.5. Planned Capacity Additions by Energy Source, 2002-2006
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
		2002		
U.S. Total	**836**	**87,211**	**80,249**	**83,917**
Coal[1]	3	669	595	595
Petroleum[2]	122	1,119	1,045	1,078
Natural Gas	644	84,979	78,225	81,839
Other Gases[3]	5	205	193	197
Nuclear	--	--	--	--
Hydroelectric[4]	9	22	22	22
Other Renewables[5]	53	218	170	186
Other[6]	--	--	--	--
		2003		
U.S. Total	**653**	**106,101**	**99,804**	**104,433**
Coal[1]	5	1,714	1,691	1,691
Petroleum[2]	29	356	335	341
Natural Gas	586	103,629	97,379	102,008
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric[4]	13	72	72	72
Other Renewables[5]	19	49	46	40
Other[6]	1	281	281	281
		2004		
U.S. Total	**405**	**69,959**	**64,400**	**67,868**
Coal[1]	1	60	60	60
Petroleum[2]	1	1	1	1
Natural Gas	397	69,525	63,967	67,435
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric[4]	--	--	--	--
Other Renewables[5]	6	373	372	372
Other[6]	--	--	--	--
		2005		
U.S. Total	**186**	**43,939**	**41,014**	**42,278**
Coal[1]	10	4,624	4,265	4,288
Petroleum[2]	2	213	173	202
Natural Gas	166	38,437	35,927	37,138
Other Gases[3]	2	580	580	580
Nuclear	--	--	--	--
Hydroelectric[4]	2	9	9	9
Other Renewables[5]	4	77	60	62
Other[7]	--	--	--	--
		2006		
U.S. Total	**54**	**13,414**	**11,946**	**12,584**
Coal[1]	4	2,011	1,882	1,882
Petroleum[2]	2	386	306	364
Natural Gas	45	10,437	9,178	9,758
Other Gases[3]	3	580	580	580
Nuclear	--	--	--	--
Hydroelectric[4]	--	--	--	--
Other Renewables[5]	--	--	--	--
Other[6]	--	--	--	--

[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 and hydroelectric pumped storage facility production minus energy used for pumping.
[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 used in a plant, 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," and predecessor forms.

Table 2.6. Capacity Additions and Retirements by Energy Source, 2001
(Megawatts)

Energy Source	Additions[1]				Retirements			
	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Coal[2]	--	--	--	--	9	52	48	62
Petroleum[3]	113	502	425	438	82	153	137	149
Natural Gas	313	30,211	25,638	28,467	20	336	290	318
Dual Fired	102	11,583	9,805	11,741	16	253	227	228
Other Gases[4]	--	--	--	--	1	10	9	9
Nuclear	--	--	--	--	--	--	--	--
Hydroelectric[5]	8	21	20	19	1	*	*	*
Other Renewables[6]	104	1,621	1,572	1,586	18	103	97	98
Other[7]	--	--	--	--	1	*	*	*
Total	**640**	**43,938**	**37,460**	**42,251**	**148**	**908**	**808**	**865**

[1] Generator re-ratings and revisions/corrections to previously reported data are not included.
[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] Conventional hydroelectric power and hydroelectric pumped storage facility production minus energy used for pumping.
[6] 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.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

* = For detailed data, the absolute value is less than 0.5, for percentage calculations, the absolute value is less than 0.05 percent.

Notes: ·Where there is more than one energy source used in a plant, 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," and predecessor forms.

Chapter 3. Demand, Capacity Resources, and Capacity Margins

Table 3.1. Noncoincident Peak Load, Actual and Projected by North American Electric Reliability Council Region, 1997 through 2006
(Megawatts)

North American Electric Reliability Council Region	Actual				
	1997	1998	1999	2000[R]	2001
Summer					
ECAR	93,492	93,784	99,239	92,033	100,235
ERCOT	50,541	54,666	55,529	57,606	55,201
FRCC	35,375	38,730	37,493	37,194	39,062
MAAC	49,464	48,445	51,645	49,477	54,015
MAIN	45,887	47,509	51,535	52,552	56,344
MAPP (U.S.)	29,787	30,722	31,903	28,605	28,321
NPCC (U.S.)	49,269	49,566	52,855	50,057	55,949
SERC	137,382	143,226	149,685 R	156,088	149,293
SPP	36,479	37,724	38,609	40,199	40,273
WSCC (U.S.)	110,001	115,921	113,629	114,602	109,119
Contiguous U.S.	**637,677**	**660,293**	**682,122 R**	**678,413**	**687,812**
Winter					
ECAR	75,670	84,401	86,239	84,546	85,485
ERCOT	37,966	41,876	39,164	44,641	44,015
FRCC	33,076	39,975	40,178	38,606	40,922
MAAC	37,217	36,532	40,220	43,256	39,458
MAIN	34,973	37,410	39,081	41,943	40,529
MAPP (U.S.)	25,390	26,080	25,200	24,536	21,815
NPCC (U.S.)	41,338	44,199 R	45,227	43,852	42,670
SERC	122,649	127,416	128,563	139,146	135,182
SPP	27,437	27,847	27,963	30,576	29,614
WSCC (U.S.)	94,158	101,822	99,080	97,324	96,622
Contiguous U.S.	**529,874**	**567,558**	**570,915**	**588,426**	**576,312**
North American Electric Reliability Council Region	**Projected**				
	2002	**2003**	**2004**	**2005**	**2006**
Summer					
ECAR	99,346	101,871	104,548	106,541	109,113
ERCOT	57,898	60,727	63,190	64,965	66,857
FRCC	40,145	41,335	42,292	43,279	44,274
MAAC	54,188	55,089	55,956	56,872	57,809
MAIN	56,888	57,693	58,575	59,753	60,799
MAPP (U.S.)	28,191	28,681	29,729	30,726	31,257
NPCC (U.S.)	54,675	55,813	56,531	57,198	57,903
SERC	160,384	164,001	167,879	171,439	174,795
SPP	41,483	42,490	43,556	44,678	45,197
WSCC (U.S.)	116,852	119,465	122,089	124,541	126,886
Contiguous U.S.	**710,050**	**727,165**	**744,345**	**759,992**	**774,890**
Winter					
ECAR	87,133	89,228	90,796	92,586	94,404
ERCOT	45,818	47,802	49,217	50,708	52,193
FRCC	43,199	44,219	45,237	46,242	47,215
MAAC	44,747	45,367	46,019	46,668	47,288
MAIN	43,028	43,750	43,935	44,740	45,264
MAPP (U.S.)	23,234	23,654	24,323	24,702	25,167
NPCC (U.S.)	45,308	45,943	46,447	46,995	47,489
SERC	139,527	142,730	146,754	148,624	151,445
SPP	30,382	30,743	31,761	32,464	32,732
WSCC (U.S.)	103,314	105,611	107,953	110,023	112,384
Contiguous U.S.	**605,690**	**619,047**	**632,442**	**643,752**	**655,581**

R = Revised.

Notes: ·Actual data are final.·Projected data are updated annually.·NERC Regional Council names may be found in the Glossary.·In 1998, several utilities realigned from SPP to SERC.·On January 1, 1997, FRCC became the tenth NERC region, separating from 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.·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, 1990 through 2001

(Megawatts)

Region and Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
ECAR												
Net Internal Demand	100,235	98,651	94,072	92,359	91,103	88,573	85,643	84,967	83,530	80,536	79,948	79,370
Capacity Resources	113,136	115,379	107,451	105,545	105,106	104,953	103,003	101,605	101,910	100,027	98,993	97,588
Capacity Margin (percent)	11.4	14.5	12.5	12.5	13.3	15.6	16.9	16.4	18.0	19.5	19.2	18.7
ERCOT												
Net Internal Demand	55,106	53,649	51,697	50,254	47,746	45,636	44,990	43,630	42,629	43,093	43,516	41,915
Capacity Resources	70,797	69,622	65,423	59,788	55,771	55,230	55,074	54,219	54,323	54,994	53,954	53,549
Capacity Margin (percent)	22.2	22.9	21.0	15.9	14.4	17.4	18.3	19.5	21.5	21.6	19.3	21.7
FRCC												
Net Internal Demand	38,932	35,666	34,832	34,562	32,874	31,868	31,649 R	30,537	29,435	28,898	27,773	27,162
Capacity Resources	42,290	43,083	40,645	39,708	39,613	38,237	38,282 R	37,577	36,225	34,565	33,669	33,964
Capacity Margin (percent)	7.9	17.2	14.3	13.0	17.0	16.7	17.3 R	18.7	18.7	16.4	17.5	20.0
MAAC												
Net Internal Demand	54,015	51,358	49,325	47,626	46,548	45,628	45,224	44,571	44,198	44,348	43,794	43,341
Capacity Resources	59,533	60,679	57,831	55,511	56,155	56,774	56,881	56,271	55,328	55,272	55,347	54,132
Capacity Margin (percent)	9.3	15.4	14.7	14.2	17.1	19.6	20.5	20.8	20.1	19.8	20.9	19.9
MAIN												
Net Internal Demand	53,032	51,845	47,165	45,570	45,194	44,470	43,229	42,611	42,001	41,304	41,083	40,466
Capacity Resources	65,950	64,170	55,984	52,722	52,160	52,880	52,112	50,963	50,333	49,104	48,471	48,244
Capacity Margin (percent)	19.6	19.2	15.8	13.6	13.4	15.9	17.0	16.4	16.6	15.9	15.2	16.1
MAPP (U.S.)												
Net Internal Demand	27,125	28,006	30,606	29,766	28,221	27,298	27,487	26,855	25,901	26,050	26,168	24,055
Capacity Resources	32,271	34,236	35,373	34,773	34,027	33,121	32,665	32,267	31,964	32,411	31,975	32,063
Capacity Margin (percent)	15.9	18.2	13.5	14.4	17.1	17.6	15.9	16.8	19.0	19.6	18.2	25.0
NPCC (U.S.)												
Net Internal Demand	55,888	54,270	53,450	51,760	50,240	48,950	48,290	47,465	46,380	46,007	45,952	46,016
Capacity Resources	63,760	63,376	63,077	60,439	60,729	58,592	62,368	61,906	62,049	61,960	59,972	60,878
Capacity Margin (percent)	12.3	14.4	15.3	14.4	17.3	16.5	22.6	23.3	25.3	25.7	23.4	24.4
SERC												
Net Internal Demand	144,399	151,527	142,726 R	138,146	134,968	109,270	105,785 R	101,885	99,287	97,448	94,767	93,893
Capacity Resources	171,530	169,760	160,575 R	158,360	155,016	126,196	127,562 R	120,044	117,375	115,635	114,690	112,112
Capacity Margin (percent)	15.8	10.7	11.1 R	12.8	12.9	13.4	17.1	15.1	15.4	15.7	17.4	16.3
SPP												
Net Internal Demand	38,807	39,056	37,807	36,402	37,009	59,017	57,951	56,395	55,067	52,183	51,537	51,554
Capacity Resources	45,530	46,109	43,111	42,554	43,591	69,344	69,354	69,198	67,922	67,472	67,472	67,333
Capacity Margin (percent)	14.8	15.3	12.3	14.5	15.1	14.9	16.4	18.5	18.9	22.7	23.6	23.4
WSCC (U.S.)												
Net Internal Demand	107,294	116,913	112,177	111,641	104,486	101,728	99,612	99,724	96,613	94,595	93,408	91,052
Capacity Resources	124,193	141,640	136,274	135,270	135,687	135,049	130,180	127,533	127,931	125,992	127,794	127,478
Capacity Margin (percent)	13.6	17.5	17.7	17.5	23.0	24.7	23.5	21.8	24.5	24.9	26.9	28.6
Contiguous U.S.												
Net Internal Demand	**674,833**	**680,941**	**653,857 R**	**638,086**	**618,389**	**602,438**	**589,860**	**578,640**	**565,041**	**554,462**	**547,946**	**538,824**
Capacity Resources	**788,990**	**808,054**	**765,744 R**	**744,670**	**737,855**	**730,376**	**727,481**	**711,583**	**705,360**	**697,432**	**692,337**	**687,341**
Capacity Margin (percent)	**14.5**	**15.7**	**14.6**	**14.3**	**16.2**	**17.5**	**18.9**	**18.7**	**19.9**	**20.5**	**20.9**	**21.6**

R = Revised.

Notes: ·NERC Regional Council names may be found in the Glossary.·In 1998, several utilities realigned from SPP to SERC.·On January 1, 1997, FRCC became the tenth NERC region, separating from 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, 2001 through 2006

(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand	Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Capacity Resources	Capacity Margin (percent)
	2001			2002		
ECAR	100,235	113,136	11.4	96,328	122,995	21.7
ERCOT	55,106	70,797	22.2	57,736	76,482	24.5
FRCC	38,932	42,290	7.9	37,400	44,735	16.4
MAAC	54,015	59,533	9.3	52,569	64,003	17.9
MAIN	53,032	65,950	19.6	53,352	70,842	24.7
MAPP (U.S.)	27,125	32,271	15.9	26,490	32,967	19.6
NPCC (U.S.)	55,888	63,760	12.3	54,617	67,992	19.7
SERC	144,399	171,530	15.8	154,289	176,456	12.6
SPP	38,807	45,530	14.8	39,942	47,591	16.1
WSCC (U.S.)	107,294	124,193	13.6	115,132	142,880	19.4
Contiguous U.S.	**674,833**	**788,990**	**14.5**	**687,855**	**846,943**	**18.8**
	2003			2004		
ECAR	98,795	139,170	29.0	101,436	151,831	33.2
ERCOT	60,565	80,150	24.4	63,028	82,649	23.7
FRCC	38,605	47,112	18.1	39,569	48,828	19.0
MAAC	53,470	68,167	21.6	54,337	73,421	26.0
MAIN	54,361	73,316	25.9	55,288	76,505	27.7
MAPP (U.S.)	27,312	33,297	18.0	28,355	32,185	11.9
NPCC (U.S.)	55,755	71,207	21.7	56,474	76,745	26.4
SERC	157,884	180,296	12.4	162,185	184,382	12.0
SPP	40,820	48,737	16.2	41,880	49,062	14.6
WSCC (U.S.)	117,744	156,554	24.8	120,334	176,571	31.8
Contiguous U.S.	**705,311**	**898,006**	**21.5**	**722,886**	**952,179**	**24.1**
	2005			2006		
ECAR	103,428	154,974	33.3	106,012	155,274	31.7
ERCOT	64,803	82,423	21.4	66,695	81,847	18.5
FRCC	40,559	49,982	18.9	41,561	50,375	17.5
MAAC	55,253	73,421	24.7	56,190	72,971	23.0
MAIN	56,466	76,975	26.6	57,503	76,930	25.3
MAPP (U.S.)	29,348	32,051	8.4	29,876	32,372	7.7
NPCC (U.S.)	57,139	77,593	26.4	57,842	77,540	25.4
SERC	165,753	187,737	11.7	169,103	192,112	12.0
SPP	42,915	49,128	12.6	43,428	49,458	12.2
WSCC (U.S.)	122,789	196,618	37.5	125,133	204,966	38.9
Contiguous U.S.	**738,453**	**980,902**	**24.7**	**753,343**	**993,845**	**24.2**

Notes: ·Data are projected and updated annually.·NERC Regional Council names may be found in the Glossary.·In 1998, several utilities realigned from SPP to SERC.·On January 1, 1997, FRCC became the tenth NERC region, separating from 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 3.4. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Winter, 2001 through 2006
(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand	Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Capacity Resources	Capacity Margin (percent)
	2001/ 2002			2002/ 2003		
ECAR	82,831	115,926	28.5	84,474	125,251	32.6
ERCOT	43,908	72,644	39.6	45,656	80,426	43.2
FRCC	39,699	44,336	10.5	39,565	49,165	19.5
MAAC	39,458	63,604	38.0	44,048	65,871	33.1
MAIN	38,412	63,209	39.2	40,628	67,780	40.1
MAPP (U.S.)	21,575	30,809	30.0	22,689	31,878	28.8
NPCC (U.S.)	42,551	66,314	35.8	45,194	73,071	38.2
SERC	130,311	169,580	23.2	134,614	176,653	23.8
SPP	28,571	45,290	36.9	29,441	47,267	37.7
WSCC (U.S.)	95,395	119,254	20.0	101,865	144,664	29.6
Contiguous U.S.	**562,711**	**790,966**	**28.9**	**588,174**	**862,026**	**31.8**
	2003/ 2004			2004/ 2005		
ECAR	86,608	141,808	38.9	88,213	154,469	42.9
ERCOT	47,640	83,012	42.6	49,055	85,085	42.3
FRCC	40,588	51,312	20.9	41,596	51,375	19.0
MAAC	44,668	74,594	40.1	45,320	74,898	39.5
MAIN	41,327	71,972	42.6	42,271	74,608	43.3
MAPP (U.S.)	23,098	32,633	29.2	23,758	32,259	26.4
NPCC (U.S.)	45,821	75,528	39.3	46,306	81,740	43.3
SERC	137,804	180,275	23.6	141,812	184,540	23.2
SPP	29,679	48,325	38.6	30,697	48,444	36.6
WSCC (U.S.)	104,141	166,052	37.3	106,481	187,760	43.3
Contiguous U.S.	**601,374**	**925,511**	**35.0**	**615,509**	**975,178**	**36.9**
	2005/ 2006			2006/ 2007		
ECAR	90,040	157,612	42.9	91,930	157,912	41.8
ERCOT	50,546	84,508	40.2	52,031	83,525	37.7
FRCC	42,588	53,758	20.8	43,548	53,671	18.9
MAAC	45,969	74,898	38.6	46,589	74,898	37.8
MAIN	43,086	75,629	43.0	43,604	74,976	41.8
MAPP (U.S.)	24,125	32,115	24.9	24,604	32,352	23.9
NPCC (U.S.)	46,811	81,644	42.7	47,305	81,678	42.1
SERC	143,667	185,577	22.6	146,472	188,393	22.3
SPP	31,320	49,068	36.2	31,588	49,206	35.8
WSCC (U.S.)	108,547	200,780	45.9	110,908	201,622	45.0
Contiguous U.S.	**626,699**	**995,589**	**37.1**	**638,579**	**998,233**	**36.0**

Notes: ·Actual data are final.·Projected data are updated annually.·NERC Regional Council names may be found in the Glossary.·In 1998, several utilities realigned from SPP to SERC.·On January 1, 1997, FRCC became the tenth NERC region, separating from 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.·The winter peak period begins on December 1 and extends through March 31 of the following year. For example, winter 2001/2002 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".

Chapter 4. Fuel

Table 4.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1990 through 2001

Type of Power Producer and Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Thousand Mcf)[3]
Total				
1990	792,457	218,997	3,691,563	632,328
1991	793,666	203,669	3,764,778	616,179
1992	805,140	172,241	3,899,718	716,587
1993	842,153	192,462	3,928,653	758,648
1994	848,796	183,618	4,367,148	727,389
1995	860,594	132,578	4,737,871	844,741
1996	907,209	144,626	4,312,458	998,556
1997	931,949	159,715	4,564,770	519,581
1998	946,295	222,640	5,081,384	503,292
1999	949,802	207,871	5,321,984	600,070
2000	994,933	195,228	5,691,481	551,355
2001	973,076	222,294	5,768,117	515,707
Electricity Generators, Electric Utilities				
1990	773,549	200,152	2,787,332	0
1991	772,268	188,494	2,789,014	0
1992	779,860	152,329	2,765,608	0
1993	813,508	168,556	2,682,440	0
1994	817,270	155,377	2,987,146	0
1995	829,007	105,956	3,196,507	0
1996	874,681	116,680	2,732,107	0
1997	900,361	132,147	2,968,453	0
1998	910,867	187,461	3,258,054	0
1999	894,120	151,868	3,113,419	0
2000	859,335	125,788	3,043,094	0
2001	806,269	133,475	2,686,287	0
Electricity Generators, Independent Power Producers				
1990	664	1,094	6,778	6
1991	915	1,403	33,144	22
1992	1,326	2,099	63,389	16
1993	3,050	1,965	72,653	43
1994	3,939	1,998	77,414	43
1995	3,921	2,342	91,064	40
1996	4,143	2,169	91,617	32
1997	3,884	4,010	70,774	25
1998	9,486	9,676	285,878	1,489
1999	30,572	30,037	615,756	433
2000	107,745	45,011	1,049,636	1,320
2001	140,453	64,237	1,439,780	329
Combined Heat and Power, Electric Power[4]				
1990	7,088	3,499	353,179	55,954
1991	9,470	912	393,898	59,451
1992	12,204	3,291	495,967	84,115
1993	13,293	8,513	589,147	104,664
1994	14,904	12,011	693,923	90,594
1995	14,926	11,366	806,202	123,825
1996	15,575	11,320	836,086	115,579
1997	14,764	11,046	863,968	15,288
1998	13,773	12,310	871,881	34,115
1999	13,197	12,440	914,600	22,300
2000	15,634	13,147	921,341	43,692
2001	15,225	12,420	965,359	108,918
Combined Heat and Power, Commercial[5]				
1990	417	953	27,544	1,932
1991	403	576	26,806	1,884
1992	371	429	32,674	1,836
1993	404	672	37,435	1,752
1994	404	694	40,828	1,842
1995	569	649	42,700	--
1996	656	645	42,380	*
1997	630	790	38,975	9
1998	440	802	40,693	21
1999	481	931	39,045	*
2000	514	823	37,029	*
2001	473	869	37,090	*
Combined Heat and Power, Industrial[6]				
1990	10,740	13,299	516,729	574,436
1991	10,610	12,283	521,916	554,822
1992	11,379	14,093	542,081	630,619
1993	11,898	12,755	546,978	652,189
1994	12,279	13,537	567,836	634,910
1995	12,171	12,265	601,397	720,876
1996	12,153	13,813	610,268	882,944
1997	12,311	11,723	622,599	504,259
1998	11,728	12,392	624,878	467,666
1999	11,432	12,595	639,165	577,336
2000	11,706	10,459	640,381	506,344
2001	10,654	11,294	639,602	406,461

[1] Anthracite, bituminous coal, subbituminous coal, lignite, synthetic coal, and waste coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] 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.

