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Electric Power Annual 2003

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Contacts

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Revenue and Expense Statistics
Karen McDaniel (202/287-1754)
e-mail: karen.mcdaniel@eia.doe.gov;
Thomas J. Leckey (202/287-1840)
e-mail: thomas.leckey@eia.doe.gov;

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

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The Energy Information Administration is committed to quality products and quality service. To ensure that this report meets the highest standards for quality, please forward your comments or suggestions about this publication to Robert Schnapp at 202/287-1787, or Internet e-mail: robert.schnapp@eia.doe.gov.

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

Preface

The Electric Power Annual 2003 presents a summary of electric power industry statistics at the national level. The objective of the publication is to provide industry decision-makers, government policymakers, analysts, and the general public with historical data that may be used in understanding U.S. electricity markets. The *Electric Power Annual* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy.

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

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

The *Electric Power Annual* presents an overview of the electric power industry in the United States and a summary of the key statistics for the reporting year. The chapters present information and data in each specific area: electricity generation; electric generating capacity; demand, capacity resources, and capacity margins; fuel, consumption and receipts; emissions; electricity trade; retail electric customers, sales, revenue and average retail price; electric utility revenue and expense statistics; and demand-side management. Monetary values in this publication are expressed in nominal terms.

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

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Electric Power Industry 2003: Year in Review

Industry Profile

The electric power industry in the United States is composed of electric utilities[1] whose rate schedules are regulated, as well as nonutilities[2] that offer market-based rates.

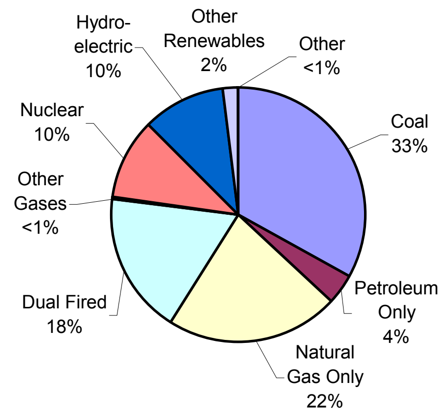
The majority of nonutilities, independent power producers (IPP)[3] and combined heat and power plants (CHP)[4], maintain the capability to generate electricity but are not generally aligned with distribution facilities. There are approximately 2,800 independent power producers and combined heat and power plants in the United States.

Capacity

As of January 1, 2004, total net summer generating capacity in the United States was 948 gigawatts, an increase of 4.8 percent from 2002. The industry added 48 gigawatts of net new capacity (in new generators) in 2003. This is the second largest amount of capacity added in any single year, behind only 2002 when 58 gigawatts were added. The recent trend in large natural gas-fired capacity additions continued in 2003. Eighty percent of the new unit capacity was natural gas-fired. An additional 16 percent of new capacity was dual-fired natural gas and petroleum units, most of which utilize natural gas as the primary energy source.

Although coal-fired capacity in 2003 maintained the largest share of U.S. electric generating capacity, coal continued its long-term decline, as the majority of recent capacity additions have been natural gas-fired (Figure ES 1). Additionally, re-powering of large coal-fired plants into more efficient natural gas combined cycle plants, as well as the retirement of older coal-fired units, has slightly reduced overall coal-fired capacity. End-of-year capacity totals show that natural gas and dual-fired capacity together account for 40 percent of the total generating capacity. Hydroelectric and nuclear each had a 10-percent share of the total, while "other renewables" accounted for 2 percent of the total.

Figure ES 1. U.S. Capacity by Fuel Type, 2003



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

The Blackout of August 14, 2003

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for four days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars).

On August 15, President George W. Bush and then-Prime Minister Jean Chrétien directed that a Joint U.S.-Canada Power System Outage Task Force be established to investigate the causes of the blackout. The Task Force concluded that this blackout could have been prevented and recommended 46 actions to be taken in both the United States and Canada to ensure that the electric system is more reliable. The full details of the final report can be found on the Internet at: https://reports.energy.gov/B-F-Web-Part1.pdf. The report is titled: U.S.-Canada Power System Outage Task Force. *"Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.*" Washington DC: USGPO, April 2004.