* = For detailed data, the absolute value is less than 0.5, for percentage calculations, the absolute value is less than 0.05 percent.
Notes: ·See Glossary for definitions.·Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-906, "Power Plant Report," and predecessor forms.

Table 4.2. Consumption of Fossil Fuels for Useful Thermal Output by Type of Combined Heat and Power Producer, 1990 through 2001

Type of Power Producer and Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Thousand Mcf)[3]
Total				
1990	19,081	26,002	654,749	809,773
1991	18,458	23,039	663,963	750,704
1992	19,372	24,077	717,860	849,446
1993	19,750	26,394	733,584	831,806
1994	20,609	27,929	784,015	793,898
1995	20,418	25,562	834,382	654,799
1996	20,806	27,873	865,774	809,558
1997	21,005	28,802	868,569	839,718
1998	20,320	28,845	949,106	841,769
1999	20,373	26,822	982,958	873,137
2000	20,466	22,266	985,263	902,345
2001	19,949	20,379	977,823	663,977
Electric Power[4]				
1990	1,266	1,805	97,330	51,551
1991	1,221	1,101	99,868	59,243
1992	1,704	1,229	122,908	48,716
1993	1,794	1,591	128,743	33,074
1994	2,241	1,791	144,062	59,648
1995	2,376	2,784	142,753	38,671
1996	2,520	2,424	147,091	38,835
1997	2,355	2,466	161,608	11,079
1998	2,493	1,322	172,471	10,494
1999	3,033	1,423	175,757	7,280
2000	3,107	1,412	192,253	27,549
2001	3,128	1,082	196,548	50,348
Commercial				
1990	773	1,104	18,913	235
1991	826	761	25,295	233
1992	804	807	29,672	185
1993	968	843	27,738	234
1994	940	931	31,457	339
1995	850	596	34,964	--
1996	1,005	601	40,075	*
1997	1,108	794	47,941	10
1998	1,002	1,006	46,527	17
1999	1,009	682	44,991	*
2000	1,034	792	47,844	*
2001	1,038	985	46,133	*
Industrial				
1990	17,041	23,093	538,506	757,987
1991	16,412	21,177	538,800	691,229
1992	16,864	22,041	565,279	800,544
1993	16,988	23,960	577,103	798,497
1994	17,428	25,207	608,496	733,911
1995	17,192	22,182	656,665	616,128
1996	17,281	24,848	678,608	770,723
1997	17,542	25,541	659,021	828,629
1998	16,824	26,518	730,108	831,258
1999	16,330	24,718	762,210	865,858
2000	16,325	20,062	745,165	874,796
2001	15,783	18,312	735,142	613,629

[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] Electric utility CHP plants are included in Table 4.1 with Electric Generators, Electric Utilities.

* = For detailed data, the absolute value is less than 0.5, for percentage calculations, the absolute value is less than 0.05 percent.
Notes: ·See Glossary for definitions.·Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-906, "Power Plant Report," and predecessor forms.

Table 4.3. Consumption of Fossil Fuels for Electricity Generation and for Useful Thermal Output, 1990 through 2001

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Thousand Mcf)[3]
Total				
1990	811,538	244,998	4,346,311	1,442,101
1991	812,124	226,708	4,428,742	1,366,884
1992	824,512	196,318	4,617,578	1,566,033
1993	861,904	218,855	4,662,236	1,590,454
1994	869,405	211,547	5,151,163	1,521,287
1995	881,012	158,140	5,572,253	1,499,540
1996	928,015	172,499	5,178,232	1,808,114
1997	952,955	188,517	5,433,338	1,359,299
1998	966,615	251,486	6,030,490	1,345,061
1999	970,175	234,694	6,304,942	1,473,207
2000	1,015,398	217,494	6,676,744	1,453,701
2001	993,025	242,673	6,745,940	1,179,685

[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.

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

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

Table 4.4. End-of-Year Stocks of Coal and Petroleum, by Type of Producer, 1990 through 2001

Period	Electric Power Industry		Electricity Generators			
			Electric Utilities		Independent Power Producers	
	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)
1990	156,166	83,970	156,166	83,970	NA	NA
1991	157,876	75,343	157,876	75,343	NA	NA
1992	154,130	72,183	154,130	72,183	NA	NA
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	142,846	55,254	129,041	46,169	11,058	7,322
2000	103,440	41,956	90,115	30,502	10,477	9,803
2001	140,583	59,214	117,150	37,392	19,542	18,171

Period	Combined Heat and Power[3]					
	Electric Power		Commercial		Industrial	
	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)
1990	NA	NA	NA	NA	NA	NA
1991	NA	NA	NA	NA	NA	NA
1992	NA	NA	NA	NA	NA	NA
1993	NA	NA	NA	NA	NA	NA
1994	NA	NA	NA	NA	NA	NA
1995	NA	NA	NA	NA	NA	NA
1996	NA	NA	NA	NA	NA	NA
1997	NA	NA	NA	NA	NA	NA
1998	NA	NA	NA	NA	NA	NA
1999	1,505	618	54	162	1,188	984
2000	1,703	627	18	63	1,126	961
2001	1,817	1,308	165	404	1,908	1,940

[1] Anthracite, bituminous coal, subbituminous coal, and lignite, excludes waste coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] This category includes stocks for both electricity generation and for useful thermal output.

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.

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

Table 4.5. Receipts, Average Cost, and Quality of Fossil Fuels at Electric Utilities, 1990 through 2001

Period	Coal[1]				Petroleum[2]				Natural Gas		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)
1990	786,627	145.5	30.45	1.35	212,118	335.3	21.06	1.02	2,490,979	232.1	168.8
1991	769,923	144.7	30.02	1.30	172,051	252.7	15.93	1.11	2,630,818	215.3	160.2
1992	775,963	141.2	29.36	1.29	147,825	251.4	15.87	1.19	2,637,678	232.8	158.9
1993	769,152	138.5	28.58	1.18	154,144	237.3	14.95	1.32	2,574,523	256.0	159.4
1994	831,929	135.5	28.03	1.17	149,258	242.3	15.19	1.21	2,863,904	223.0	152.5
1995	826,860	131.8	27.01	1.08	89,908	256.6	16.10	1.18	3,023,327	198.4	145.2
1996	862,701	128.9	26.45	1.10	113,678	302.6	18.98	1.24	2,604,663	264.1	151.8
1997	880,588	127.3	26.16	1.11	128,749	273.0	17.18	1.35	2,764,734	276.0	152.0
1998	929,448	125.2	25.64	1.06	181,276	202.1	12.71	1.46	2,922,957	238.1	143.5
1999	908,232	121.6	24.72	1.01	145,939	235.9	14.81	1.47	2,809,455	257.4	143.8
2000	790,274	120.0	24.28	.93	108,272	417.9	26.30	1.31	2,629,986	430.2	173.5
2001	762,815	123.1	24.68	.89	124,618	369.3	23.20	1.40	2,152,366	448.6	173.0

[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.

Notes: ·Totals may not equal sum of components because of independent rounding.·As of 1991, data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.·Data for 1990 are for steam-electric plants with a generator nameplate capacity of 50 or more megawatts.·Mcf = thousand cubic feet.·Monetary values are expressed in nominal terms.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Cost and Quality of Fuels for Electric Plants Report."

Table 4.6. Receipts and Quality of Coal Delivered to Electric Utilities, 1990 through 2001
(Thousand Tons)

Period	Anthracite			Bituminous			Subbituminous			Lignite		
	Receipts	Sulfur percent by weight	Ash percent by weight	Receipts	Sulfur percent by weight	Ash percent by weight	Receipts	Sulfur percent by weight	Ash percent by weight	Receipts	Sulfur percent by weight	Ash percent by weight
1990	753	.71	32.7	477,782	1.86	10.5	232,660	.43	7.2	75,432	.92	14.0
1991	723	.64	33.4	450,462	1.84	10.3	239,929	.42	6.9	78,810	.95	14.9
1992	503	.67	32.0	453,732	1.81	10.2	241,291	.43	7.0	80,438	.97	14.6
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

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

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Cost and Quality of Fuels for Electric Plants Report."

Table 4.7. Average Quality of Fossil Fuels Burned at Electricity Generators, 1990 through 2001
(Thousand Tons)

Year	Coal[1]			Petroleum[2]		Natural Gas
	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
1990	10,465	1.35	9.85	149,682	.97	1,027
1991	10,378	1.30	9.76	150,282	1.06	1,024
1992	10,395	1.29	9.71	150,630	1.12	1,024
1993	10,315	1.18	9.55	150,685	1.22	1,023
1994	10,338	1.17	9.36	150,033	1.10	1,023
1995	10,248	1.08	9.23	150,207	1.00	1,019
1996	10,263	1.10	9.22	150,234	1.07	1,017
1997	10,275	1.11	9.36	151,007	1.12	1,019
1998	10,241	1.06	9.18	150,780	1.21	1,022
1999	10,163	1.01	9.01	150,700	1.18	1,019
2000	10,115	.93	8.84	150,817	1.07	1,020
2001	10,019	.89	8.75	150,673	1.16	1,027

[1] Anthracite, bituminous coal, subbituminous coal, lignite coal, synthetic fuel, and waste coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.

Note: Totals may not equal sum of components because of independent rounding.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Cost and Quality of Fuels for Electric Plants Report," and predecessor forms.

Chapter 5. Emissions

Table 5.1. Emissions, 1990 through 2001
(Thousand Metric Tons)

Emission	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Carbon Dioxide (CO_2)	2,290,045	2,327,868	2,222,525	2,209,983	2,123,263	2,058,980	1,985,162	1,970,581	1,945,346	1,865,680	1,851,086	1,853,975
Sulfur Dioxide (SO_2)	13,038	10,678	11,791	12,534	12,484	12,125	11,469	13,721	14,246	14,337	14,604	14,779
Nitrogen Oxides (NO_x)	6,118	5,191	5,549	5,999	6,085	6,137	5,908	6,732	6,927	6,717	6,816	6,887

Note: 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;" Form EIA-906, "Power Plant Report;" and predecesor forms. Nitrogen oxides adjusted by the Environmental Protection Agency's Continuous Emission Monitoring System.

Table 5.2. Number and Capacity of Fossil-Fueled Steam-Electric Generators with Environmental Equipment, 1990 through 2001

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)
1990	153	69,122	1,177	349,319	478	162,557	1,360	376,894
1991	155	70,734	1,173	352,910	485	164,632	1,353	378,883
1992	155	71,531	1,168	353,365	484	165,030	1,345	379,034
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	266	99,417	1,043	295,008	609	180,634	1,934	478,134

[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 and not all have environmental equipment.
[3] Nameplate capacity

Notes: ·These data are for plants with a fossil-fueled steam-electric capacity of 100 megawatts or more .·In 2001, data for plants with combustible renewable steam-electric capacity of 100 megawatts or more 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." Unregulated data are included beginning with 2001 data.

Table 5.3. Average Flue Gas Desulfurization Costs, 1990 through 2001

Year[1]	Average Overhead & Maintenance Costs (mills per kilowatthour)[2]	Average Installed Capital Costs (dollars per kilowatt)
1990	1.35	118.00
1991	1.40	130.00
1992	1.32	132.00
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	.92	112.00

[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.·In 2001, data for plants with combustible renewable steam-electric capacity of 100 megawatts or more 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." Unregulated data are included beginning with 2001 data.

Chapter 6. Trade

Table 6.1. Electric Power Industry - Purchases, 1990 through 2001
(Million Kilowatthours)

	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
U.S. Total	**2,976,254**	**2,345,540**	**2,039,969**	**2,020,622**	**1,966,447**	**1,797,720**	**1,617,715**	**1,528,222**	**1,492,370**	**1,395,789**	**1,340,593**	**1,191,222**
Electric Utilities	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	1,312,605	1,267,106	1,114,590
IPP and CHP[1]	NA	95,158	90,395	93,423[R]	88,348[R]	103,528[R]	89,647[R]	92,631[R]	84,951[R]	83,184[R]	73,487[R]	76,632[R]

[1] IPP are independent power producers and CHP are combined heat and power producers.

NA = Not available.

R = Revised.

Notes: ·Restructuring of the electric power industry has dramatically increased trade in various locations.·See Glossary 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," and predecessor forms.

Table 6.2. Electric Power Industry - Sales for Resale, 1990 through 2001
(Million Kilowatthours)

	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
U.S. Total	**2,081,384**	**2,325,652**	**1,977,753**	**1,914,916**	**1,838,539**	**1,656,090**	**1,495,015**	**1,387,966**	**1,387,137**	**1,284,273**	**1,250,314**	**1,115,946**
Electric Utilities	2,081,384	1,715,582	1,635,614	1,664,081	1,616,318	1,431,179	1,276,356[R]	1,185,352	1,200,047	1,119,948	1,116,655	999,268
IPP and CHP[1]	NA	610,069	342,138	250,835	222,221	224,911	218,660	202,614	187,090	164,324	133,659	116,677

[1] IPP are independent power producers and CHP are combined heat and power producers.

NA = Not available.

R = Revised.

Notes: ·Restructuring of the electric power industry has dramatically increased trade in various locations.·See Glossary 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," and predecessor forms.

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1990 through 2001
(Megawatthours)

Description	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
International Imports and Exports												
Canada												
Imports	38,379,753	48,801,972	42,619,118	39,513,588	43,008,951	42,233,376	40,596,119	44,821,858	29,364,197	26,224,179	19,815,290	16,494,107
Exports	17,805,808	12,684,706	12,731,850	11,255,694	7,470,332	1,986,361	2,468,244	941,214	2,691,723	1,836,692	1,687,950	15,543,122
Mexico[1]												
Imports[2]	98,645	76,800	303,439	11,249	22,279	1,263,152	2,257,411	2,011,319	1,993,328	2,022,419	2,115,739	1,951,288
Exports	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	989,887	616,628	590,462
Total Imports	**38,478,398**	**48,878,772**	**42,922,557**	**39,524,837**	**43,031,230**	**43,496,528**	**42,853,530**	**46,833,177**	**31,357,525**	**28,246,598**	**21,931,029**	**18,445,395**
Total Exports	**18,173,488**	**14,829,382**	**14,000,134**	**13,228,897**	**8,974,039**	**3,301,986**	**3,622,665**	**2,009,882**	**3,540,890**	**2,826,579**	**2,304,578**	**16,133,584**

[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.

[2] 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 Revenues

Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1990 through 2001
(Number)

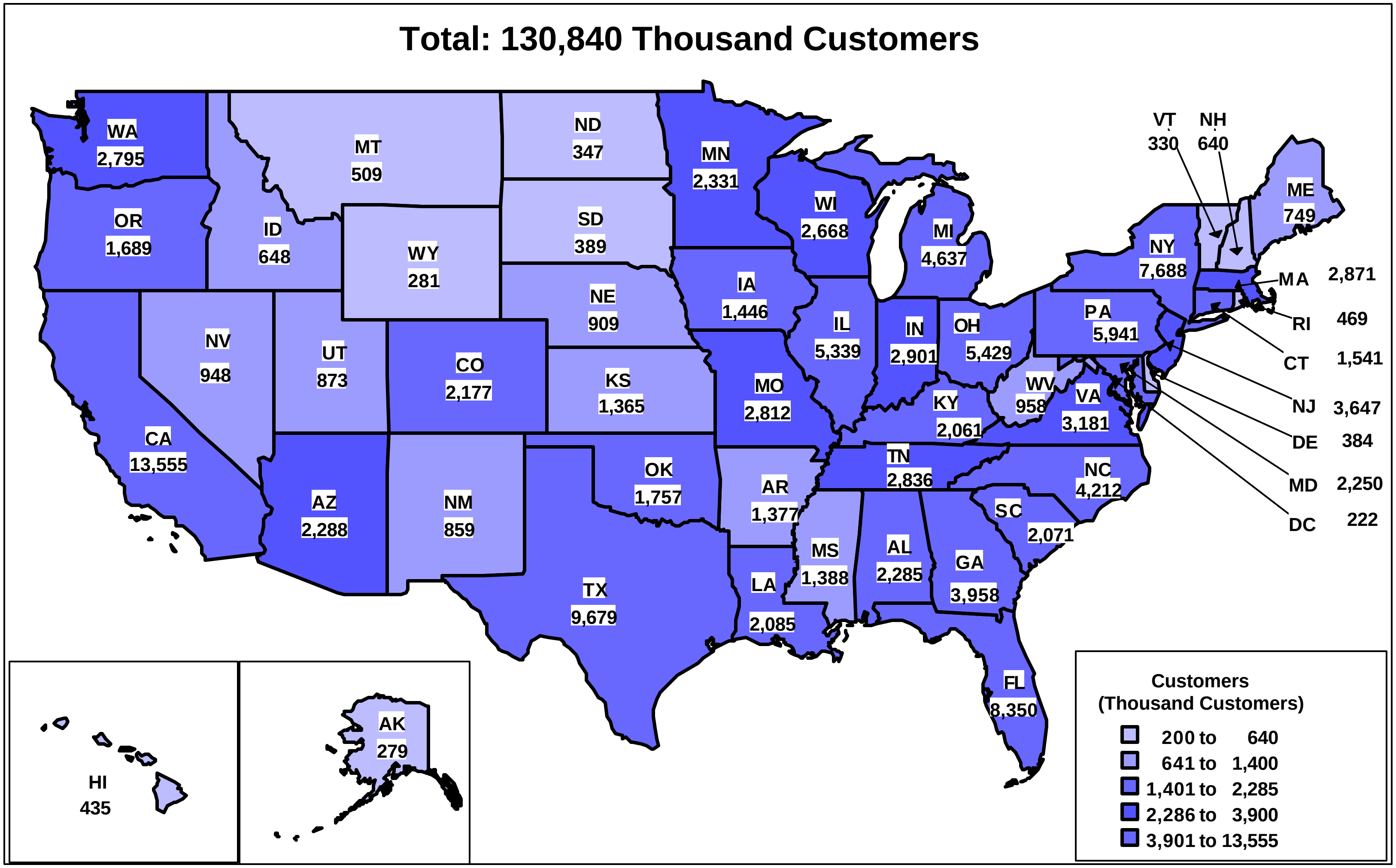
Period	Residential	Commercial	Industrial	Others[1]	All Sectors
			Total Electric Industry		
1990	97,094,514	12,081,942	525,486	858,800	110,560,742
1991	98,295,518	12,178,694	518,272	887,499	111,879,983
1992	99,512,728	12,367,205	547,990	857,614	113,285,537
1993	100,860,071	12,526,377	553,231	795,298	114,734,977
1994	102,320,846	12,733,153	583,935	850,770	116,488,704
1995	103,917,312	12,949,365	580,626	882,422	118,329,725
1996	105,343,005	13,181,065	586,198	893,884	120,004,152
1997	107,065,589	13,542,374	563,223	951,863	122,123,049
1998	109,048,343	13,887,066	539,903	932,838	124,408,150
1999	110,383,238	14,073,764	552,690	935,311	125,945,003
2000	111,717,711	14,349,067	526,554	974,185	127,567,517
2001	114,317,707	14,939,895	574,361	1,008,212	130,840,175
			Full-Service Providers		
1990	97,094,514	12,081,942	525,486	858,800	110,560,742
1991	98,295,518	12,178,694	518,272	887,499	111,879,983
1992	99,512,728	12,367,205	547,990	857,614	113,285,537
1993	100,860,071	12,526,377	553,231	795,298	114,734,977
1994	102,320,846	12,733,153	583,935	850,770	116,488,704
1995	103,917,312	12,949,365	580,626	882,422	118,329,725
1996	105,341,408	13,180,632	586,169	893,884	120,002,093
1997	107,033,338	13,540,374	562,972	951,863	122,088,547
1998	108,736,845	13,832,662	538,167	932,838	124,040,512
1999	109,817,057	13,963,937	527,329	934,260	125,242,583
2000	110,505,820	14,058,271	512,551	953,756	126,030,398
2001	112,533,187	14,535,461	558,381	1,001,641	128,628,670
			Energy-Only Providers		
1990	--	--	--	--	--
1991	--	--	--	--	--
1992	--	--	--	--	--
1993	--	--	--	--	--
1994	--	--	--	--	--
1995	--	--	--	--	--
1996	1,597	433	29	0	2,059
1997	32,251	2,000	251	0	34,502
1998	311,498	54,404	1,736	0	367,638
1999	566,181	109,827	25,361	1,051	702,420
2000	1,211,891	290,796	14,003	20,429	1,537,119
2001	1,784,520	404,434	15,980	6,571	2,211,505

[1] Miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales included.