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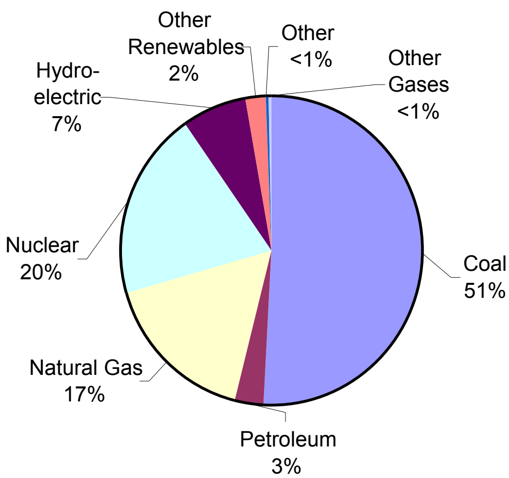
[1] Electric utilities include investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. In total, there are more than 3,100 electric utilities in the United States.
[2] Nonutilities include energy service providers, power marketers, IPPs, and CHPs.
[3] An IPP is an entity whose primary business is to produce electricity for use by the public.
[4] CHPs are plants designed to produce both heat and electricity from a single heat source.

Generation

In 2003, net generation of electricity rose slightly to 3,883 billion kilowatthours. This represents a 0.6 percent growth in electricity generation over the 2002 level; however, it is significantly below the average annual growth rate of 2.4 percent between 1992 and 2003, due mainly to a cooler summer season than the previous year. Regulated electric utilities' share of total generation continued to decline (63.4 percent in 2003 vs. 66.1 percent in 2002) as IPPs' share increased (27.4 percent vs. 24.8 percent in 2002). Figure ES 2 shows net generation by energy source.

Figure ES 2. U.S. Net Generation by Energy Source, 2003



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

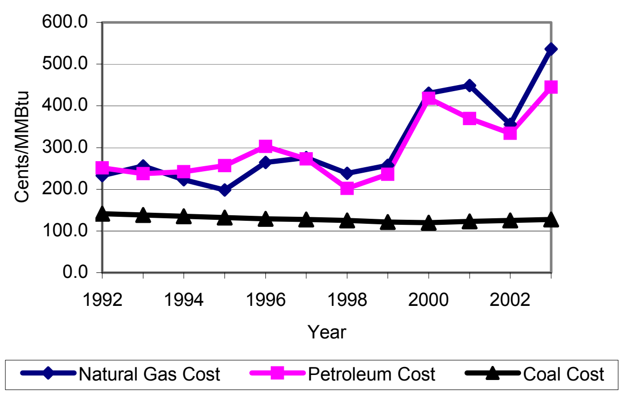
Fuel

The average cost for each of the three major fossil fuels used for electricity generation increased between 2002 and 2003. The average cost of natural gas to electricity generators increased from $3.56 per million Btu (MMBtu) in 2002 to a record level of $5.37 per MMBtu in 2003, exceeding the previous record of $4.49 per MMBtu set in 2001 (Figure ES 3). The cost of petroleum also increased, from a level of $3.34 per MMBtu in 2002 to $4.45 per MMBtu in 2003. While not at all-time record levels, the petroleum cost in 2003 was the highest since 1984. The cost of coal also increased for the year, from $1.26 per MMBtu in 2002 to $1.28 per MMBtu in 2003. On a percentage basis, the cost of natural gas increased by 50.7 percent from 2002 to 2003, while the cost of petroleum increased by 33.1 percent over the same period. Coal costs rose by only 1.6 percent from 2002 to 2003.

Emissions

The emissions estimates for electricity reflect fuel consumed for electric power generation and, in the case of combined heat and power plants, fuel consumed for the production of useful thermal output as well. Estimated carbon dioxide emissions by U.S. electric generators at 2,409 million metric tons, increased by 0.5 percent between 2002 and 2003, reaching the highest level since 2000. Emissions of nitrogen oxides at 4,396 thousand metric tons, declined by 8.5 percent over the same period, and have dropped 43 percent since 1992. Emissions of sulfur dioxide increased slightly between 2002 and 2003 (0.8 percent), but have dropped 30 percent since 1992.

Figure ES 3. Fuel Costs for Electricity Generation, 1992 – 2003



Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

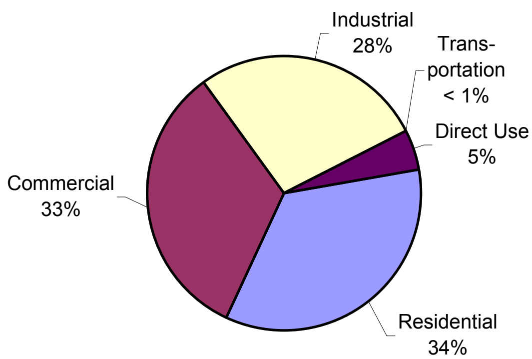
Trade

In 2003, wholesale purchases of electricity within the electric power industry were virtually flat at 2,669 billion kilowatthours. Sales for resale, however, grew by over 7 percent from the 2002 level to 2,972 billion kilowatthours. Imports fell by over 6 billion kilowatthours from last year to bottom at 30.4 billion kilowatthours, the lowest level in a decade. However, 2003 exports continued to grow, reaching 24 billion kilowatthours, which also represented a 10-year high.

Revenue and Expense Statistics

In 2003, total electric utility operating revenues (sales to ultimate customers, sales for resale, and other electric income) were nearly $314 billion, a 3.2 percent increase ($9.8 billion) compared to 2002. Major investor-owned utilities received over 72 percent of these revenues. Expenses for all classes of electric utilities increased to $273.7 billion, in contrast to the prior year ($261.3 billion) where investor-owned and some classes of public utilities had declining expenses.

Figure ES 4. U.S. End-user Sales with Direct Use, 2003



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

Retail Customers, Sales, and Revenues

Total retail sales in 2003 were 3,488 billion kilowatthours, up 0.8 percent from the 2002 level of 3,463 billion kilowatthours (Figure ES 4).

Sales to the residential sector were 1,273 billion kilowatthours, an increase from 2002 of 0.5 percent. Sales to the transportation sector in 2003 were reported separately for the first time. Those sales were previously included as part of "Other." With the reassignment of most volumes previously classified as "Other," the commercial sector shows an apparently large increase to 1,200 billion kilowatthours. However, almost all of this increase is attributable to the reclassified volumes from the "Other" sector. The industrial sector received a small portion of the "Other" volumes, resulting in sales of 1,008 billion kilowatthours. For sales excluding Direct Use, the residential sector accounted for 36 percent of the total volume in 2003, the commercial sector for 34 percent, and the industrial sector for 29 percent. The newly-reported transportation sector, which includes electricity delivered to and consumed by local, regional and metropolitan mass transportation systems, accounted for sales of 7 billion kilowatthours, or 0.2 percent of the national total.

While sales increased only slightly, revenue increased to nearly $259 billion in 2003, an increase of 3.7 percent from 2002. All customer classes experienced higher costs, with the national average retail price across all sectors averaging 7.42 cents per kilowatthour, an increase of 2.9 percent. Average retail price in the residential sector increased by 2.8 percent, in the commercial sector by 1.5 percent, and in the industrial sector by 5.1 percent. The average retail price in the transportation sector was 7.58 cents per kilowatthour.

Demand-Side Management

In 2003, electricity providers reported total peak-load reductions of 22,904 megawatts resulting from demand-side management (DSM), a negligible decrease from that reported in 2002. Reported DSM costs declined significantly to $1.3 billion, a 20 percent decrease from costs reported in 2002. DSM costs can vary significantly from year to year because of business cycle fluctuations and regulatory changes. Since costs are reported as they occur while program effects may appear in future years, DSM costs and effects may not vary directly by year. Nonetheless, nominal DSM expenditures have declined by half over the last 10 years.