Notes: ·See Glossary 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, 2001



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

Table 7.2. Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1990 through 2001
(Megawatthours)

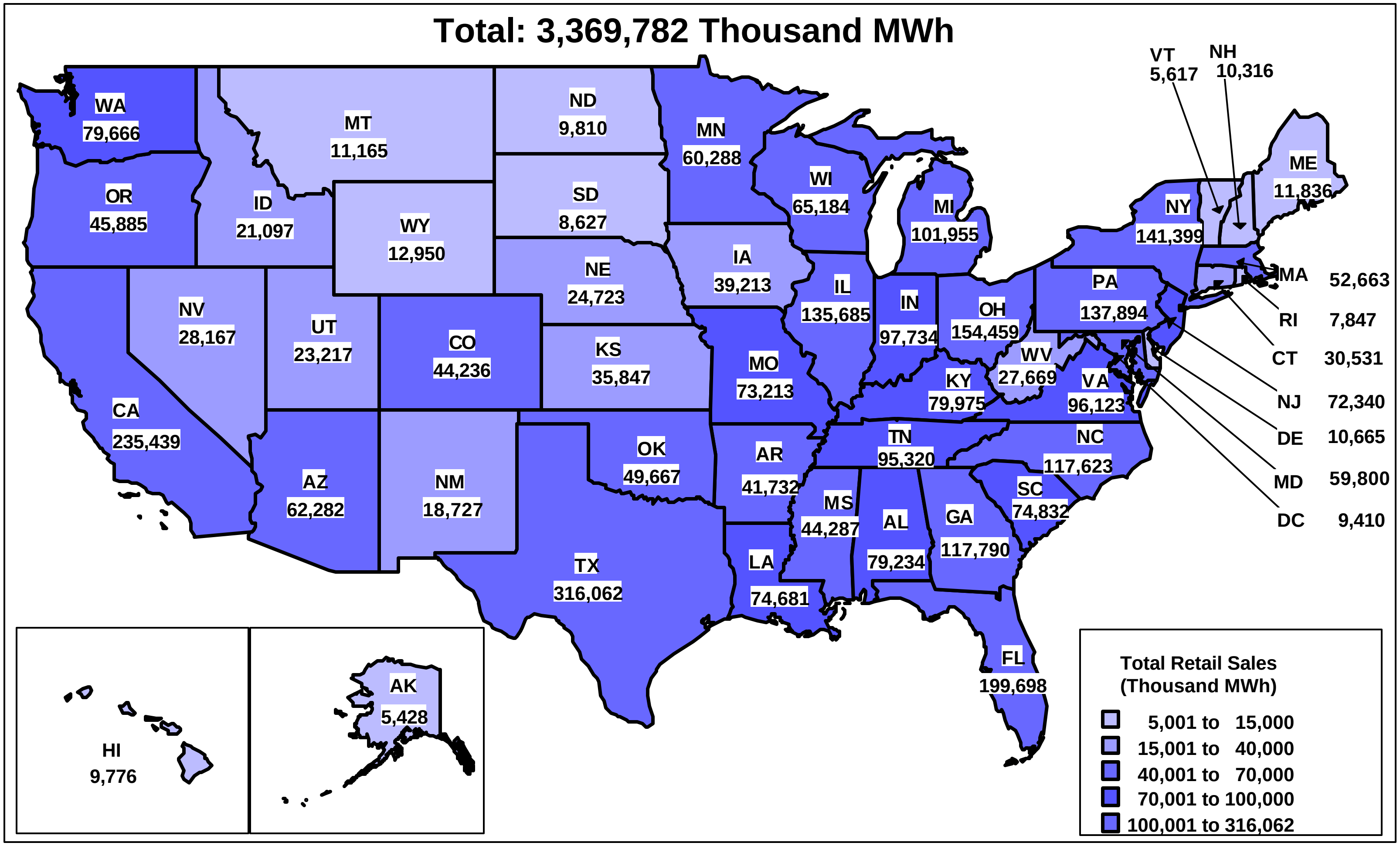
Period	Residential	Commercial	Industrial	Others[1]	All Sectors
Total Electric Industry					
1990	924,018,699	751,026,562	945,521,695	91,987,709	2,712,554,665
1991	955,417,350	765,663,613	946,583,391	94,338,686	2,762,003,040
1992	935,938,788	761,270,543	972,713,990	93,442,150	2,763,365,449
1993	994,780,818	794,573,370	977,164,250	94,943,902	2,861,462,340
1994	1,008,481,682	820,269,462	1,007,981,245	97,830,475	2,934,562,864
1995	1,042,501,471	862,684,775	1,012,693,350	95,406,993	3,013,286,589
1996	1,082,511,751	887,445,174	1,033,631,379	97,538,719	3,101,127,023
1997	1,075,880,098	928,632,774	1,038,196,892	102,900,664	3,145,610,428
1998	1,130,109,120	979,400,928	1,051,203,115	103,517,589	3,264,230,752
1999	1,144,923,069	1,001,995,720	1,058,216,608	106,951,684	3,312,087,081
2000	1,192,446,491	1,055,232,090	1,064,239,393	109,496,292	3,421,414,266
2001	1,202,646,738	1,089,153,700	964,224,282	113,756,089	3,369,781,529
Full-Service Providers					
1990	924,018,699	751,026,562	945,521,695	91,987,709	2,712,554,665
1991	955,417,350	765,663,613	946,583,391	94,338,686	2,762,003,040
1992	935,938,788	761,270,543	972,713,990	93,442,150	2,763,365,449
1993	994,780,818	794,573,370	977,164,250	94,943,902	2,861,462,340
1994	1,008,481,682	820,269,462	1,007,981,245	97,830,475	2,934,562,864
1995	1,042,501,471	862,684,775	1,012,693,350	95,406,993	3,013,286,589
1996	1,082,490,541	887,424,657	1,030,356,028	97,538,719	3,097,809,945
1997	1,075,766,590	928,440,265	1,032,653,445	102,900,664	3,139,760,964
1998	1,127,734,988	968,528,009	1,040,037,873	103,517,589	3,239,818,459
1999	1,140,761,016	970,600,943	1,017,783,037	106,754,043	3,235,899,039
2000	1,183,137,429	1,000,865,367	1,017,722,945	107,824,323	3,309,550,064
2001	1,168,538,228	1,020,839,106	930,011,833	105,436,926	3,224,826,813
Energy-Only Providers					
1990	--	--	--	--	--
1991	--	--	--	--	--
1992	--	--	--	--	--
1993	--	--	--	--	--
1994	--	--	--	--	--
1995	--	--	--	--	--
1996	21,210	20,517	3,275,351	0	3,317,078
1997	113,508	192,509	5,543,447	0	5,849,464
1998	2,374,132	10,872,919	11,165,242	0	24,412,293
1999	4,162,053	31,394,777	40,433,571	197,641	76,188,042
2000	9,309,062	54,366,723	46,516,448	1,671,969	111,864,202
2001	34,108,510	68,314,594	34,212,449	8,319,163	144,954,716

[1] Miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales included.

Notes: ·See Glossary 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.·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. 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 for the calendar year 2001 of approximately 58.9 million megawatthours and associated revenue, related to the CDWR's intervention in the crisis, are identified as "Energy Only Providers."

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, 2001 (Thousand MWh)



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, 1990 through 2001
(Million Dollars)[1]

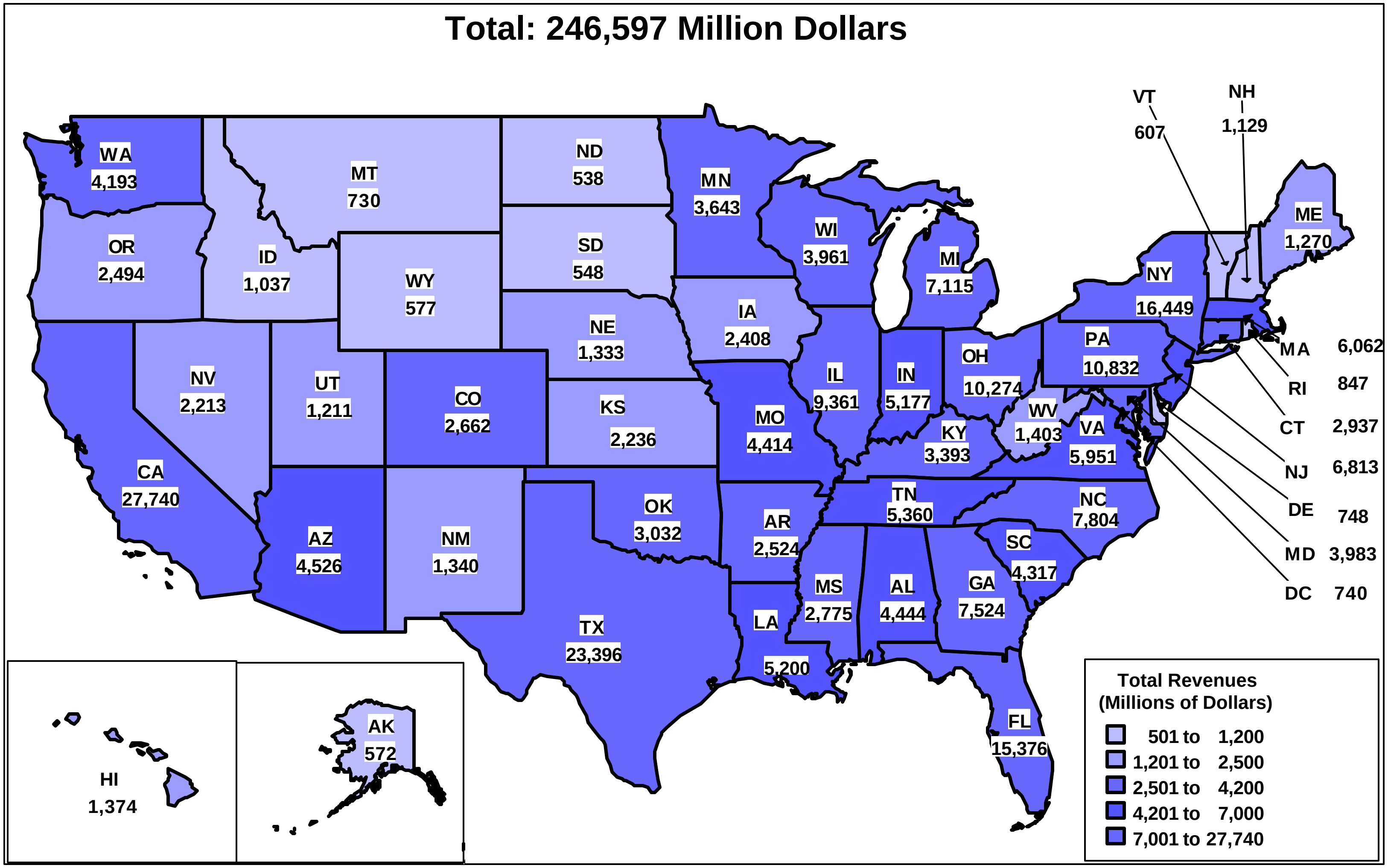
Period	Residential	Commercial	Industrial	Others[2]	All Sectors
Total Electric Industry					
1990	72,378	55,117	44,857	5,891	178,243
1991	76,828	57,655	45,737	6,138	186,359
1992	76,848	58,343	46,993	6,296	188,480
1993	82,814	61,521	47,357	6,528	198,220
1994	84,552	63,396	48,069	6,689	202,706
1995	87,610	66,365	47,175	6,567	207,717
1996	90,503	67,829	47,536	6,741	212,609
1997	90,704	70,497	47,023	7,110	215,334
1998	93,360	72,575	47,050	6,863	219,848
1999	93,483	72,771	46,846	6,796	219,896
2000	98,209	78,405	49,369	7,179	233,163
2001	103,671	86,354	48,573	7,999	246,597
Full-Service Providers					
1990	72,378	55,117	44,857	5,891	178,243
1991	76,828	57,655	45,737	6,138	186,359
1992	76,848	58,343	46,993	6,296	188,480
1993	82,814	61,521	47,357	6,528	198,220
1994	84,552	63,396	48,069	6,689	202,706
1995	87,610	66,365	47,175	6,567	207,717
1996	90,501	67,827	47,385	6,741	212,455
1997	90,694	70,482	46,772	7,110	215,059
1998	93,164	71,769	46,550	6,863	218,346
1999	93,142	70,492	45,056	6,783	215,473
2000	97,086	73,704	46,465	6,988	224,243
2001	100,004	79,901	46,040	7,242	233,187
Energy-Only Providers					
1990	--	--	--	--	--
1991	--	--	--	--	--
1992	--	--	--	--	--
1993	--	--	--	--	--
1994	--	--	--	--	--
1995	--	--	--	--	--
1996[3]	2	2	151	0	154
1997[3]	10	15	251	0	275
1998[3]	196	806	500	0	1,502
1999[3]	340	2,279	1,791	13	4,423
2000	530	3,175	2,374	75	6,153
2001	2,607	4,978	1,984	640	10,209
Delivery-Only Service					
1990	--	--	--	--	--
1991	--	--	--	--	--
1992	--	--	--	--	--
1993	--	--	--	--	--
1994	--	--	--	--	--
1995	--	--	--	--	--
1996	--	--	--	--	--
1997	--	--	--	--	--
1998	--	--	--	--	--
1999	--	--	--	--	--
2000	593	1,527	531	116	2,767
2001	1,060	1,475	549	117	3,201

[1] All "dollars" are nominal dollars.
[2] Miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales included.
[3] Revenue estimated based on retail sales reported on the Form EIA-861.

Notes: ·See Glossary 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.·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. 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 for the calendar year 2001 of approximately 58.9 million megawatthours and associated revenue, related to the CDWR's intervention in the crisis, are identified as "Energy Only Providers."·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, 2001 (Millions of Dollars)



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

Table 7.4. Average Revenue per Kilowatthour from Retail Sales to Ultimate Customers by Sector, by Provider, 1990 through 2001
(Cents)

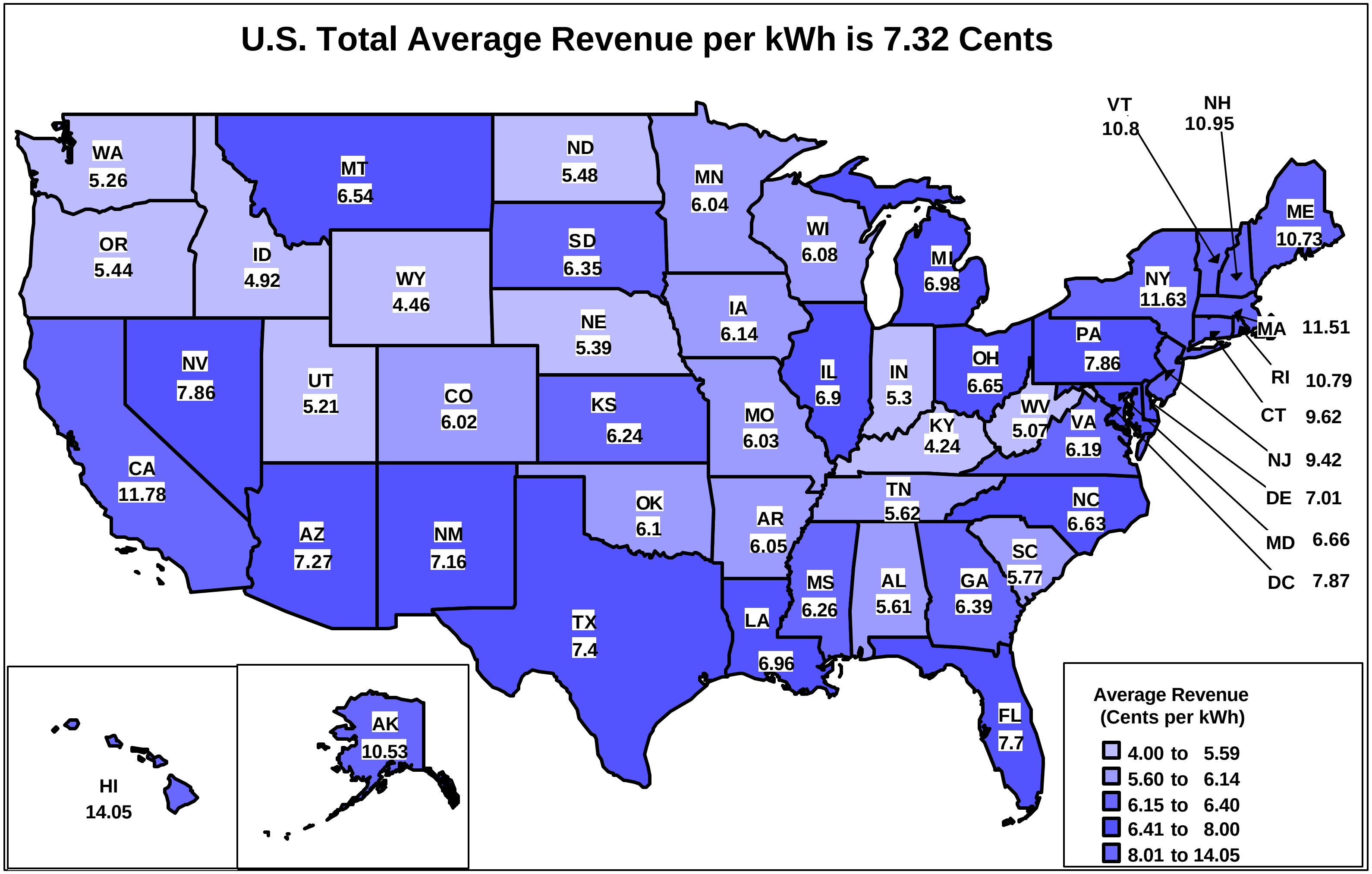
Period	Residential	Commercial	Industrial	Others[1]	All Sectors
Total Electric Industry					
1990	7.83	7.34	4.74	6.40	6.57
1991	8.04	7.53	4.83	6.51	6.75
1992	8.21	7.66	4.83	6.74	6.82
1993	8.32	7.74	4.85	6.88	6.93
1994	8.38	7.73	4.77	6.84	6.91
1995	8.40	7.69	4.66	6.88	6.89
1996	8.36	7.64	4.60	6.91	6.86
1997	8.43	7.59	4.53	6.91	6.85
1998	8.26	7.41	4.48	6.63	6.74
1999	8.16	7.26	4.43	6.35	6.64
2000	8.24	7.43	4.64	6.56	6.81
2001	8.62	7.93	5.04	7.03	7.32
Full-Service Providers					
1990	7.83	7.34	4.74	6.40	6.57
1991	8.04	7.53	4.83	6.51	6.75
1992	8.21	7.66	4.83	6.74	6.82
1993	8.32	7.74	4.85	6.88	6.93
1994	8.38	7.73	4.77	6.84	6.91
1995	8.40	7.69	4.66	6.88	6.89
1996	8.36	7.64	4.60	6.91	6.86
1997	8.43	7.59	4.53	6.91	6.85
1998	8.26	7.41	4.48	6.63	6.74
1999	8.16	7.26	4.43	6.35	6.66
2000	8.21	7.36	4.57	6.48	6.78
2001	8.56	7.83	4.95	6.87	7.23
Energy-Only Providers					
1990	--	--	--	--	--
1991	--	--	--	--	--
1992	--	--	--	--	--
1993	--	--	--	--	--
1994	--	--	--	--	--
1995	--	--	--	--	--
1996[2]	8.36	7.64	4.60	--	6.86
1997[2]	8.43	7.59	4.53	--	6.85
1998[2]	8.26	7.41	4.48	--	6.74
1999[2]	8.16	7.26	4.43	6.35	6.66
2000	12.07	8.65	6.24	11.42	7.97
2001	10.75	9.45	7.41	9.09	9.25

[1] Miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales included.
[2] Average revenue estimated based on retail sales reported on the Form EIA-861.

Notes: ·See Glossary 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.