Table ES. Summary Statistics for the United States, 1992 through 2003

Description	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Net Generation (thousand megawatthours)												
Coal[1]	1,973,737	1,933,130	1,903,956	1,966,265	1,881,087	1,873,516	1,845,016	1,795,196	1,709,426	1,690,694	1,690,070	1,621,206
Petroleum[2]	119,406	94,567	124,880	111,221	118,061	128,800	92,555	81,411	74,554	105,901	112,788	100,154
Natural Gas	649,908	691,006	639,129	601,038	556,396	531,257	479,399	455,056	496,058	460,219	414,927	404,074
Other Gases[3]	15,600	11,463	9,039	13,955	14,126	13,492	13,351	14,356	13,870	13,319	12,956	13,270
Nuclear	763,733	780,064	768,826	753,893	728,254	673,702	628,644	674,729	673,402	640,440	610,291	618,776
Hydroelectric Conventional[4]	275,806	264,329	216,961	275,573	319,536	323,336	356,453	347,162	310,833	260,126	280,494	253,088
Other Renewables[5]	87,410	86,922	77,985	80,906	79,423	77,088	77,183	75,796	73,965	76,535	76,213	73,770
Pumped Storage[6]	-8,535	-8,743	-8,823	-5,539	-6,097	-4,467	-4,040	-3,088	-2,725	-3,378	-4,036	-4,177
Other[7]	6,121	5,714	4,690	4,794	4,024	3,571	3,612	3,571	4,104	3,667	3,487	3,720
All Energy Sources	**3,883,185**	**3,858,452**	**3,736,644**	**3,802,105**	**3,694,810**	**3,620,295**	**3,492,172**	**3,444,188**	**3,353,487**	**3,247,522**	**3,197,191**	**3,083,882**
Net Summer Generating Capacity (megawatts)												
Coal[1]	313,019	315,350	314,230	315,114	315,496	315,786	313,624	313,382	311,386	311,415	310,148	309,372
Petroleum[2] Only	36,429	38,213	39,714	35,890	35,587	40,399	43,202	43,585	43,708	42,695	44,019	45,642
Natural Gas Only	208,447	171,661	125,798	95,705	73,562	75,772	76,348	74,498	75,438	70,685	65,523	60,736
Dual Fired	171,295	162,289	153,482	149,833	146,039	130,399	129,384	128,570	121,958	123,110	120,157	118,913
Other Gases[3]	1,994	2,008	1,670	2,342	1,909	1,520	1,525	1,664	1,661	2,093	1,931	2,069
Nuclear	99,209	98,657	98,159	97,860	97,411	97,070	99,716	100,784	99,515	99,148	99,041	98,985
Hydroelectric/ Pumped Storage	99,216	99,727	98,580	98,881	98,958	98,669	98,725	97,548	99,948	99,249	98,557	95,962
Other Renewables[5]	18,199	16,755	16,180	15,572	15,942	15,444	15,351	15,309	15,300	15,021	14,656	14,281
Other[7]	638	641	440	523	1,023	810	774	550	550	550	550	545
All Energy Sources	**948,446**	**905,301**	**848,254**	**811,719**	**785,927**	**775,868**	**778,649**	**775,890**	**769,463**	**763,967**	**754,582**	**746,507**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	696,752	696,376	674,833	680,941	653,857	638,086	618,389	602,438	589,860	578,640	565,041	554,462
Capacity Resources (megawatts)	856,131	833,380	788,990	808,054	765,744	744,670	737,855	730,376	727,481	711,583	705,360	697,432
Capacity Margins (percent)	18.6	16.4	14.5	15.7	14.6	14.3	16.2	17.5	18.9	18.7	19.9	20.5
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	1,014,058	987,583	972,691	994,933	949,802	946,295	931,949	907,209	860,594	848,796	842,153	805,140
Petroleum (thousand barrels)[2]	206,653	168,597	216,672	195,228	207,871	222,640	159,715	144,626	132,578	183,618	192,462	172,241
Natural Gas (millions of cubic feet)	5,616,135	6,126,062	5,832,305	5,691,481	5,321,984	5,081,384	4,564,770	4,312,458	4,737,871	4,367,148	3,928,653	3,899,718
Other Gases (millions of btu)[3]	156,306	131,230	97,308	125,971	126,387	124,988	119,412	158,560	132,520	136,381	136,230	141,279
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	17,720	17,561	18,944	20,466	20,373	20,320	21,005	20,806	20,418	20,609	19,750	19,372
Petroleum (thousand barrels)[2]	17,939	14,811	18,268	22,266	26,822	28,845	28,802	27,873	25,562	27,929	26,394	24,077
Natural Gas (millions of cubic feet)	721,267	860,019	898,286	985,263	982,958	949,106	868,569	865,774	834,382	784,015	733,584	717,860
Other Gases (millions of btu)[3]	137,838	146,882	166,161	230,082	223,713	208,828	187,680	187,290	180,895	179,595	177,554	199,858
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	1,031,778	1,005,144	991,635	1,015,398	970,175	966,615	952,955	928,015	881,012	869,405	861,904	824,512
Petroleum (thousand barrels)[2]	224,593	183,408	234,940	217,494	234,694	251,486	188,517	172,499	158,140	211,547	218,855	196,318
Natural Gas (millions of cubic feet)	6,337,402	6,986,081	6,730,591	6,676,744	6,304,942	6,030,490	5,433,338	5,178,232	5,572,253	5,151,163	4,662,236	4,617,578
Other Gases (millions of btu)[3]	294,143	278,111	263,469	356,053	350,100	333,816	307,092	345,850	313,415	315,976	313,784	341,137
Stocks at Electricity Generators (year end)												
Coal (thousand tons)[8]	121,567	141,714	138,496	102,296	141,604	120,501	98,826	114,623	126,304	126,897	111,341	154,130
Petroleum (thousand barrels)[2]	53,170	52,490	57,031	40,932	54,109	56,591	51,138	48,146	50,821	63,333	62,890	72,183
Receipts of Fuel at Electricity Generators[9]												
Coal (thousand tons)[1]	1,026,281	884,287	762,815	790,274	908,232	929,448	880,588	862,701	826,860	831,929	769,152	775,963
Petroleum (thousand barrels)[2]	205,283	120,851	124,618	108,272	145,939	181,276	128,749	113,678	89,908	149,258	154,144	147,825
Natural Gas (millions of cubic feet)[10]	5,479,821	5,607,737	2,148,924[R]	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
Cost of Fuel at Electricity Generators (cents per million Btu)[9]												
Coal[1]	127.5	125.5	123.2	120.0	121.6	125.2	127.3	128.9	131.8	135.5	138.5	141.2
Petroleum[2]	445.1	334.3	369.3	417.9	235.9	202.1	273.0	302.6	256.6	242.3	237.3	251.4
Natural Gas[10]	536.6	356.0	448.7	430.2	257.4	238.1	276.0	264.1	198.4	223.0	256.0	232.8
Emissions (thousand metric tons)												
Carbon Dioxide (CO_2)	2,408,961	2,397,937[R]	2,379,603[R]	2,429,394[R]	2,326,558[R]	2,313,013[R]	2,223,347[R]	2,155,453[R]	2,079,761[R]	2,063,788[R]	2,034,206[R]	1,951,425[R]
Sulfur Dioxide (SO_2)	10,594	10,515[R]	10,966[R]	11,297[R]	12,445[R]	12,509[R]	13,524[R]	12,908[R]	11,898[R]	14,473[R]	14,968[R]	15,031[R]
Nitrogen Oxides (NO_X)	4,396	4,802[R]	5,045[R]	5,380[R]	5,732[R]	6,235[R]	6,324[R]	6,281[R]	7,885[R]	7,802[R]	7,997[R]	7,728[R]
Trade (million megawatthours)[11]												
Purchases[12]	2,669	2,664	3,074	2,346	2,040	2,021	1,966	1,798	1,618	1,528	1,492	1,396
Sales for Resale[12]	2,972	2,766	2,900[R]	2,358[R]	1,988[R]	1,922[R]	1,839	1,656	1,495	1,388	1,387	1,284
Electricity Imports and Exports (thousand megawatthours)												
Imports	30,390	36,373[R]	38,500	48,592	43,215	39,513	43,031	43,497	42,854	46,833	31,358	28,247
Exports	23,972	13,560[R]	16,473	14,829	14,222	13,656	8,974	3,302	3,623	2,010	3,541	2,827
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	117,092	116,448	114,318	111,718	110,383	109,048	107,066	105,343	103,917	102,321	100,860	99,513
Commercial[13]	16,636	15,277	14,940	14,349	14,074	13,887	13,542	13,181	12,949	12,733	12,526	12,367
Industrial	720	595	574	527	553	540	563	586	581	584	553	548
Transportation[14]	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	1,042	1,008	974	935	933	952	894	882	851	795	858
All Sectors	134,450	133,363	130,840	127,568	125,945	124,408	122,123	120,004	118,330	116,489	114,735	113,286