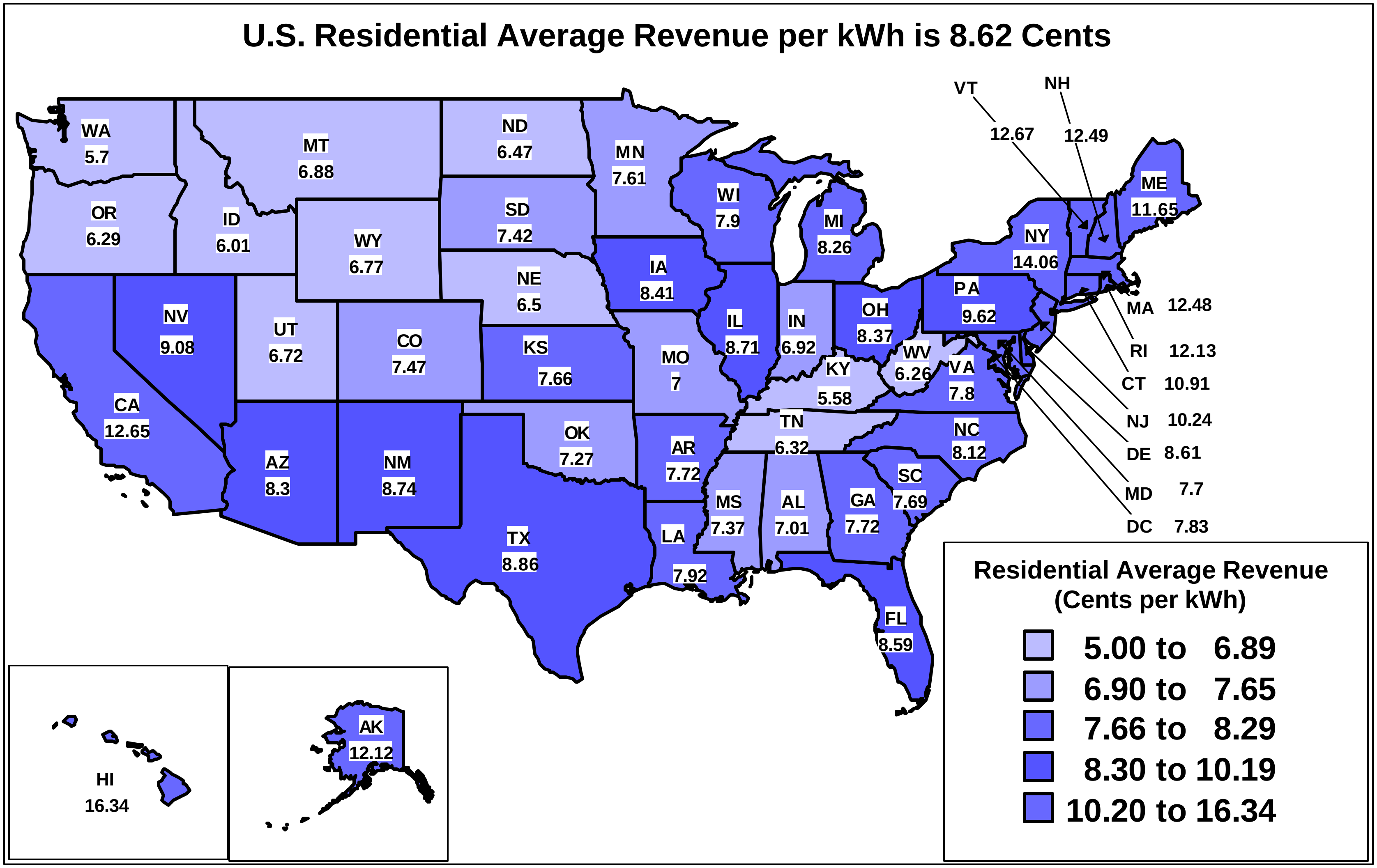
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.4 U.S. Electric Power Industry
Average Revenue per Kilowatthour by State, 2001
(Cents per kWh)



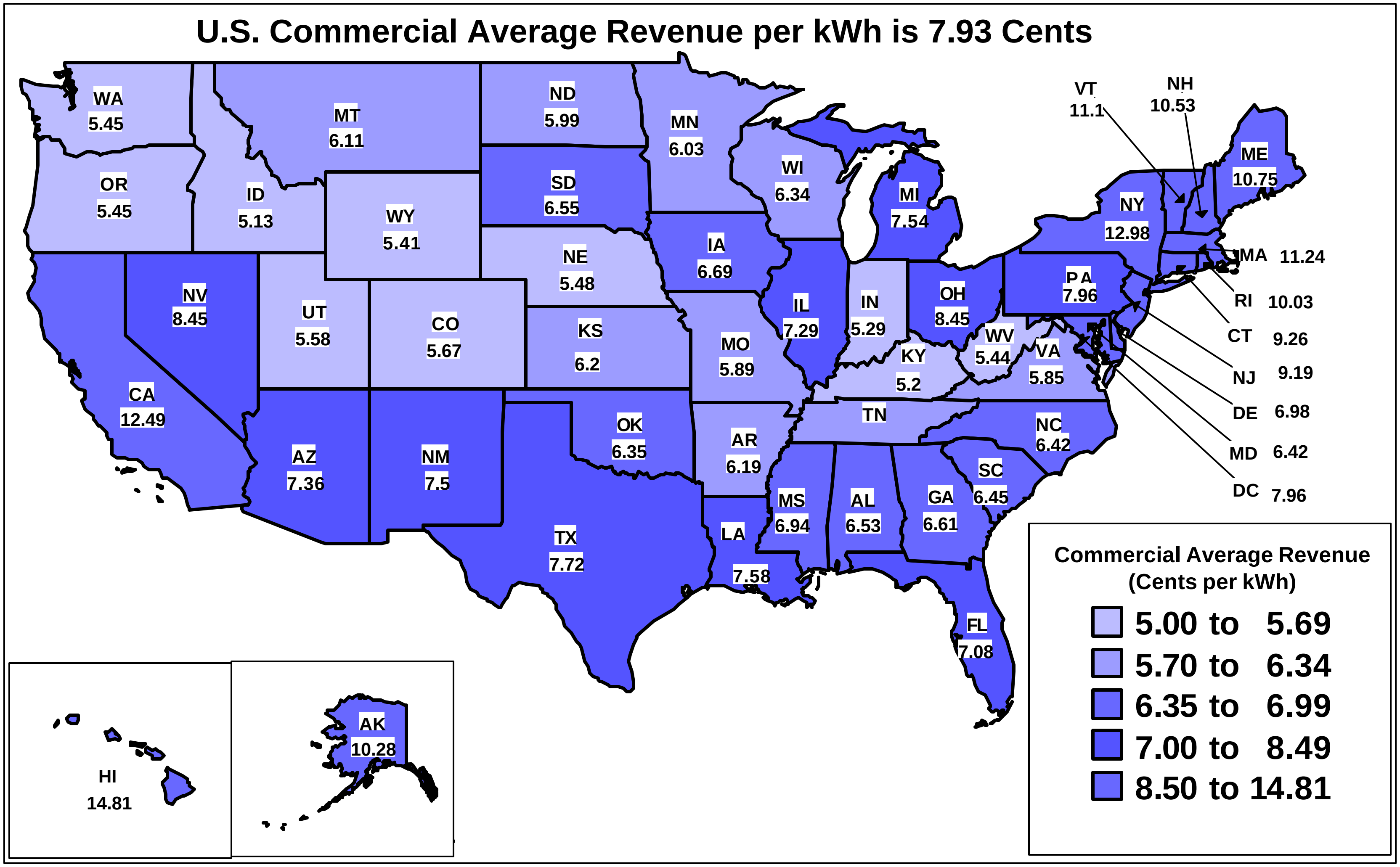
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.5 U.S. Electric Power Industry Residential Average Revenue per Kilowatthour by State, 2001 (Cents per kWh)



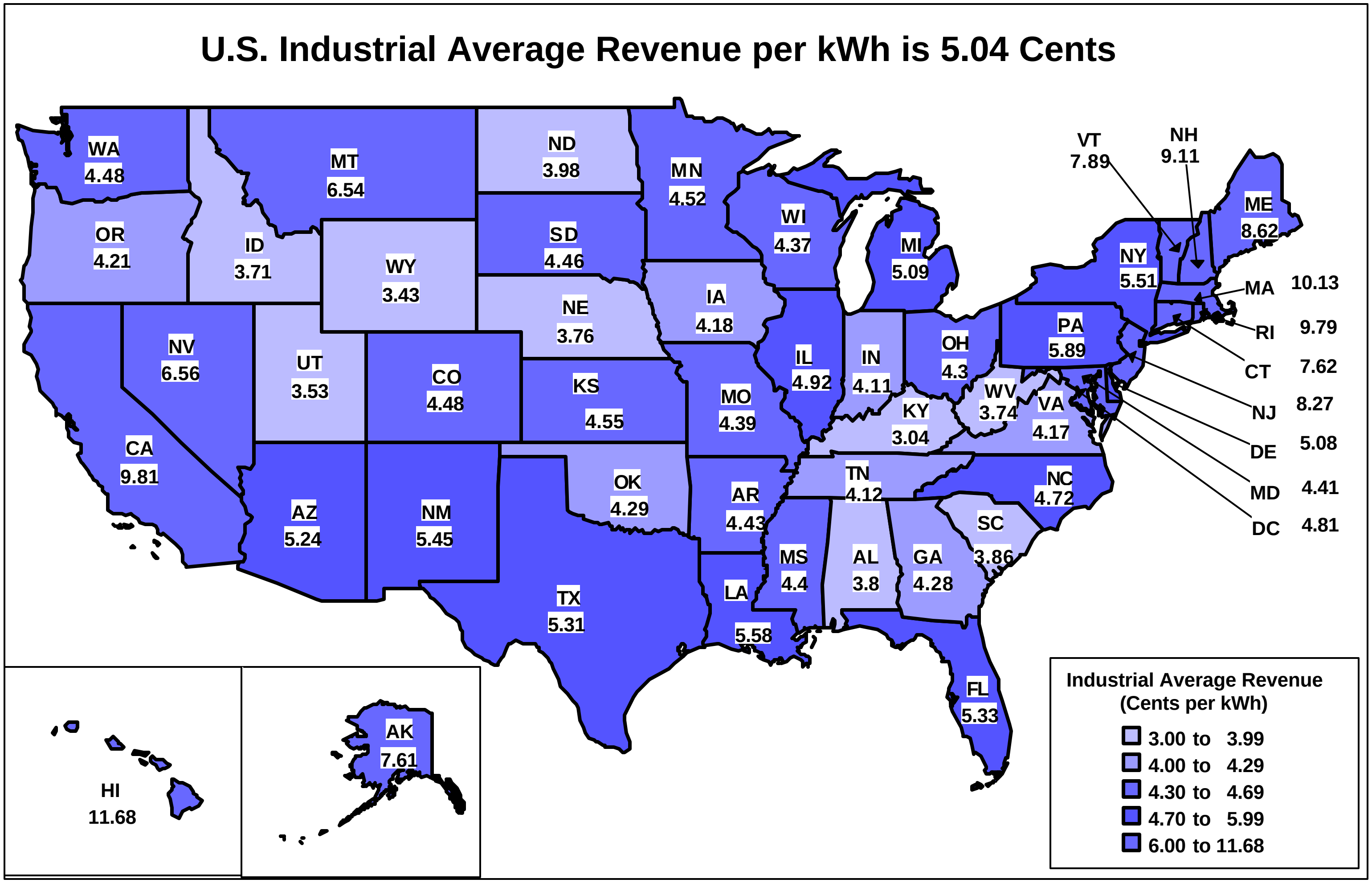
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.6 U.S. Electric Power Industry Commercial Average Revenue per Kilowatthour by State, 2001 (Cents per kWh)



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

Figure 7.7 U.S. Electric Power Industry Industrial Average Revenue per Kilowatthour by State, 2001 (Cents per kWh)



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, 1990 through 2001

(Million Dollars)[1]

Description	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Utility Operating Revenues	**267,525**	**235,336**	**214,160**	**218,175**	**215,083**	**207,459**	**199,967**	**196,282**	**193,638**	**185,493**	**182,451**	**173,000**
Electric Utility	244,219	214,707	197,578	201,970	195,898	188,901	183,655	179,307	176,354	169,488	166,804	157,279
Other Utility	23,306	20,630	16,583	16,205	19,185	18,558	16,312	16,974	17,283	16,005	15,647	15,721
Utility Operating Expenses	**235,198**	**210,324**	**182,258**	**186,498**	**182,796**	**173,920**	**165,321**	**164,207**	**161,908**	**153,682**	**150,362**	**142,471**
Electric Utility	213,733	191,329	167,266	171,689	165,443	156,938	150,599	148,663	146,118	139,009	135,948	127,901
Operation	159,929	132,662	108,461	110,759	104,337	97,207	91,881	93,108	91,328	87,272	85,934	81,086
Production	136,089	107,352	83,555	85,956	80,153	73,437	68,983	69,269	68,781	66,980	66,102	62,501
Cost of Fuel	29,490	32,555	29,826	31,252	31,861	30,706	29,122	30,108	31,214	30,254	31,312	32,635
Purchased Power	98,231	61,969	43,258	42,612	37,991	32,987	29,981	29,213	27,716	26,212	24,169	20,341
Other	8,368	12,828	10,470	12,092	10,301	9,744	9,880	9,948	9,851	10,513	10,620	9,526
Transmission	2,365	2,699	2,423	2,197	1,915	1,503	1,425	1,361	1,354	1,308	1,247	1,130
Distribution	3,217	3,115	2,956	2,804	2,700	2,604	2,561	2,581	2,595	2,499	2,530	2,444
Customer Accounts	4,434	4,246	4,195	4,021	3,767	3,848	3,613	3,546	3,418	3,347	3,203	3,247
Customer Service	1,856	1,839	1,889	1,955	1,197	1,920	1,922	1,956	1,852	1,531	1,452	1,181
Sales	282	403	492	514	501	435	348	232	203	199	203	212
Administrative and General	11,686	13,009	12,951	13,311	13,384	13,458	13,028	14,163	13,124	11,409	11,196	10,371
Maintenance	11,167	12,185	12,276	12,486	12,368	12,050	11,767	12,022	12,447	12,195	12,024	11,779
Depreciation	20,845	22,761	23,968	24,122	23,072	21,194	19,885	18,679	18,099	17,092	16,127	14,889
Taxes and Other	21,792	23,721	22,561	24,322	25,667	26,488	27,065	24,854	24,244	22,450	21,863	20,146
Other Utility	21,465	18,995	14,992	14,809	17,353	16,983	14,722	15,544	15,790	14,673	14,414	14,571
Net Utility Operating Income	**32,327**	**25,012**	**31,902**	**31,677**	**32,286**	**33,539**	**34,646**	**32,074**	**31,730**	**31,811**	**32,089**	**30,529**

[1] All "dollars" are nominal dollars.

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, 1990 through 2001

(Mills per Kilowatthour)

Plant Type	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Operation												
Nuclear	8.30	8.41	8.93	9.98	11.02	9.47	9.43	9.79	10.20	10.43	10.49	10.04
Fossil Steam	2.40	2.31	2.21	2.17	2.22	2.25	2.38	2.32	2.37	2.38	2.29	2.21
Hydroelectric[1]	5.79	4.74	4.17	3.85	3.29	3.87	3.69	4.53	3.82	4.33	3.88	3.35
Gas Turbine and Small Scale[2]	3.15	4.57	5.16	3.85	4.43	5.08	3.57	4.58	6.47	10.18	9.61	8.76
Maintenance												
Nuclear	5.01	4.93	5.13	5.79	6.90	5.68	5.21	5.20	5.73	5.93	5.50	5.68
Fossil Steam	2.61	2.45	2.38	2.41	2.43	2.49	2.65	2.82	2.96	2.95	2.98	2.97
Hydroelectric[1]	3.97	2.99	2.60	2.00	2.49	2.08	2.19	2.90	2.65	3.30	2.89	2.58
Gas Turbine and Small Scale[2]	3.33	3.50	4.80	3.43	3.43	4.98	4.28	5.39	7.52	12.15	12.93	12.23
Fuel												
Nuclear	4.67	4.95	5.17	5.39	5.42	5.50	5.75	5.87	5.88	6.12	6.71	7.18
Fossil Steam	18.13	17.69	15.62	15.94	16.80	16.51	16.07	16.67	17.65	17.49	17.91	18.55
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small Scale[2]	43.56	39.19	28.72	23.02	24.94	30.58	20.83	22.19	26.39	28.59	30.96	32.57
Total												
Nuclear	17.98	18.28	19.23	21.16	23.33	20.65	20.39	20.86	21.80	22.48	22.70	22.91
Fossil Steam	23.14	22.44	20.22	20.52	21.45	21.25	21.11	21.80	22.97	22.83	23.17	23.72
Hydroelectric[1]	9.76	7.73	6.77	5.86	5.78	5.95	5.89	7.43	6.47	7.63	6.76	5.93
Gas Turbine and Small Scale[2]	50.04	47.26	38.68	30.30	32.80	40.64	28.67	32.16	40.38	50.92	53.51	53.56

[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), 1990 through 2001

(Million Dollars)[1]

Description	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Operating Revenue - Electric	**38,028**	**31,843**	**26,767**	**26,155**	**25,397**	**24,207**	**23,473**	**23,267**	**22,522**	**21,686**	**21,083**	**20,470**
Operating Expenses - Electric	**32,811**	**26,244**	**21,274**	**20,880**	**20,425**	**19,084**	**18,959**	**18,649**	**18,162**	**17,191**	**16,887**	**16,461**
Operation Including Fuel	**25,941**	**19,575**	**15,386**	**15,120**	**14,917**	**13,768**	**13,653**	**13,578**	**13,242**	**12,527**	**12,155**	**11,948**
Production	21,783	15,742	11,923	11,608	11,481	11,080	10,385	10,445	10,254	9,712	9,465	9,525
Transmission	785	781	732	773	725	344	628	610	580	535	509	472
Distribution	605	574	516	603	538	497	426	430	408	389	363	329
Customer Accounts	600	507	415	390	390	365	323	317	315	299	289	273
Customer Service	263	211	160	127	133	103	102	104	94	83	74	60
Sales	73	66	49	51	46	18	20	22	17	18	18	18
Administrative and General	1,832	1,695	1,591	1,567	1,602	1,360	1,769	1,651	1,573	1,492	1,437	1,271
Maintenance	**1,905**	**1,815**	**1,686**	**1,631**	**1,609**	**1,638**	**1,575**	**1,584**	**1,565**	**1,565**	**1,446**	**1,456**
Depreciation and Amortization	**4,009**	**3,919**[R]	**3,505**[R]	**3,459**[R]	**3,239**[R]	**3,160**[R]	**2,934**	**2,721**[R]	**2,596**[R]	**2,417**[R]	**2,301**	**2,076**
Taxes and Tax Equivalents	**954**	**936**	**697**	**670**	**660**	**662**	**797**	**766**	**759**	**681**	**596**	**550**
Net Electric Operating Income	**5,217**	**5,598**	**5,493**	**5,275**	**4,972**	**5,123**	**4,514**	**4,618**	**4,360**	**4,496**	**4,196**	**4,010**

[1] All "dollars" are nominal dollars.

R = Revised.

Notes: ·Totals may not equal sum of components because of independent rounding.·The 1998-2001 data represent those utilities meeting a threshold of 150 million kilowatthours of customer sales or resales. The 1990-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of customer sales or resales.

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), 1990 through 2001

(Million Dollars)[1]

Description	2001[2]	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Operating Revenue - Electric	**10,417**	**9,904**	**9,354**	**8,790**	**8,586**	**8,582**	**8,435**	**7,996**	**7,523**	**7,247**	**7,120**	**6,979**
Operating Expenses - Electric	**9,820**	**9,355**	**8,737**	**8,245**	**8,033**	**8,123**	**7,979**	**7,567**	**7,063**	**6,844**	**6,860**	**6,741**
Operation Including Fuel	**8,864**	**8,424**	**7,874**	**7,437**	**7,117**	**7,359**	**7,173**	**6,858**	**6,425**	**6,245**	**6,119**	**6,030**
Production	7,863	7,486	7,015	6,661	6,240	6,578	6,422	6,185	5,761	5,617	5,524	5,479
Transmission	61	64	48	44	57	51	35	34	34	33	32	30
Distribution	311	280	261	230	304	234	204	190	189	176	164	145
Customer Accounts	164	155	143	130	139	141	125	119	117	109	102	99
Customer Service	26	22	22	21	16	18	18	17	17	16	16	14
Sales	15	16	14	9	13	12	10	10	9	12	12	11
Administrative and General	423	402	371	342	348	325	358	303	298	282	270	252
Maintenance	**304**	**286**	**272**	**263**	**338**	**244**	**250**	**234**	**207**	**193**	**186**	**192**
Depreciation and Amortization	**405**	**394**[R]	**369**[R]	**330**[R]	**354**[R]	**322**[R]	**313**	**274**[R]	**257**[R]	**251**[R]	**247**	**231**
Taxes and Tax Equivalents	**247**	**251**	**223**	**215**	**225**	**206**	**244**	**201**	**175**	**155**	**138**	**133**
Net Electric Operating Income	**597**	**549**	**617**	**545**	**552**	**459**	**457**	**429**	**460**	**404**	**260**	**238**

[1] All "dollars" are nominal dollars.

[2] For 2001, California Department of Water Resources - Electric Energy Fund data were excluded from these statistics. In response to the looming energy shortfall in California, 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 revenues collected were $5,501,000,000 with purchase power costs of $12,055,000,000. The California Public Utility Commission was required by statute to establish the procedure for retail revenue recovery mechanisms for these purchase power costs in the future.

R = Revised.

Notes: ·Totals may not equal sum of components because of independent rounding.·The 1998-2001 data represent those utilities meeting a threshold of 150 million kilowatthours of customer sales or resales. The 1990-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of customer sales or resales.

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, 1990 through 2001
(Million Dollars)[1]

Description	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Operating Revenue - Electric	**12,136**	**10,685**	**10,186**	**9,780**	**8,833**	**9,082**	**8,743**	**8,552**	**8,141**	**7,872**	**8,194**	**8,197**
Operating Expenses - Electric	**9,785**	**8,139**	**7,775**	**7,099**	**5,999**	**6,390**	**6,162**	**6,303**	**6,056**	**5,883**	**5,288**	**5,428**
Operation Including Fuel	**7,033**	**5,873**	**5,412**	**5,184**	**4,073**	**4,514**	**4,615**	**4,877**	**4,827**	**4,595**	**4,115**	**3,989**
Production	5,912	5,497	4,890	4,735	3,686	4,109	4,219	4,464	4,272	4,144	3,650	3,564
Transmission	334	332	349	323	327	328	290	304	319	272	260	298
Distribution	1	2	2	2	1	1	2	2	2	2	3	2
Customer Accounts	16	6	1	1	1	3	2	4	4	3	4	4
Customer Service	60	48	50	51	42	46	29	28	27	26	23	22
Sales	6	10	28	14	13	7	41	9	6	5	4	4
Administrative and General	705	467	528	535	444	451	431	442	578	537	529	424
Maintenance	**521**	**488**	**436**	**476**	**441**	**432**	**398**	**377**	**381**	**394**	**358**	**329**
Depreciation and Amortization	**1,915**	**1,471**	**1,623**	**1,175**	**1,214**	**1,187**	**896**	**746**	**611**	**653**	**572**	**826**
Taxes and Tax Equivalents	**315**	**308**	**304**	**264**	**272**	**256**	**252**	**56**	**237**	**241**	**243**	**283**
Net Electric Operating Income	**2,352**	**2,546**	**2,411**	**2,681**	**2,834**	**2,692**	**2,581**	**2,249**	**2,085**	**1,989**	**2,906**	**2,769**

[1] All "dollars" are nominal dollars.

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 Major U.S. Cooperative Borrower Owned Electric Utilities, 1990 through 2001
(Million Dollars)[1]

Description	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Operating Revenue - Electric	**26,402**	**25,629**	**23,824**	**23,988**	**23,321**	**24,424**	**24,609**	**23,777**	**24,873**	**23,325**	**22,784**	**22,226**
Operation and Maintenance Expenses	**23,714**	**22,982**	**21,283**	**21,223**	**20,715**	**23,149**	**21,741**	**20,993**	**21,675**	**20,353**	**19,887**	**19,169**
Operation Including Fuel	**21,661**	**20,942**	**19,336**	**19,280**	**18,405**	**20,748**	**19,334**	**18,650**	**19,292**	**18,038**	**17,655**	**17,037**
Production	17,618	17,080	15,706	15,683	15,105	17,422	15,907	15,471	16,101	15,059	14,836	14,347
Transmission	551	525	466	452	339	372	366	322	336	324	313	318
Distribution	1,601	1,530	1,451	1,440	1,134	1,133	1,127	1,053	1,044	980	917	874
Customer Accounts	515	487	455	446	382	375	383	374	386	369	349	334
Customer Service	135	133	132	132	118	118	112	105	101	95	89	83
Sales	88	82	81	77	61	72	72	61	57	52	47	42
Administrative and General	1,154	1,104	1,045	1,050	1,266	1,257	1,367	1,265	1,265	1,160	1,104	1,039
Depreciation and Amortization	**1,889**	**1,820**	**1,747**	**1,732**	**1,727**	**1,787**	**1,778**	**1,742**	**1,768**	**1,709**	**1,639**	**1,617**
Taxes and Tax Equivalents	**164**	**220**	**200**	**211**	**583**	**614**	**628**	**601**	**616**	**605**	**593**	**515**
Net Electric Operating Income	**2,688**	**2,647**	**2,541**	**2,764**	**2,606**	**2,872**	**2,868**	**2,784**	**3,197**	**2,973**	**2,897**	**3,057**

[1] All "dollars" are nominal dollars.

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, 1990 through 2001
(Megawatts)

Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Total Actual Peak Load Reduction[1]	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**	**23,069**	**17,204**	**15,619**	**13,704**
Energy Efficiency	13,027	12,873	13,452	13,591	13,326	14,243	13,212	11,662	10,368	7,890	NA	NA
Load Management	11,928	10,027	13,003	13,640	11,958	15,650	16,347	13,340	12,701	9,314	NA	NA

[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).

NA = Not available.

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, 1990 through 2001

Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
	Annual Effects – Energy Efficiency											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	13,027	12,873	13,452	13,591	13,327	14,243	13,212	11,662	10,368	7,890	NA	NA
Energy Savings (Thousand MWh)	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119	31,779	NA	NA
	Annual Effects – Load Management											
Large Utilities[1]												
Actual Peak Load Reduction (MW)	11,928	10,027	13,003	13,640	11,958	15,650	16,349	13,339	12,701	9,314	NA	NA
Potential Peak Load Reductions (MW)[3]	27,730	28,496	30,118	27,840	27,911	34,101	33,817	31,255	29,140	24,552	NA	NA
Energy Savings (Thousand MWh)	1,816	875	872	392	953	1,989	2,093	2,763	4,175	4,114	NA	NA

[1] Refers to electric utilities with sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2001 and 120 million kilowatthours in 1990-1997.
[2] Represents the actual reduction in annual peak load achieved by customers, at the time of annual peak load.
[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.

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, 1990 through 2001

Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
	Incremental Effects – Energy Efficiency											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	999	720	695	796	1,065	1,381	1,561	1,751	1,839	1,501	NA	NA
Energy Savings (Thousand MWh)	4,402	3,284	3,027	3,324	4,661	6,361	7,901	8,054	8,601	5,338	NA	NA
Small Utilities[3]												
Actual Peak Load Reduction (MW)[2]	20	25	22	12	12	2	7	9	9	17	NA	NA
Energy Savings (Thousand MWh)	8	8	8	37	10	7	16	11	12	12	NA	NA
	Incremental Effects – Load Management											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	1,297	919	1,568	1,821	1,261	5,027	3,039	1,418	2,809	2,437	NA	NA
Potential Peak Load Reductions (MW)[4]	2,448	2,439	6,457	2,832	2,475	2,309	4,930	5,153	5,298	6,077	NA	NA
Energy Savings (Thousand MWh)	905	63	67	37	171	482	321	178	508	447	NA	NA
Small Utilities[3]												
Actual Peak Load Reduction (MW)[2]	45	137	54	124	130	50	29	56	110	315	NA	NA
Potential Peak Load Reductions (MW)[4]	177	190	84	160	183	90	41	81	291	657	NA	NA
Energy Savings (Thousand MWh)	4	9	2	7	19	6	3	8	11	37	NA	NA

[1] Refers to electric utilities with sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2001 and 120 million kilowatthours in 1990-1997.
[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 sales to ultimate customers or sales for resale less than 150 million kilowatthours in 1998-2001 and 120 million kilowatthours in 1990-1997.
[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.

NA = Not available.

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, 1990 through 2001

Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
						Actual Peak Load Reductions[1] (MW)						
Large Utilities[2]												
Residential	9,619	9,446	9,976	9,327	10,799	11,471	10,930	9,638	8,851	7,606	NA	NA
Commercial	8,210	6,987	7,777	9,482	8,174	8,678	8,057	6,927	7,541	4,598	NA	NA
Industrial	6,553	6,141	6,360	7,927	5,812	9,083	10,033	7,977	6,270	4,467	NA	NA
Other	573	327	2,342	495	498	661	545	460	407	532	NA	NA
Total	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**	**23,069**	**17,204**	**15,619**	**13,704**
						Potential Peak Load Reductions[3] (MW)						
Large Utilities[2]												
Residential	12,274	12,970	12,812	13,022	16,662	14,697	14,047	13,851	12,868	11,058	NA	NA
Commercial	10,469	9,114	8,868	12,210	12,896	12,452	11,495	9,915	11,821	7,002	NA	NA
Industrial	17,344	18,775	17,237	15,512	11,035	20,275	20,715	18,271	13,957	13,367	NA	NA
Other	670	510	4,653	686	644	921	772	881	862	1,014	NA	NA
Total	**40,757**	**41,369**	**43,570**	**41,430**	**41,237**	**48,344**	**47,029**	**42,917**	**39,508**	**32,442**	**NA**	**NA**
						Energy Savings (Thousand MWh)						
Large Utilities[2]												
Residential	16,027	16,287	16,263	16,564	17,830	20,585	20,253	21,028	19,241	15,322	NA	NA
Commercial	24,217	25,660	23,375	25,125	27,898	29,186	26,187	21,773	16,567	12,301	NA	NA
Industrial	11,313	9,160	8,156	3,347	8,684	10,493	9,620	8,568	8,644	7,192	NA	NA
Other	3,206	2,593	2,770	831	1,694	1,578	1,360	1,114	842	748	NA	NA
Total	**54,762**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**	**45,294**	**35,563**	**24,848**	**20,458**

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 1998-2001 and 120 million kilowatthours in 1990-1997.
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.

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, 1990 through 2001

Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
						Actual Peak Load Reductions[1] (MW)						
Large Utilities[2]												
Residential	790	572	605	599	743	792	860	1,083	1,147	1,112	NA	NA
Commercial	742	515	684	1176	699	935	1176	1,244	1,427	1,251	NA	NA
Industrial	640	502	929	799	836	1,870	2,426	785	2,014	1,451	NA	NA
Other	124	50	45	43	48	93	139	57	61	108	NA	NA
Total	**2,296**	**1,640**	**2,263**	**2,617**	**2,326**	**3,690**	**4,601**	**3,169**	**4,648**	**3,922**	**NA**	**NA**
Small Utilities[3]												
Residential	32	37	27	35	40	30	20	27	76	139	NA	NA
Commercial	15	37	22	34	21	9	10	7	35	32	NA	NA
Industrial	16	62	7	56	61	8	4	24	47	113	NA	NA
Other	2	26	19	10	20	5	2	6	28	48	NA	NA
Total	**65**	**162**	**76**	**136**	**142**	**52**	**36**	**65**	**185**	**332**	**NA**	**NA**
U.S. Total	**2,361**	**1,802**	**2,339**	**2,753**	**2,468**	**3,742**	**4,637**	**3,234**	**4,833**	**4,254**	**NA**	**NA**
						Potential Peak Load Reductions[4] (MW)						
Large Utilities[2]												
Residential	900	699	753	751	960	950	1,231	1,467	NA	NA	NA	NA
Commercial	1,115	565	718	1,863	853	1,512	1,697	2,115	NA	NA	NA	NA
Industrial	1,277	1,815	5,612	1,438	1,669	3,800	3,368	1,997	NA	NA	NA	NA
Other	155	79	68	76	58	146	195	326	NA	NA	NA	NA
Total	**3,447**	**3,159**	**7,151**	**3,628**	**3,540**	**6,408**	**6,491**	**5,905**	**7,157**	**7,578**	**NA**	**NA**
Small Utilities[3]												
Residential	158	55	41	49	59	46	27	38	NA	NA	NA	NA
Commercial	19	51	25	41	35	17	13	12	NA	NA	NA	NA
Industrial	18	64	9	70	72	16	6	31	NA	NA	NA	NA
Other	2	44	31	12	30	13	2	8	NA	NA	NA	NA
Total	**197**	**215**	**106**	**172**	**196**	**92**	**48**	**89**	**300**	**674**	**NA**	**NA**
U.S. Total	**3,644**	**3,374**	**7,257**	**3,800**	**3,736**	**6,500**	**6,539**	**5,994**	**7,457**	**8,252**	**NA**	**NA**
						Energy Savings (Thousand MWh)						
Large Utilities[2]												
Residential	1,365	856	990	909	1,055	1,179	1,630	2,194	2,780	2,165	NA	NA
Commercial	1,867	1,780	1,502	1,703	2,382	3,537	4,594	4,449	4,557	3,333	NA	NA
Industrial	1,698	547	475	645	1,059	1,787	1,678	1,325	1,518	1,014	NA	NA
Other	376	164	127	104	336	341	320	262	125	151	NA	NA
Total	**5,307**	**3,347**	**3,094**	**3,361**	**4,832**	**6,844**	**8,222**	**8,230**	**8,980**	**6,664**	**NA**	**NA**
Small Utilities[3]												
Residential	5	9	4	8	10	7	9	13	13	14	NA	NA
Commercial	3	4	3	6	3	3	5	3	4	5	NA	NA
Industrial	2	1	1	3	8	2	5	1	3	26	NA	NA
Other	1	3	1	1	7	1	2	1	2	3	NA	NA
Total	**12**	**17**	**9**	**18**	**28**	**13**	**21**	**18**	**22**	**48**	**NA**	**NA**
U.S. Total	**5,318**	**3,364**	**3,103**	**3,379**	**4,860**	**6,857**	**8,243**	**8,248**	**9,002**	**6,712**	**NA**	**NA**

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 1998-2001 and 120 million kilowatthours in 1990-1997.
3 Refers to electric utilities with sales to ultimate customers or sales for resale less than 150 million kilowatthours in 1998-2001 and 120 million kilowatthours in 1990-1997.
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.

NA = Not available.

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, 1990 through 2001
(Megawatts)

Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Total Energy Savings[1]	**54,762**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**	**45,294**	**35,563**	**24,848**	**20,458**
Energy Efficiency	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119	31,779	NA	NA
Load Management	1,816	875	872	392	953	1,989	2,093	2,763	4,175	4,114	NA	NA

[1] Refers to electric utilities with sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2001 and 120 million kilowatthours in 1990-1997.

NA = Not available.

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, 1990 through 2001
(Thousand Dollars)

Item	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
Direct Cost[1]	**1,463,423**	**1,384,232**	**1,250,689**	**1,233,018**	**1,347,245**	**1,623,588**	**2,004,942**	**2,254,059**	**2,289,267**	**NA**	**NA**	**NA**
Energy Efficiency	1,101,517	938,666	820,108	766,384	892,468	1,051,922	1,408,542	1,592,125	1,607,952	NA	NA	NA
Load Management	361,906	445,566	430,581	466,634	454,777	571,666	596,400	661,934	681,315	NA	NA	NA
Indirect Cost[2]	**176,001**	**180,669**	**172,955**	**187,902**	**288,775**	**278,609**	**416,342**	**461,598**	**454,266**	**NA**	**NA**	**NA**
Total DSM Cost[3]	**1,639,424**	**1,564,901**	**1,423,644**	**1,420,920**	**1,636,020**	**1,902,197**	**2,421,284**	**2,715,657**	**2,743,533**	**2,348,094**	**1,803,773**	**1,177,457**

[1] Reflects electric utility cost 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 flows out to support demand-side management programs.

NA = Not available.

Note: 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

The Energy Information Administration (EIA) has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. Appendix B provides detail on these changes and describes the reasoning behind the changes and their effects on EIA forms and publications. 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.

Quality statistics begin with the collection of the correct data. To assure this, the CNEAF office performs routine reviews of the data collected and the forms on which it is collected. Additionally, to assure that the data is collected from the correct parties, CNEAF routinely reviews the frames for each data collection.

Automatic, computerized verification of keyed input, review by subject matter specialists, and follow-up with non-respondents also assure quality statistics. To ensure the quality standards established by the EIA, formulas that use the past history of data values in the database have been designed and implemented to check data input for errors automatically. Data values that fall outside the ranges prescribed in the formulas are verified by telephoning respondents to resolve any discrepancies. Also survey non-respondents are identified and contacted.

Reliability of Data

Annual survey data have nonsampling errors. Nonsampling errors can be attributed to many sources: (1) inability to obtain complete information about all cases in the sample (i.e., nonresponse); (2) response errors; (3) definitional difficulties; (4) differences in the interpretation of questions; (5) mistakes in recording or coding the data obtained; 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

The CNEAF office has adopted the following policy with respect to the revision and correction of recurrent data in energy publications:

1. Annual survey data collected by CNEAF are published either as preliminary or final when first appearing in a data report. Data initially released as preliminary will be so noted in the report. These data will be revised, if necessary, and declared final in the next publication of the data.

2. All monthly survey data collected by this office are published as preliminary. These data are typically revised only after the completion of the 12-month cycle of the data. No revisions are made to the published data before this unless major errors are discovered that may affect the national total.

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

4. After data are published as final, corrections will be made only in the event of a difference of one percent or greater at the national level. Corrections for differences that are less than the one percent or greater threshold are left to the discretion of the Office Director.

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** 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 and FERC Form 423. All data are final.
- **Chapter 5, Emissions** Based on data from the Form EIA-767 and the Form EIA-906. All data are final.
- **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 average revenue per kilowatthour 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, RUS Form 7, and RUS 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.

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. The EIA forms used are:

- Form EIA-411, "Coordinated Bulk Power Supply Program Report;"
- Form EIA-412, "Annual Electric Industry Financial 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."

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 (RUS) 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." 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/datamatrix.html.

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. These reports present various 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 forms are compiled from data furnished by electricity generators (members, associates, and nonmembers) within the council areas.

Rounding Rules for Data. Not applicable.

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

$$\left(\frac{x\ (t_2) - x\ (t_1)}{x\ (t_1)}\right) x\,100,$$

Percent Difference =

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

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

The Form EIA-412 is a restricted-universe census 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 MW or greater. Also beginning with the 2002 collection, the transmission data reported in Schedules 10 and 11 were collected from each generation and transmission cooperative owing transmission lines having a nominal voltage of 132 kV or greater. The 1999-1997 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 results in 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.

Instrument and Design History. The 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 processing of data reported on this survey is the responsibility of the Electric Power Division within the Office of Coal, Nuclear, Electric and Alternate Fuels. The completed surveys are due in this office on or before April 30. Non-response follow-up procedures are used to attain 100-percent response. Edit checks of the data are performed through computer programs. The 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.

Rounding Rules for Data. Not applicable.

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

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

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

Confidentiality of the Data. The unregulated entity data collected on Schedule 9, plant fuel cost data, of this 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 facility level costs.

Form EIA-767

The Form EIA-767 is 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 700 power plants with a nameplate capacity of 100 or more megawatts. An additional 600 power plants with a nameplate capacity under 100 megawatts submit information only on fuel consumption/quality, boiler/generator configuration, and flue gas desulfurization equipment, if applicable. 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).

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 these 200 additional plants complete only pages 1, 5, 6, and, if applicable, 13, and 14.

Data Processing and Data System Editing. The Form EIA-767 is mailed to respondents in January to collect data as of the end of the preceding calendar year. The completed forms are to be returned to the EIA by April 30. Equipment design data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data 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.

Rounding Rules for Data. Given a number with r digits to the left of the decimal and d+t digits in the fraction part, with d being the place to which the number is to be rounded and t being the remaining digits which will be truncated, this number is rounded to r+d digits by adding 5 to the (r+d+1)th digit when the number is positive or by subtracting 5 when the number is negative. The t digits are then truncated at the (r+d+1)th digit. The symbol for a number rounded to zero is (*).

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

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

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

Confidentiality of the Data. Most of the data collected on the Form EIA-860 are not considered confidential. However, plant latitudes and longitudes 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-860

Beginning with data collected for the year 2001, the Forms EIA-860A and EIA-860B are obsolete. The infrastructure data collected on those forms are now collected on the Form EIA-860 and the monthly and annual versions of the Form EIA-906.

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 is mailed to approximately 2,000 respondents to collect data as of January 1 of the reporting year. Respondents have the option of filing Form EIA-860 directly with the EIA or through an agent, such as the respondent's regional electric reliability council. Data reported through the regional electric reliability councils are submitted to the EIA electronically from the North American Electric Reliability Council (NERC).

Data for each respondent are preprinted. Respondents are instructed to verify all preprinted data and to supply missing data. Computer programs containing edit checks are run to identify errors. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the editing process.

Rounding Rules for Data. Not applicable.

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

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

where x (t1) and x (t2) denote the quantity at year t1 and subsequent year t2.

Confidentiality of the Data. Most of the data collected on the Form EIA-860 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-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 4,900 respondents. About 3,300 are electric utilities, and the remainder are nontraditional entities such as independent power producers, and the unregulated subsidiaries of electric utilities. The data collected are used to maintain and update the EIA's electric power industry participant frame database.

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 mailed to the respondents in January of each year to collect data as of the end of the preceding calendar year. The data are edited 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 and the EIA-412, "Annual Electric Industry Financial Report." 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.

Average revenue per kilowatthour represents the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average revenue per kilowatthour is calculated for all consumers and for each end-use sector. A ratio estimation procedure is used for estimation of revenue per kilowatthour at the State level.

The electric revenue used to calculate the average revenue per kilowatthour 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 State and Federal income taxes and taxes other than income taxes paid by the utility.

The average revenue per kilowatthour 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.

Rounding Rules for Data. Given a number with r digits to the left of the decimal and d+t digits in the fraction part, with d being the place to which the number is to be rounded and t being the remaining digits which will be truncated, this number is rounded to r+d digits by adding 5 to the (r+d+1)th digit when the number is positive or by subtracting 5 when the number is negative. The t digits are then truncated at the (r+d+1)th digit. The symbol for a number rounded to zero is (*).

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

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

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

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

Form EIA-906

As of January 2001, Form EIA-906 superseded Forms EIA-759 and 900. The Form EIA-906 is used to collect monthly plant-level data on generation, fuel consumption, stocks, fuel heat content, and useful thermal output from electric utilities and nonutilities from a model-based sample of approximately 260 electric utilities and 900 nonutilities. 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. 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 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. The Federal Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

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 PFC-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.

Data Processing and Data System Editing. In 2001 and 2002, the Form EIA-906 was received by the EIA as a hard copy, typically via fax, and manually 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).

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 CHP. 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 2000 and 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 2000 to 2001.

Overall, of the approximately 2600 facilities in the Form EIA-906 frame for 2001, 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.

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

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

Using the Central Limit Theorem, which applies to sums and means such as are applicable here, there is approximately a 68-percent chance that the true sampling error is less than the corresponding RSE. 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 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). There is approximately a 95-percent chance of a true sampling error being 2 RSEs or less.

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.

Adjusting Monthly Data to Annual Data. As a final adjustment based on our most complete data, use is made of annual Form EIA-906 data, when available. The annual totals of the monthly Form EIA-906 data by State and end-use sector are compared to the corresponding annual Form EIA-861 values for sales and revenue. The ratio of these two values in each case is then used to adjust each corresponding monthly value.

Average Heat Content. The average heat content values collected on the Form EIA-906 were used to convert the consumption data into Btu. Therefore, the results may not be completely representative.

Rounding Rules for Data. Given a number with r digits to the left of the decimal and d+t digits in the fraction part, with d being the place to which the number is to be rounded and t being the remaining digits which will be truncated, this number is rounded to r+d digits by adding 5 to the (r+d+1)th digit when the number is positive or by subtracting 5 when the number is negative. The t digits are then truncated at the (r+d+1)th digit. The symbol for a number rounded to zero is (*).

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

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

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

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)).

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 Btus.

Air Emissions

This section describes the methodology employed to calculate estimates of carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) emissions from electric generating plants.

The CO_2 air emissions are estimated using information contained on Form EIA-906, "Power Plant Report." The Form EIA-906 collects information from all electric power plants in the United States either monthly or annually. Data collected on this form include electric power generation, energy source consumption, and useful thermal output from combined heat and power producers. The Form EIA-906 sample of monthly respondents is a representation of electric power plants by State and by energy source. Electric power plants that do not report data monthly are to submit data annually on this form.

The SO_2 and NO_X air emissions are estimated using information contained on Form EIA-767, " Steam-Electric Plant Operation and Design Report." Form EIA-767 collects information annually for all U.S. power plants with a total existing or planned organic-fueled or combustible renewable steam-electric plant that has a generator nameplate rating of 10 megawatts or larger. If a plant has a nameplate capacity of 100 megawatts or greater, the entire form must be completed which provides information about fuel consumption and quality, legal air emission limits, and flue gas desulfurization (FGD). If a plant has a nameplate rating of 10 megawatts, but less than 100 megawatts, only part of the form must be completed which provides information on fuel consumption and quality, NO_X emission controls, and FGD sulfur removal efficiency, if applicable. The SO_2 and NO_X calculations are reduced for plants that have the Environmental Protection Agency's Continuous Emissions Monitoring System.

Uncontrolled Air Pollutant Emissions. Uncontrolled air pollutant emissions are those emissions that would occur in the absence of any control equipment. Uncontrolled CO_2, SO_2, and NO_X emissions are determined by multiplying the quantity of fuel burned by an emission factor. An emission factor is the average quantity of a pollutant released from a boiler when a unit of fuel is burned.

The coefficients for determining emissions of CO_2 from electric power plants come from the publication, Emissions of Greenhouse Gases in the United States, (DOE/EIA-0573). The source of the SO_2 and NO_X emission factors, when available, is the Environmental Protection Agency report AP-42, "Compilation of Air Pollutant Emission Factors" (Tables A1 and A3).[1] Emissions of SO_2 and NO_X have been revised from the updated Air Pollutant Emissions Factor (AP-42 5th edition, through Supplement E) of the Environmental Protection Agency on July 1999. Environmental Protection Agency emission factors are based on boiler type, firing configuration, and fuel burned.

Methodology

CO_2 emissions for power producers include emis sions from combined heat and power (CHP) facilities that produce electric power as an integral part of a manufacturing or other thermal consuming process. Emissions are directly proportional to the quantities of fuels consumed. To calculate emissions for the production of electricity, a methodology was developed to estimate the consumption of fuel associated for the production of electricity by CHP facilities. The methodology is based on the following:

1. A steam boiler efficiency rate of 80 percent was assumed.
2. The reported or estimated value for useful thermal output (in Btu) was divided by 0.8 to estimate the fuel used to generate this amount of thermal output.
3. This value was subtracted from total fuel consumption and the remainder was assumed to be the amount used for electric generation.

Coal Rank and Emissions. In 1992, a special study of the relationship between the heat and carbon content of coal was completed by the Energy Information Administration's Analysis and Systems Division of the Office of Coal, Nuclear, Electric and Alternate Fuels. The hypothesis underlying this study was that the ratio of carbon-to-heat content varies not only by coal rank (i.e., anthracite, bituminous, subbituminous, and lignite), but also by geographic location of the coal. In this study, the hypothesis was tested and the results of the analysis supported the hypothesis. That is, it was concluded from the analysis that coal rank and location of the coal are significant factors in the variation of the ratio of carbon-to-heat content. After this determination, a set of emission factors, by rank and State were derived on the basis of data contained in EIA's Coal Analysis File.[2]

[1] "Compilation of Air Pollutant Emission Factors, Vol. 1: Stationary Point and Area Sources (AP-42);" 5th Edition (through Supplement E) Research Triangle Park, North Carolina, July 1999.

[2] For a description of the methodology and data used to develop the EIA CO22 emission factors, see B. D. Hong and E. R. Slatick, "Carbon Dioxide Emission Factors for Coal," Quarterly Coal Report, January-March 1994,

In editions prior to 1992 of this publication, separate conversion factors by coal rank were published and used to estimate emissions of CO_2. The special study by EIA concluded that since geographic location of coal in addition to rank of coal is a significant factor in determining the carbon/heat content relationship, the use of emission factors that consider both of these elements may yield more accurate estimates of CO_2 emissions. The emission factors for coal were developed in the units of pounds of CO_2 per million Btu of coal.

The emission factors for CO_2 (Table A2) from coal are applied by power plant, based on the rank, amount of coal received, and the State from which the coal originated, as reported in FERC Form 423, "Cost and Quality of Fuels for Electric Plants." Thus, a weighted average emissions factor is obtained by plant and multiplied by the quantity of coal consumed by plant, as reported on Form EIA-906, "Power Plant Report," to determine the emissions of CO_2. The emission factors for CO_2 are based on 100-percent combustion of the carbon in the fuel. Since a small percentage of the carbon in the coal is not converted to CO_2, this publication assumes 99 percent combustion. The 1 percent of emissions is deducted at the State/National level. The emissions at the State level are based on the State in which the plant is located. Uncontrolled emissions of SO_2 and NO_X do not always accurately depict the quantity of emissions released into the atmosphere because they fail to reflect reductions from control equipment and/or operating technologies. Consequently, controlled emissions are calculated to provide a more accurate estimate of actual air emissions.

Controlled Sulfur Dioxide Emissions. Because of environmental regulations controlling SO_2 emissions, many generating plants are required to install FGD units at their coal-fired plants.[3] FGD units typically remove between 70 to 90 percent of SO_2 from the boiler flue gas although higher removal efficiencies can be achieved. Electric generating plants report both sulfur removal efficiency (percent) and their most stringent SO_2 emission limits on the Form EIA-767. To determine controlled SO_2 emissions, the uncontrolled emissions are reduced by the annual average removal efficiencies reported on the Form EIA-767. This emission is the controlled emission. As a check, the controlled emission is compared with the most stringent legal limit reported on the Form EIA-767. The controlled emission should be less than the legal limit because research indicates that electric generating plants routinely remove more SO_2 than required to assure an operating margin of safety. If the controlled emission is not less than the most stringent legal limit, it implies that the plant or facility is out of legal compliance and could be subject to fines and other penalties.

Electric generating plants are permitted to take credit for sulfur that remains in bottom ash – ash remaining in the bottom of the furnace after the coal is burned. For example, if a plant or facility is required to remove 90 percent of the sulfur in the coal and 3 percent remains in the ash, it has to remove only 87 percent using scrubbers. This credit is included in emissions data in this report. It is likely, however, that in many cases the credit is not taken. In order to take the ash credit, generating facilities need to monitor the coal consumed on a daily basis; this is both time-consuming and costly. To the extent that generating facilities do not take the ash credit, emissions might be slightly overstated.

Sulfur Dioxide Emission Comparison. Title IV of the Clean Air Act Amendments of 1990 requires annual sulfur dioxide (SO_2) emissions from electric power plants to be reduced 10 million tons below their 1990 level by the year 2010. The Clean Air Act required electric generating units covered under the Acid Rain Program (units 25 megawatts and greater) to be equipped with continuous emission monitoring systems (CEMS). CEMS is the industry standard for measuring and recording hourly SO_2, nitrogen oxide (NO_X), and carbon dioxide (CO_2) emissions. In 1994, the first 263 generating units covered under the Acid Rain Program were required to install CEMS and submit a year's worth of emissions data to the Environmental Protection Agency (EPA). In 1995, the operators of more than 2,000 additional units were required to measure and report emissions data. EPA started publishing CEMS emissions data by State and plant in its publication Acid Rain Program, Emissions Scorecard (EPA430/R-97-025).

Controlled Nitrogen Oxide Emissions. The controlled NO_X emission is calculated by applying the appropriate reduction factor in Table A4. Prior to 1995 for boilers with regulated nitrogen oxide emission limits, the annual controlled estimate used was the lesser of the controlled estimate or the annual limitation. When more than one control technology is reported, the highest single reduction factor is used to estimate the annual controlled NO_X emission. A degree of complexity is added to this approach, however, because air emission standards are not reported in consistent units. In some rare instances, emission standards are reported in units that cannot be directly compared with estimated uncontrolled emission rates. Examples of such standards are ones that specify the concentration of NO_X allowed in the flue gas or the ambient concentration of NO_X (parts per million). In cases where these types of standards are reported, the uncontrolled emission estimate is used. Such standards

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DOE/EIA-0121(94/1Q) (Washington, DC, August 1994), Energy Information Administration.

[3] Flue gas desulfurization units may also reduce sulfur dioxide emissions from plants that burn oil and petroleum coke.

are uncommon, however, and do not significantly affect the results.

Carbon Dioxide Emissions. There are no Federal regulations that limit CO_2 emissions. Information pertinent to the estimation of controlled CO_2 emissions is not collected on the Form EIA-767; therefore, no estimates of controlled CO_2 emissions are made.

Air Emissions from Small Plants. The Form EIA-767 does not collect data for generators powered by internal combustion engines, gas turbines, combined cycle units (for example, gas turbines with waste heat boilers), and boilers at steam-electric plants with a total nameplate capacity of less than 10 MW. Accordingly, air emissions from these generators are not estimated by the methodology. An estimate of air emissions from these generating units based on a similar methodology using consumption data reported on the Form EIA-906, "Power Plant Report," and predecessor forms was performed.

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
115 Agricultural services
114 Fishing, hunting, and trapping
113 Forestry
Mining
2122 Metal mining
2121 Coal mining
211 Oil and gas extraction
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
321 Lumber and wood products, except furniture
337 Furniture and fixtures
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
316 Leather and leather 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
335 Electronic and other electrical equipment and components except computer equipment
336 Transportation equipment
3345 Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
339 Miscellaneous manufacturing industries
Transportation and Public Utilities
482 Railroad transportation
485 Local and suburban transit and interurban highway passenger transport
484 Motor freight transportation and warehousing
491 United States Postal Service
483 Water transportation
481 Transportation by air
486 Pipelines, except natural gas
487 Transportation services
513 Communications
22 Electric, gas, and sanitary services
2212 Natural gas transmission
2213 Water supply
22132 Sewerage systems
562212 Refuse systems
22131 Irrigation systems
Wholesale Trade
421 to 422
Retail Trade
441 to 454

Finance, Insurance, and Real Estate
521 to 533
Services
721 Hotels
812 Personal services
514 Business services
8111 Automotive repair, services, and parking
811 Miscellaneous repair services
512 Motion pictures
713 Amusement and recreation services
622 Health services
541 Legal services
611 Education services
624 Social services
712 Museums, art galleries, and botanical and zoological gardens
813 Membership organizations
561 Engineering, accounting, research, management, and related services
814 Private households
514199 Miscellaneous services
Public Administration
92

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

Fuel	Boiler Type/ Firing Configuration	Emission Factors		
		Sulfur Dioxide[1]	Nitrogen Oxides[2]	Carbon Dioxide[3]
Electricity Generators				
Coal and Other Solid Fuels		Lbs per ton	Lbs per ton	Lbs per 10^6 Btu
Bituminous[4]	cyclone	38.00 x S	33.0	See Table A2
	fluidized bed[5]	31.00 x S	5.0	See Table A2
	spreader stoker	38.00 x S	11.0	See Table A2
	tangential	38.00 x S	15.0(14)	See Table A2
	all Others	38.00 x S	22.0(31)	See Table A2
Subbituminous	cyclone	35.00 x S	17.0	See Table A2
	fluidized bed[5]	31.00 x S	5.0	See Table A2
	spreader stoker	38.00 x S	8.8	See Table A2
	Tangential	35.00 x S	8.4	See Table A2
	all Others	35.00 x S	12.0(24)	See Table A2
Lignite	Cyclone	30.00 x S	15.00	See Table A2
	fluidized bed[5]	10.00 x S	3.60	See Table A2
	front/opposed	30.00 x S	13.00	See Table A2
	spreader stoker	30.00 x S	5.80	See Table A2
	tangential	30.00 x S	7.10	See Table A2
	all Others	30.00 x S	7.10(13)	See Table A2
Petroleum Coke[6]	fluidized bed[5]	39.00 x S	21.00	225.13
	all Others	39.00 x S	21.00	225.13
Refuse	all types	3.90	5.00	199.82
Wood	all types	0.08	1.50	0.00
Petroleum and Other Liquid Fuels		lbs per 10^3 gal	lbs per 10^3 gal	lbs per 10^6 Btu
Residual Oil[7]	Tangential	157.00 x S	32.0	173.72
	Vertical	157.00 x S	47.0	173.72
	all Others	157.00 x S	47.0	173.72
Distillate Oil[7]	all types	150.00 x S	24.0	161.27
Methanol	all types	See Table A3	See Table A3	138.15
Propane (liquid)	all types	86.5	19.00	139.04
Coal-Oil Mixture	all types	See Table A3	See Table A3	173.72
Natural Gas and Other Gaseous Fuels		lbs per 10^6 cf	lbs per 10^6 cf	lbs per 10^6 Btu
Natural Gas	Tangential	0.60	170.00	116.97
	all Others	0.60	280.00	116.97
Blast Furnace Gas	all types	950.00	280.00	116.97
Combined Heat and Power Producers				
Coal and Other Solid Fuels		lbs per ton	lbs per ton	lbs per 10^6 Btu
Anthracite Culms	all types	39.00 x S	1.80	See Table A2
Bituminous	all types	38.00 x S	22.0	See Table A2
Bituminous Gob	all types	38.00 x S	22.0	See Table A2
Subbituminous	all types	35.00 x S	12.0	See Table A2
Lignite	all types	30.00 x S	12.0	See Table A2
Lignite Waste	all types	30.00 x S	12.0	See Table A2
Peat	all types	30.00 x S	12.0	0
Agricultural Waste	all types	See Table A3	See Table A3	0
Black Liquor	all types	See Table A3	See Table A3	0
Chemicals	all types	See Table A3	See Table A3	0
Closed Loop Biomass	all types	See Table A3	See Table A3	0
Internal	all types	See Table A3	See Table A3	0

See footnotes at end of table.

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

Fuel	Boiler Type/ Firing Configuration	Emission Factors: Sulfur Dioxide[1]	Emission Factors: Nitrogen Oxides[2]	Emission Factors: Carbon Dioxide[3]
Coal and Other Solid Fuels (Continued)		**Lbs per ton**	**lbs per ton**	**lbs per 10^6 Btu**
Liquid Acetonitrile Waste	all types	See Table A3	See Table A3	150.76
Liquid Waste	all types	2.80	2.30	163.29
Municipal Solid Waste	all types	1.70	5.90	189.48
Petroleum Coke	all types	39.00 x S	14.00	225.13
Pitch	all types	See Table A3	See Table A3	0
RailRoad Ties	all types	See Table A3	See Table A3	0
Red Liquor	all types	See Table A3	See Table A3	0
Sludge	all types	2.80	5.00	0
Sludge Waste	all types	2.80	5.00	0
Sludge Wood	all types	2.80	5.00	0
Spent Sulfite Liquor	all types	See Table A3	See Table A3	0
Straw	all types	See Table A3	See Table A3	0
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	See Table A3	See Table A3	0
Tires	all types	See Table A3	See Table A3	0
Waste Byproducts	all types	1.70	2.30	163.29
Waste Coal	all types	See Table A3	See Table A3	0
Wood/Wood Waste	all types	0.08	1.50	0
Petroleum and Other Liquid Fuels		**lbs per 10^3 gal**	**lbs per 10^3 gal**	**lbs per 10^6 Btu**
Heavy Oil[7]	all types	157.00 x S	47.00	173.72
Light Oil[7]	all types	142.00 x S	20.00	159.41
Diesel	all types	142.00 x S	20.00	161.27
Kerosene	all types	142.00 x S	20.00	159.41
Butane (liquid)	all types	0.09	21.00	143.20
Fish Oil	all types	See Table A3	See Table A3	0
Methanol	all types	See Table A3	See Table A3	138.15
Oil Waste	all types	147.00 x S	19.00	163.61
Propane (liquid)	all types	0.50	19.00	139.04
Sludge Oil	all types	147.00 x S	19.00	0
Tar Oil	all types	See Table A3	See Table A3	0
Waste Alcohol	all types	See Table A3	See Table A3	138.15
Natural Gas and Other Gaseous Fuels		**lbs per 10^6 cf**	**lbs per 10^6 cf**	**lbs per 10^6 Btu**
Natural Gas	all types	0.60	280.00	116.97
Butane (Gas)	all types	0.60	21.00	143.20
Hydrogen	all types	See Table A3	550.00	0
Landfill Gas	all types	See Table A3	550.00	115.12
Methane	all types	See Table A3	550.00	115.11
Other Gas	all types	See Table A3	550.00	141.54
Propane (Gas)	all types	0.60	19.00	139.04

[1] Uncontrolled sulfur dioxide emission factors. "x S" indicates that the constant must be multiplied by the percentage (by weight) of sulfur in the fuel. Sulfur dioxide emission estimates from facilities with flue gas desulfurization equipment are calculated by multiplying uncontrolled emission estimates by one minus the reported sulfur removal efficiencies. Sulfur dioxide emission factors also account for small quantities of sulfur trioxide and gaseous sulfates.
[2] Parenthetic values are for wet bottom boilers; otherwise dry bottom boilers. If bottom type is unknown, dry bottom is assumed. Emission factors are for boilers with a gross heat rate of 100 million Btu per hour or greater. See Table A4 for nitrogen oxide reduction factors used to calculate controlled nitrogen oxide emission estimates.
[3] Uncontrolled carbon dioxide emission estimates are reduced by 1 percent to account for unburned carbon.
[4] Coal types are categorized by Btu content as follows: bituminous (greater than or equal to 9,750 Btu per pound), subbituminous (equal to 7,500 to 9,750 Btu per pound), and lignite (less than 7,500 Btu per pound).
[5] Sulfur dioxide emission estimates from fluidized bed boilers assume a sulfur removal efficiency of 90 percent.
[6] Emission factors for petroleum coke are assumed to be the same as those for anthracite. If the sulfur content of petroleumcoke is unknown, a 6 percent sulfur content is assumed.
[7] Oil types are categorized by Btu content as follows: heavy (greater than or equal to 144,190 Btu per gallon), and light (less than 144,190 Btu per gallon).

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. Sulfur Dioxide and Nitrogen Oxide Factors for Specific Fuels

Fuel	Boiler Type/ Firing Configuration	Emission Factors	
		Sulfur Dioxide[1]	Nitrogen Oxides[2]
Electricity Generators		**lbs per 10^3 gal**	**lbs per 10^3 gal**
Methanol	all types	0.05	12.40
Coal-Oil Mixture	all types	185.00 x S	50.00
Combined Heat and Power Producers		**lbs per ton**	**lbs per ton**
Agricultural Waste	all types	0.08	1.20
Black Liquor	all types	7.00	1.50
Chemicals	all types	7.00	1.50
Closed Loop Biomass	all types	0.08	1.50
Internal	all types	0.08	1.50
Liquid Acetonitrile Waste	all types	7.00	1.50
Pitch	all types	30.00 x S	11.10
Railroad Ties	all types	0.08	1.50
Red Liquor	all types	7.00	1.50
Spent Sulfite Liquor	all types	7.00	1.50
Straw	all types	0.08	1.50
Tar Coal	all types	30.00 x S	11.10
Tires	all types	38.00 x S	21.70
Waste Coal	all types	38.00 x S	21.70
		lbs per 10^3 gal	**lbs per 10^3 gal**
Fish Oil	all types	0.50	12.40
Methanol	all types	0.50	12.40
Tar Oil	all types	162.70 x S	67.00
Waste Alcohol	all types	0.50	12.40
		lbs per 10^6 cf	**lbs per 10^6 cf**
Hydrogen	all types	0.00	550.00
Landfill Gas	all types	0.60	550.00
Methane	all types	0.60	550.00
Other Gas	all types	0.60	550.00

[1] Uncontrolled sulfur dioxide emission factors. "x S" indicates that the constant must be multiplied by the percentage (by weight) of sulfur in the fuel. Sulfur dioxide emission estimates from facilities with flue gas desulfurization equipment are calculated by multiplying uncontrolled emission estimates by one minus the reported sulfur removal efficiencies. Sulfur dioxide emission factors also account for small quantities of sulfur trioxide and gaseous sulfates.

[2] If bottom type is unknown, dry bottom is assumed. Emission factors are for boilers with a gross heat rate of 100 million Btu per hour or greater. See Table A4 for nitrogen oxide reduction factors used to calculate controlled nitrogen emission estimates.

Sources: Nitrogen Oxide emission factors from Hydrogen, Landfill Gas, Methane, and Other Gas calculated from Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, Fifth Edition (through Supplement E), Research Triangle Park, North Carolina, July, 1999. All other fuels calculated by the Office of Integrated Analysis and Forecasting.

Table A4. Nitrogen Oxide Reduction Factors

Nitrogen Oxide Control Technology	EIA-767 Code(s)	EIA-860 Code(s)	Reduction Factor (Percent)
Advanced Overfire Air	AA	--	30[1]
Alternate Burners	BF	--	20
Flue Gas Recirculation	FR	FG	40
Fluidized Bed Combustor	CF	--	20
Fuel Reburning	FU	--	30
Low Excess Air	LA	LE	20
Low Nitrogen Oxide Burners	LN	LN	30[1]
Other (or Unspecified)	OT	OT	20
Overfire Air	OV	OA	20[1]
Selective Catalytic Reduction	SR	CC	70
Selective Catalytic Reduction With Low Nitrogen Oxide Burners	SR and LN	CC and LN	90
Selective Noncatalytic Reduction	SN	--	30
Selective Noncatalytic Reduction With Low Nitrogen Oxide Burners	SR and LN	--	50
Slagging	SC	--	20
Steam or Water Injection	--	SW	20

[1] Starting with 1995 data, reduction factors for advanced overfire air, low nitrogen oxide burners, and overfire air were reduced by 10.

Source: Babcock and Wilcox, Steam: Its Generation and Use, 40th Edition, 1992.

Table A5. Unit-of-Measure Equivalents

Unit	Equivalent		
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.

Appendix B

Estimating and Presenting Power Sector Fuel Use

I. Background

The Energy Information Administration (EIA) has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed inconsistent reporting of the fuels used for electric power and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications. For example:

- In some cases fuel use by combined-heat-and-power (CHP) plants[1] has been reported as industrial sector fuel use, while in other cases it has been reported as electric power sector fuel use.

- Electricity generation and fuel consumption have been categorized and reported in several different ways, such as (1) utility only; (2) utility and independent power producers; or (3) utility, independent power producers, and CHP plants. The restructuring of the power industry is making some of these categories less meaningful.

The goal of EIA's comprehensive review was to improve the quality and consistency of its electric power data throughout all data and analysis products. Because power facilities operate in all sectors of the economy (e.g., in commercial buildings, such as hospitals and college campuses, and industrial facilities, such as paper mills and refineries) and use many fuels, any change to electric power data affects data series in nearly all fuel areas and causes changes in a wide variety of EIA publications.

As a result of the comprehensive review, EIA has made the following changes:

- EIA has adjusted all presentations of data on electric power to a consistent format and defined the electric power sector to include electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public.
- EIA is providing detail within the electric power sector, commercial sector, and industrial sector on fuel used by CHP plants in those sectors.
- EIA has changed the sources of data on fuel used by components of the electric power sector. All tabulations and publications will use data obtained from EIA's surveys of electric power generators. This change in data source contributes to changes in total fuel consumption of natural gas.
- EIA has revised its historical data on electric power to resolve data anomalies. The revisions contribute to changes in EIA's electricity series as well as the fuel-use series.

Appendix B describes the reasoning behind the changes and their effect on electric power publications. It is organized as follows:

- Section II provides an overview of the key changes.
- Section III provides specific information for electric power publications.

The Annual Energy Review (AER) 2001, the first of the annual publications to be released with the new formats, provides detail on changes for publications on coal, natural gas, petroleum, renewable energy, and greenhouse gas emissions.

II. Overview of Key Changes

The many changes that will occur because of the fuel review generally fall into three broad categories: (1) the categorization of electric power facilities, (2) the reporting of combined-heat-and-power plant fuel use, and (3) data series revisions resulting from revised electric power fuel use estimates. Each of these areas is discussed below.

Categorization of Electric Power Facilities

Until the 1990s, most electric power generation and fuel use data could be meaningfully categorized into electric utilities and nonutility power producers.[2] Electric utilities were generally structured as vertically integrated[3] power companies that were

[1] Combined-heat-and-power plants (CHP) produce both electricity and useful thermal output. EIA formerly referred to these plants as cogenerators, but has determined that CHP better describes the facilities because some of the plants included in EIA's data do not produce heat and power in a sequential fashion, and as a result do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).
[2] For an example of this, see *Electric Power Annual 1998, Volume II,* DOE/EIA-0348(98)/2, December 1999.
[3] In this context "integrated" means that the company is involved in the three main sectors of the electric power business—generation, transmission, and distribution.

responsible for generating, transmitting, and distributing power to consumers within their franchised service territory. Nonutility power producers were generally independent generators—mostly combined-heat-and-power plants—that produced some power for their own use and sold the remainder to utilities for distribution to consumers. However, in recent years, many formerly integrated utilities have split apart, spinning off the generating part of their business into separate companies. Independent developers have built most of the new generating capacity that has been installed in recent years. As a result, the distinction between utility and nonutility power plants has become much less meaningful. In fact, a large portion of the growth in nonutility generation in recent years is due to the reclassification of utility power plants as nonutility power plants.

To reflect the changing industry structure, EIA is now organizing electric power generation and fuel use data into two new categories: electricity-only and combined-heat-and-power (CHP) plants. These categories separate power plants by function; i.e., power only or power plus thermal, rather than by ownership class.

Electricity-only plants represent all plants, whether owned by utilities or nonutilities that produce only electricity. CHP plants represent entities that produce both electricity and some form of thermal energy. Both categories will have some facilities that are owned by traditional utilities and independent companies.

In addition, EIA is now presenting data for an electric power sector that includes electricity-only plants and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public (North American Industry Classification System code 22). This contrasts with some previous data presentations in which the electric power sector included industrial and commercial CHP plants as well. Figure B1 provides an example from the Annual Energy Review (AER).

Figure B1. Electric Power Sector in AER 2001 and AER 2000

AER 2001

Electric Power Sector		
Electricity Only	CHP	Total

AER 2000

Electric Power Sector		
Electric Utilities	Nonutility Power Producers	Total

In some tables and publications, the electric power sector will continue to be broken down into electric utilities and independent power producers for customers who have expressed an interest in this breakout. For example, Table 8.1 of AER 2001 presents an electricity overview and shows data on net generation for electric utilities and independent power producers separately. It is the only table in AER 2001 that has this break-out (Figure B2).

Figure B2. Electric Utilities and Independent Power Producers are shown separately in Electricity Overview

Table 8.1 Electricity Overview, 1949-2001
(Billion Kilowatthours)

Year	Net Generation					
	Electric Power Sector 1			Commercial Sector 2	Industrial Sector 3	Total
	Electric Utilities	Independent Power Producers	Total			

[1]The electric power sector (electric utilities and independent power producers) comprises electricity-only and combined-heat-and-power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public—i.e., NAICS 22 plants. Due to the restructuring of the electric power sector, the sale of generation assets is resulting in a reclassification of plants from electric utilities to independent power producers.
[2]Commercial combined-heat-and-power (CHP) and commercial electricity-only plants. See Appendix G for commercial sector NAICS codes.
[3]Industrial combined-heat-and-power (CHP) and industrial electricity-only plants. Through 1988, includes industrial hydroelectric power only. See Appendix G for industrial sector NAICS codes.

Reporting of CHP Facility Fuel Use

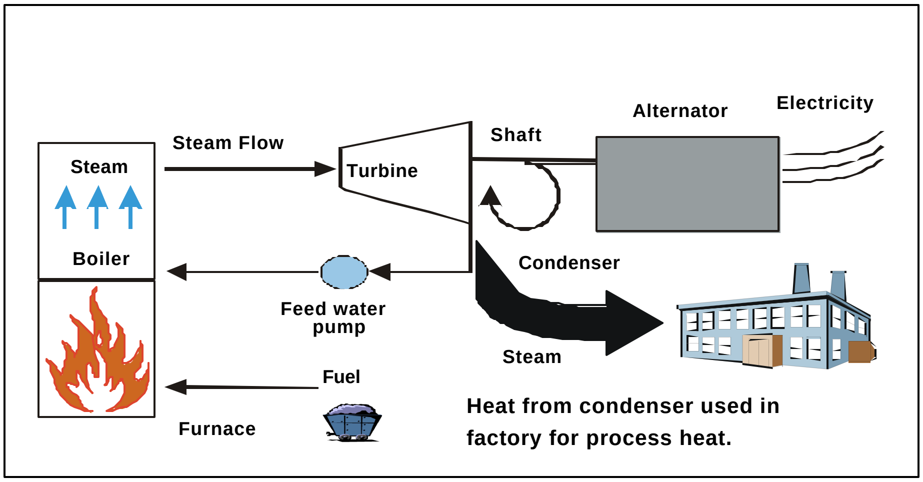
Historically, fuel consumption in CHP plants has been combined with other uses in many EIA publications. For example, in some tables the use of natural gas in commercial and industrial CHP plants was included with other commercial and industrial uses. Further, some of the fuel consumption (the portion associated with electricity production) at these same facilities was also reported under the column labeled "Nonutility Power Producers." Based on questions received, it became clear that this categorization led to confusion for many EIA customers.

EIA is now distinguishing within the industrial, commercial, and electric power sectors what portion of fuel consumption is used in CHP facilities and non-CHP facilities. For example:

- In tabulations of energy use by economic sector, if a commercial or industrial facility has a CHP unit, the total fuel consumption for that unit will be reported under commercial or industrial, but it will be identified separately from other commercial or industrial consumption. CHP plants that report their primary business is generating and selling power to others will be reported in a separate column in the electric power sector.

- In tabulations of energy use to produce electric power, the total fuel consumption reported by CHP plants will be further separated into that which is used to produce electricity and that which is used to produce thermal energy.[4] Figure B3 shows a schematic for combined heat and power producers.

Figure B3. Schematic for Combined Heat and Power Plants



The separation between electricity and thermal uses is being done because many EIA data users have expressed interest in knowing how much fuel is used to produce electricity in the United States.

Data Series Revisions Resulting From Changes in Electric Power Fuel Use Estimates

The revisions to electric power data affect many areas. For example, historically, to estimate natural gas use, EIA surveyed natural gas pipeline-companies and local gas utilities to obtain data on natural gas used by residential, commercial, industrial, and electric utility sectors, and nonutility generators.[5] However, EIA also surveyed electric utilities on their natural gas use. These data obtained directly from the end user were generally thought to be more accurate than the data obtained from natural gas suppliers. As a result, total natural gas use was estimated by adding together the data from natural gas companies on residential, commercial, industrial, and nonutility power producer use to the amount reported directly by electric utilities. The data collected for nonutility power producers were included with industrial use in previous EIA natural gas publications.

With the changing structure of the electricity sector, this reporting approach no longer appears reasonable. EIA has decided to follow the procedure described for electric utilities and use data obtained from its direct surveys of nonutility electric generators rather than the natural gas supplier surveys.[6]

[4] For the method used to separate the fuel used at CHP plants between electricity and useful thermal energy production, see Section III.
[5] Energy Information Administration, Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition."
[6] Energy Information Administration, Form EIA-759, "Monthly Power Plant Report" for electric utilities and Forms EIA-867 and EIA-860B, "Annual Electric Generator Report – Nonutility" for nonutilities. Starting with 2001, data for both utilities and nonutilities are collected on a new survey, Form EIA-906, "Power Plant Report."

Data changes are also occurring because of the extensive review of reported data that was undertaken in this process. Since it was decided that data reported directly by utilities and nonutility power generators would be the primary source of fuel consumption data for the power sector, an examination of heat rates,[7] capacity factors,[8] and power-to-steam ratios across 12 years of reported data was conducted. As a result, data for nonutility power producers for 1989 through 2000 have been revised. The data review procedure is described in Section III under the heading "Efforts to Improve Data." As a result of the review by expert EIA analysts, anomalous values have been investigated and resolved and the result is higher quality data at aggregated levels.

Revisions resulting from changing the source of fuel consumption data for nonutilities and from EIA's data review affect data beyond the category of nonutilities. Appendix H of AER 2001 provides examples.

III. Electric Power Surveys and Publications

Summary of Key Changes

EIA previously presented data on electric power, such as generation and fuel consumption, in the following categories:

- Electric utilities,
- Nonutility power producers (independent power producers and combined-heat-and power plants),
- Electric power industry (sum of electric utilities and nonutility power producers).

Now EIA is presenting data for the following new categories:

- Electricity-only-plants
- Combined-heat-and-power (CHP) plants,
- U.S. power producers (sum of electricity-only plants and CHP plants and equal to the prior "electric power industry" category).

Data on electricity-only plants are disaggregated for utilities and independent power producers, as there are customers who are interested in maintaining this distinction. Data on CHP plants are disaggregated by the end-use category (commercial, industrial, electric power) they report as their major line of business. The categorization is based on their North American Industrial Classification System code. For example, a CHP plant that is part of a hospital will be classified as "commercial." Similarly, a CHP plant that reports that it is part of a paper mill will be classified as "industrial," and a plant that reports that its primary business is selling power to others will be classified as "electric power."

In addition, EIA has estimated and is presenting data on the amount of fuel used to generate electricity and the amount of fuel used for useful thermal output. Furthermore, during the course of recategorizing the data, EIA performed a thorough data quality review and revised data to resolve anomalies.

Efforts to Improve Data

EIA reviewed electric power-data from 1989 through 2001 to determine whether there were anomalies. The 1989–2000 data for nonutilities were from Form EIA-860B, "Annual Electric Generator Report-Nonutility," and its predecessor, Form EIA-867, "Annual Nonutility Power Producer Report." The 2001 data are from Form EIA-906, "Power Plant Report." These forms collect data on fuel consumption, generation, and, with the exception of 1995 through 1997, useful thermal output. When anomalies were identified in the data for the more recent years (1998–2001), EIA contacted selected respondents to resolve the inconsistencies. For the historical data it was not possible to contact respondents. In this situation EIA made data adjustments to resolve the anomalies.

EIA reviewed data for facilities with heat rates greater than 40,000 Btu per kilowatthour and less than 5,500 Btu per kilowatthour. The upper limit was chosen to allow for the heat rates of older non-electricity boilers. In addition, EIA reviewed data for facilities with overall efficiency of greater than 100 percent and identified facilities with thermal output that were not designated as CHP plants. To ensure consistency, EIA compared North American Industry Classification System (NAICS) codes, cogenerator status, fuel consumption, electric generation, and thermal output levels over time. Moreover, EIA analysts also reviewed and evaluated aggregate-level data by State, NAICS code, fuel type, and generator type. For the historical data (1989–1997), EIA also:

[7] Heat rates are computed by dividing the heat content of the fuel burned to generate electricity by the resulting net kilowatthour generation.
[8] Capacity factors are the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

- Estimated a value for useful thermal output for 1995 through 1997 (when useful thermal output was not included on the survey form) that produced a heat rate between 5,500 and 40,000 Btu per kilowatthour and an efficiency rate consistent with that observed in other years (see discussion below on CHP fuel use methodology).
- Corrected errors in units reported for fuel consumption.
- Compared data on fuel consumption with data on electric generation and adjusted data on fuel consumption or generation to maintain a consistent ratio.
- Adjusted data on useful thermal output for those respondents with heat rates outside the 5,500-to-40,000 Btu per kilowatthour range and an efficiency rate consistent with other years.

The review included an examination of both respondent-level data and aggregate-level data. For the 1998-2000 data, the review also included a comparison for consistency with data reported by manufacturing plants on Form EIA-3, "Quarterly Coal Consumption—Manufacturing Plants," since a subset of the EIA-3 manufacturing plants generate electricity and also reported on the electric generator survey Form EIA-860B. In general, there was good correspondence between the data submissions. In situations where there were inconsistencies, selected respondents were contacted to explain the differences. The analysis revealed that in some instances there were legitimate explanations for high percentage differences, such as a respondent reporting data for a facility on one survey that should not be included in the other survey.

Allocating CHP Fuel Use

Because respondents do not keep records on how much fuel a CHP plant uses exclusively to produce electricity, EIA developed the following method for estimating how the total fuel consumed in the boiler is split between electricity generation and useful thermal output:

- First, a steam boiler efficiency rate of 80 percent was assumed[9]
- Then the reported or estimated value for useful thermal output (in Btu) was divided by 0.8 to estimate the fuel used to generate this amount of thermal output.
- Next, this value was subtracted from total fuel consumption and the remainder was assumed to be the amount used for electric generation.

Electric Power Publication Tables Affected

In both the *Electric Power Monthly* and the *Electric Power Annual*:

- Data will be shown for the following categories throughout most of the report: (1) U.S. power producers, (2) electricity-only plants, and (3) CHP plants (commercial, industrial, and electric power). Data on fuel consumption are shown for both electric generation and thermal output.
- The lowest level of aggregation is at the State level.
- Data on petroleum coke are converted to barrels and included in petroleum consumption and stocks tables.
- Fuel types are revised to be consistent with the Annual Energy Review.

[9] Arthur D. Little, Report to the Energy Information Administration, *Industrial Model: Update on Energy Use and Industrial Characteristics,* (September 2001), Appendix C, "Average Boiler Efficiencies."

Glossary

Anthracite: The highest rank of coal; used primarily for residential and commercial space heating. It is a hard, brittle, and black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. The moisture content of fresh-mined anthracite generally is less than 15 percent. The heat content of anthracite ranges from 22 to 28 million Btu per ton on a moist, mineral-matter-free basis. The heat content of anthracite coal consumed in the United States averages 25 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter). *Note:* Since the 1980's, anthracite refuse or mine waste has been used for steam electric power generation. This fuel typically has a heat content of 15 million Btu per ton or less.

Ash: Impurities consisting of silica, iron, aluminum, and other noncombustible matter that are contained in coal. Ash increases the weight of coal, adds to the cost of handling, and can affect its burning characteristics. Ash content is measured as a percent by weight of coal on a "received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Ash Content: The amount of ash contained in the fuel (except gas) in terms of percent by weight.

Average Revenue per Kilowatthour: The average revenue per kilowatthour of electricity sold by sector (residential, commercial, industrial, or other) and geographic area (State, Census division, and national), is calculated by dividing the total monthly revenue by the corresponding total monthly sales for each sector and geographic area.

Barrel: A unit of volume equal to 42 U.S. gallons.

Biomass: Organic non-fossil material of biological origin constituting a renewable energy resource.

Bituminous Coal: A dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material, used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke. Bituminous coal is the most abundant coal in active U.S. mining regions. Its moisture content usually is less than 20 percent. The heat content of bituminous coal ranges from 21 to 30 million Btu per ton on a moist, mineral-matter-free basis. The heat content of bituminous coal consumed in the United States averages 24 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

British Thermal Unit: The quantity of heat required to raise the temperature of 1 pound of liquid water by 1 degree Fahrenheit at the temperature at which water has its greatest density (approximately 39 degrees Fahrenheit).

Btu: The abbreviation for British thermal unit(s).

Capacity: See Generator Capacity and Generator Name Plate Capacity (Installed).

Census Divisions: Any of nine geographic areas of the United States as defined by the U.S. Department of Commerce, Bureau of the Census. The divisions, each consisting of several States, are defined as follows:

1) *New England:* Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont;
2) *Middle Atlantic*: New Jersey, New York, and Pennsylvania;
3) *East North Central:* Illinois, Indiana, Michigan, Ohio, and Wisconsin;
4) *West North Central*: Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota;
5) *South Atlantic*: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia;
6) *East South Central*: Alabama, Kentucky, Mississippi, and Tennessee;
7) *West South Central:* Arkansas, Louisiana, Oklahoma, and Texas;
8) *Mountain:* Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming;
9) *Pacific:* Alaska, California, Hawaii, Oregon, and Washington.

Note: Each division is a sub-area within a broader Census Region. In some cases, the Pacific division is subdivided into the Pacific Contiguous area (California, Oregon, and Washington) and the Pacific Noncontiguous area (Alaska and Hawaii).

Coal: A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time.

Coke (Petroleum): A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion is 5 barrels (of 42 U.S. gallons each) per short ton. Coke from petroleum has a heating value of 6.024 million Btu per barrel.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbine-generators. The exiting heat from the combustion turbine(s) is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of additional electricity.

Combined Heat and Power (CHP): Includes plants designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Commercial Sector: An energy-consuming sector that consists of service-providing facilities and equipment of: businesses; Federal, State, and local governments; and other private and public organizations, such as religious, social, or fraternal groups. The commercial sector includes institutional living quarters. It also includes sewage treatment facilities. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a wide variety of other equipment. *Note:* This sector includes generators that produce electricity and/or useful thermal output primarily to support the activities of the above-mentioned commercial establishments.

Consumption (Fuel): The use of energy as a source of heat or power or as a raw material input to a manufacturing process.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Utilities Service (prior Rural Electrification Administration), U.S. Department of Agriculture.

Cost: The amount paid to acquire resources, such as plant and equipment, fuel, or labor services.

Delivery-Only Service: Only services that involve the distribution of energy to retail customers, where another entity supplies the energy to be delivered.

Demand (Electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

Demand-Side Management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Diesel: A distillate fuel oil that is used in diesel engines such as those used for transportation and for electric power generation.

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation.

1) *No. 1 Distillate:* A light petroleum distillate that can be used as either a diesel fuel (see No. 1 Diesel Fuel) or a fuel oil. See No. 1 Fuel Oil.

    - *No. 1 Diesel Fuel:* A light distillate fuel oil that has distillation temperatures of 550 degrees Fahrenheit at the 90-percent point and meets the specifications defined in ASTM Specification D 975. It is used in high-speed diesel engines, such as those in city buses and similar vehicles. See No. 1 Distillate above.

    - *No. 1 Fuel Oil:* A light distillate fuel oil that has distillation temperatures of 400 degrees Fahrenheit at the 10-percent recovery point and 550 degrees Fahrenheit at the 90-percent point and meets the specifications defined in ASTM Specification D 396. It is used primarily as fuel for portable outdoor stoves and portable outdoor heaters. See No. 1 Distillate above.

2) *No. 2 Distillate:* A petroleum distillate that can be used as either a diesel fuel (see No. 2 Diesel Fuel definition below) or a fuel oil. See No. 2 Fuel oil below.

    - *No. 2 Diesel Fuel:* A fuel that has distillation temperatures of 500 degrees Fahrenheit at the 10-percent recovery point and 640 degrees Fahrenheit at the 90-percent recovery point and meets the specifications defined in ASTM Specification D 396. It is used in atomizing type burners for domestic heating or for moderate capacity commercial/industrial burner units. See No. 2 Distillate above.

3) *No. 4 Fuel:* A distillate fuel oil made by blending distillate fuel oil and residual fuel oil stocks. It conforms with ASTM Specification D 396 or Federal Specification VV-F-815C and is used extensively in industrial plants and in commercial burner installations that are not equipped with preheating facilities. It also includes No. 4 diesel fuel used for low- and medium-

speed diesel engines and conforms to ASTM Specification D 975.

- *No. 4 Diesel Fuel and No. 4 Fuel Oil*: See No. 4 Fuel above.

Distribution System: The portion of the transmission and facilities of an electric system that is dedicated to delivering electric energy to an end-user.

Electric Industry Restructuring: The process of replacing a monopolistic system of electric utility suppliers with competing sellers, allowing individual retail customers to choose their supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of vertically integrated electric utilities.

Electric Plant (Physical): A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric Power Sector: An energy-consuming sector that consists of electricity-only and combined-heat-and-power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public-- i. e., North American Industry Classification System 22 plants.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included. *Note:* Due to the issuance of FERC Order 888 that required traditional electric utilities to functionally unbundle their generation, transmission, and distribution operations, "electric utility" currently has inconsistent interpretations from State to State.

Electricity: A form of energy characterized by the presence and motion of elementary charged particles generated by friction, induction, or chemical change.

Electricity Generation: The process of producing electric energy or the amount of electric energy produced by transforming other forms of energy, commonly expressed in kilowatthours (kWh) or megawatthours (MWh).

Electricity Generators: The facilities that produce only electricity, commonly expressed in kilowatthours (kWh) or megawatthours (MWh).

1) *Electric Utility* – A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included. *Note:* Due to the issuance of FERC Order 888 that required traditional electric utilities to functionally unbundle their generation, transmission, and distribution operations, "electric utility" currently has inconsistent interpretations from State to State.

2) *Independent Power Producer* – A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and is not an electric utility.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units.

Energy Conservation Features: This includes building shell conservation features, HVAC conservation features, lighting conservation features, any conservation features, and other conservation features incorporated by the building. However, this category does not include any demand-side management (DSM) program participation by the building. Any DSM program participation is included in the DSM Programs.

Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatthours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Service Provider: An energy entity that provides service to a retail or end-use customer.

Energy Source: Any substance or natural phenomenon that can be consumed or transformed to supply heat or power. Examples include petroleum, coal, natural gas, nuclear, biomass, electricity, wind, sunlight, geothermal, water movement, and hydrogen in fuel cells.

Energy-Only Service: Retail sales services for which the company provided only the energy consumed, where another entity provides delivery services.

Federal Power Authority: Any of several federal agencies, operating under the U.S. Department of Energy, primarily involved in generating electricity, marketing wholesale electrical power, and operating and marketing transmission services.

Flue Gas Desulfurization: Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Also referred to as scrubbers. Chemicals such as lime are used as scrubbing media.

Flue-Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals such as lime are used as the scrubbing media.

Flue-Gas Particulate Collector: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Fossil Fuel: An energy source formed in the earths crust from decayed organic material. The common fossil fuels are petroleum, coal, and natural gas.

Franchised Service Area: A specified geographical area in which a utility has been granted the exclusive right to serve customers. A franchise allows an entity to use city streets, alleys and other public lands in order to provide, distribute, and sell services to the community.

Fuel: Any material substance that can be consumed to supply heat or power. Included are petroleum, coal, and natural gas (the fossil fuels), and other consumable materials, such as uranium, biomass, and hydrogen.

Full Service Provi der: An utility/company that provides both energy and delivery services of retail sales to ultimate consumers.

Gas: A fuel burned under boilers and by internal combustion engines for electric generation. These include natural, manufactured and waste gas.

Gas Turbine Plant: An electric generating facility in which the prime mover is a gas (combustion) turbine. A gas turbine typically consists of an air compressor and one or more combustion chambers where either liquid or gaseous fuel is burned. The resulting hot gases are passed through the turbine where they expand to drive both an electric generator and the compressor.

Generating Unit: Any combination of physically connected generators, reactors, boilers, combustion turbines, or other prime movers operated together to produce electric power.

Generator: A machine that converts mechanical energy into electrical energy.

Generator Capacity: The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions.

Generator Nameplate Capacity (Installed): The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.

Geothermal: Pertaining to heat within the Earth.

Geothermal Energy: Hot water or steam extracted from geothermal reservoirs in the earth's crust. Water or steam extracted from geothermal reservoirs can be used for geothermal heat pumps, water heating, or electricity generation.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Grid: The layout of an electrical distribution system.

Gross Generation: The total amount of electric energy produced by generating units and measured at the generating terminal in kilowatthours (kWh) or megawatthours (MWh).

Heat Content: The amount or number of British thermal units (Btu) produced by the combustion of fuel, measured in Btu/unit of measure.

Hydroelectric Power: The production of electricity from the kinetic energy of falling water.

Hydroelectric Power Generation: Electricity generated by an electric power plant whose turbines are driven by falling water. It includes electric utility and industrial generation of hydroelectricity, unless otherwise specified. Generation is reported on a net basis, i.e., on the amount of electric energy generated after the electric energy consumed by station auxiliaries and the losses in the transformers that are considered integral parts of the station are deducted.

Hydroelectric Pumped Storage: Hydroelectricity that is generated during peak loads by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Hydrogen: A colorless, odorless, highly flammable gaseous element. It is the lightest of all gases and the most abundant element in the universe, occurring chiefly in combination with oxygen in water and also in acids, bases, alcohols, petroleum, and other hydrocarbons.

Incremental Effects: The annual changes in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused by new participants in existing DSM (Demand-Side Management) programs and all participants in new DSM programs during a given year. Reported Incremental Effects are annualized to indicate the program effects that would have occurred had these participants been initiated into the program on January 1 of the given year. Incremental effects are not simply the Annual Effects of a given year minus the Annual Effects of the prior year, since these net effects would fail to account for program attrition, equipment degradation, building demolition, and participant dropouts. Please note that Incremental Effects are not a monthly disaggregate of the Annual Effects, but are the total year's effects of only the new participants and programs for that year.

Independent Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.

Industrial Sector: An energy-consuming sector that consists of all facilities and equipment used for producing, processing, or assembling goods. The industrial sector encompasses the following types of activity: manufacturing (NAICS codes 31-33); agriculture, forestry, and fisheries (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); natural gas transmission (NAICS code 2212); and construction (NAICS code 23). Overall energy use in this sector is largely for process heat and cooling and powering machinery, with lesser amounts used for facility heating, air conditioning, and lighting. Fossil fuels are also used as raw material inputs to manufactured products. *Note:* This sector includes generators that produce electricity and/or useful thermal output primarily to support the above-mentioned industrial activities.

Interdepartmental Service (Electric): Interdepartmental service includes amounts charged by the electric department at tariff or other specified rates for electricity supplied by it to other utility departments.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal types used in electric plants. The plant is usually operated during periods of high demand for electricity.

Investor-Owned Utility (IOU): A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

Jet Fuel: A refined petroleum product used in jet aircraft engines. It includes kerosene-type jet fuel and naphtha-type jet fuel.

Kerosene: A light petroleum distillate that is used in space heaters, cook stoves, and water heaters and is suitable for use as a light source when burned in wick-fed lamps. Kerosene has a maximum distillation temperature of 400 degrees Fahrenheit at the 10-percent recovery point, a final boiling point of 572 degrees Fahrenheit, and a minimum flash point of 100 degrees Fahrenheit. Included are No. 1-K and No. 2-K, the two grades recognized by ASTM Specification D 3699 as well as all other grades of kerosene called range or stove oil, which have properties similar to those of No. 1 fuel oil.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Light Oil: Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil.

Lignite: The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It is brownish-black and has a high inherent moisture content, sometimes as high as 45 percent The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis. The heat content of lignite consumed in the United States averages 13 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Management Techniques: Utility demand management practices directed at reducing the maximum kilowatt demand on an electric system and/or modifying the coincident peak demand of one or more classes of service to better meet the utility system capability for a given hour, day, week, season, or year.

Manufactured Gas: A gas obtained by destructive distillation of coal, or by thermal decomposition of oil, or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke oven gases, producer gas, blast furnace gas, blue (water) gas, and carbureted water gas

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts of electricity.

Megawatthour (MWh): One million watthours.

Municipal Utility: A nonprofit utility, owned by a local municipality and operated as a department thereof, governed by a city council or an independently elected or appointed board; primarily involved in the distribution and/or sale of retail electric power.

Natural Gas: A gaseous mixture of hydrocarbon compounds, the primary one being methane. *Note:* The Energy Information Administration measures wet natural gas and its two sources of production, associated/dissolved natural gas and nonassociated natural gas, and dry natural gas, which is produced from wet natural gas.

1) *Wet Natural Gas:* A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium. Under reservoir conditions, natural gas and its associated liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at the time as separate substances. *Note*: The Securities and Exchange Commission and the Financial Accounting Standards Board refer to this product as natural gas.

    - Associated-dissolved natural gas: Natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved gas).
    - Nonassociated natural gas: Natural gas that is not in contact with significant quantities of crude oil in the reservoir.

2) *Dry Natural Gas*: Natural gas which remains after: 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and 2) any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable. *Note*: Dry natural gas is also known as consumer-grade natural gas. The parameters for measurement are cubic feet at 60 degrees Fahrenheit and 14.73 pounds per square inch absolute.

Net Generation: The amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. *Note*: Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation.

Net Summer Capacity: The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of May 1 through October 31). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Net Winter Capacity: The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak winter demand (period of November 1 though April 30). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC Regions are:

1) ECAR – East Central Area Reliability Coordination Agreement
2) ERCOT – Electric Reliability Council of Texas
3) FRCC – Florida Reliability Coordinating Council
4) MAIN – Mid-America Interconnected Network
5) MAAC – Mid-Atlantic Area Council
6) MAPP – Mid-Continent Area Power Pool
7) NPCC – Northeast Power Coordinating Council
8) SERC – Southeastern Electric Reliability Council
9) SPP – Southwest Power Pool
10) WSCC – Western Systems Coordinating Council

North American Industry Classification System (NAICS): A set of codes that describes the possible purposes of a facility.

Nuclear Electric Power: Electricity generated by an electric power plant whose turbines are driven by steam produced by the heat from the fission of nuclear fuel in a reactor.

Other Customers: Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, sales for irrigation, and interdepartmental sales.

Other Generation: Electricity originating from these sources: manufactured, supplemental gaseous fuel, propane, and waste gasses, excluding natural gas; biomass; geothermal; wind; solar thermal; photovoltaic; synthetic fuel; purchased steam; and waste oil energy sources.

Percent Change: The relative change in a quantity over a specified time period. It is calculated as follows: the current value has the previous value subtracted from it; this new number is divided by the absolute value of the previous value; then this new number is multiplied by 100.

Petroleum: A broadly defined class of liquid hydrocarbon mixtures. Included are crude oil, lease condensate, unfinished oils, refined products obtained from the processing of crude oil, and natural gas plant liquids. *Note:* Volumes of finished petroleum products include nonhydrocarbon compounds, such as additives and detergents, after they have been blended into the products.

Petroleum Coke: See Coke (Petroleum).

Photovoltaic Energy: Direct-current electricity generated from sunlight through solid-state semiconductor devices that have no moving parts.

Plant: A term commonly used either as a synonym for an industrial establishment or a generation facility or to refer to a particular process within an establishment.

Potential Peak Reduction: The potential annual peak load reduction (measured in kilowatts) that can be deployed from Direct Load Control, Interruptible Load, Other Load Management, and Other DSM Program activities. (Please note that Energy Efficiency and Load Building are not included in Potential Peak Reduction.) It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Power Production Plant: All the land and land rights, structures and improvements, boiler or reactor vessel equipment, engines and engine-driven generator, turbo generator units, accessory electric equipment, and miscellaneous power plant equipment are grouped together for each individual facility.

Production (Electric): Act or process of producing electric energy from other forms of energy; also, the amount of electric energy expressed in watthours (Wh).

Propane: A normally gaseous straight-chain hydrocarbon, (C_3H_8). It is a colorless paraffinic gas that boils at a temperature of -43.67 degrees Fahrenheit. It is extracted from natural gas or refinery gas streams. It includes all products covered by Gas Processors Association Specifications for commercial propane and HD-5 propane and ASTM Specification D 1835.

Public Street and Highway Lighting Service: Includes electricity supplied and services rendered for the purpose of lighting streets, highways, parks and other public places; or for traffic or other signal system service, for municipalities, or other divisions or agencies of State or Federal governments.

Publicly Owned Electric Utility: A class of ownership found in the electric power industry. This group includes those utilities operated by municipalities and State and Federal power agencies.

Purchased Power: Power purchased or available for purchase from a source outside the system.

Railroad and Railway Electric Service: Electricity supplied to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules.

Receipts: Purchases of fuel.

Relative Standard Error: The standard deviation of a distribution divided by the arithmetic mean, sometimes multiplied by 100. It is used for the purpose of comparing the variabilities of frequency distributions but is sensitive to errors in the means.

Residential: An energy-consuming sector that consists of living quarters for private households. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a variety of other appliances. The residential sector excludes institutional living quarters.

Residual Fuel Oil: A general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. It conforms to ASTM Specifications D 396 and D 975 and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore powerplants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Revenues: The total amount of money received by a firm from sales of its products and/or services, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owner's equity except those arising from capital adjustments.

Sales: The transfer of title to an energy commodity from a seller to a buyer for a price or the quantity transferred during a specified period.

Sales for Resale: A type of wholesale sales covering energy supplied to other electric utilities, cooperatives, municipalities, and Federal and state electric agencies for resale to ultimate consumers.

Service Classifications (Sectors): Consumers grouped by similar characteristics in order to be identified for the purpose of setting a common rate for electric service. Usually classified into groups identified as residential, commercial, industrial and other.

Service to Public Authorities: Public authority service includes electricity supplied and services rendered to municipalities or divisions or agencies of State and Federal governments, under special contracts or agreements or service classifications applicable only to public authorities.

Solar Energy: The radiant energy of the sun that can be converted into other forms of energy, such as heat or electricity. Electricity produced from solar energy heats a medium that powers an electricity-generating device.

State Power Authority: A nonprofit utility owned and operated by a state government agency, primarily involved in the generation, marketing, and/or transmission of wholesale electric power.

Steam-Electric Power Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Stocks of Fuel: A supply of fuel accumulated for future use. This includes coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or in separate storage sites.

Subbituminous Coal: A coal whose properties range from those of lignite to those of bituminous coal and used primarily as fuel for steam-electric power generation. It may be dull, dark brown to black, soft and crumbly, at the lower end of the range, to bright, jet black, hard, and relatively strong, at the upper end. Subbituminous coal contains 20 to 30 percent inherent moisture by weight. The heat content of subbituminous coal ranges from 17 to 24 million Btu per ton on a moist, mineral-matter-free basis. The heat content of subbituminous coal consumed in the United States averages 17 to 18 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Sulfur: A yellowish nonmetallic element, sometimes known as "brimstone." It is present at various levels of concentration in many fossil fuels whose combustion releases sulfur compounds that are considered harmful to the environment. Some of the most commonly used fossil fuels are categorized according to their sulfur content, with lower sulfur fuels usually selling at a higher price. *Note*: No. 2 Distillate fuel is currently reported as having either a 0.05 percent or lower sulfur level for on-highway vehicle use or a greater than 0.05 percent sulfur level for off-highway use, home heating oil, and commercial and industrial uses. Residual fuel, regardless of use, is classified as having either no more than 1 percent sulfur or greater than 1 percent sulfur. Coal is also classified as being low- sulfur at concentrations of 1 percent or less or high-sulfur at concentrations greater than 1 percent.

Sulfur Content: The amount of sulfur contained in the fuel (except gas) in terms of percent by weight.

Supplemental Gaseous Fuel Supplies: Synthetic natural gas, propane-air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Synthetic Fuel: A gaseous, liquid, or solid fuel that does not occur naturally. Synfuels can be made from coal (coal gasification or coal liquefaction), petroleum products, oil shale, tar sands, or plant products. Among the synfuels are various fuel gases, including but not restricted to substitute natural gas, liquid fuels for engines (e.g., gasoline, diesel fuel, and alcohol fuels) and burner fuels (e.g., fuel heating oils).

Terrawatt: One trillion watts.

Terrawatthour: One trillion kilowatthours.

Ton: A unit of weight equal to 2,000 pounds.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Two-Party Wheeling: An arrangement between two entities in which one entity agrees to transmit electricity owned by the other.

Ultimate Consumer: A consumer that purchases electricity for its own use and not for resale.

Useful Thermal Output: The thermal energy made available in a combined heat or power system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

Waste Coal: As a fuel for electric power generation, waste coal includes anthracite refuse or mine waste, waste from anthracite preparation plants, and coal recovered from previously mined sites.

Waste Gases: As a fuel for electric power generation, waste gasses are those gasses that are produced from gasses recovered from a solid-waste or wastewater treatment facility, or the gaseous by-products of oil-refining processes.

Waste Oil: As a fuel for electric power generation, waste oil includes recycled motor oil, and waste oil from transformers.

Watt (W): The unit of electrical power equal to one ampere under a pressure of one volt. A Watt is equal to 1/746 horsepower.

Watthour (Wh): The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

Wind Energy: The kinetic energy of wind converted into mechanical energy by wind turbines (i.e., blades rotating from the hub) that drive generators to produce electricity.

Year to Date: The cumulative sum of each month's value starting with January and ending with the current month of the data.