See end of table for Notes and Sources.

Table ES. Summary Statistics for the United States, 1992 through 2003 (Continued)

Description	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Retail Sales and Revenue Data – Bundled and Unbundled (Continued)												
Sales to Ultimate Customers (thousand megawatthours)												
Residential	1,273,486	1,266,959	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
Commercial[13]	1,199,718	1,116,248	1,089,154	1,055,232	1,001,996	979,401	928,633	887,445	862,685	820,269	794,573	761,271
Industrial	1,007,988	972,168	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
Transportation[14]	6,999	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	107,146	113,756	109,496	106,952	103,518	102,901	97,539	95,407	97,830	94,944	93,442
All Sectors	3,488,192	3,462,521	3,369,781	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
Direct Use[15]	168,295	166,184	162,649	170,943	171,629	160,866	156,239	152,638	150,677	146,325	139,238	133,841
Total Disposition	3,656,487	3,628,705	3,532,429	3,592,357	3,483,716	3,425,097	3,301,849	3,253,765	3,163,963	3,080,888	3,000,700	2,897,207
Revenue From Ultimate Customers (million dollars)												
Residential	110,779	107,229	103,671	98,209	93,483	93,360	90,704	90,503	87,610	84,552	82,814	76,848
Commercial[13]	95,772	87,706	86,354	78,405	72,771	72,575	70,497	67,829	66,365	63,396	61,521	58,343
Industrial	51,716	47,485	48,573	49,369	46,846	47,050	47,023	47,536	47,175	48,069	47,357	46,993
Transportation[14]	531	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	7,208	7,999	7,179	6,796	6,863	7,110	6,741	6,567	6,689	6,528	6,296
All Sectors	258,798	249,629	246,597	233,163	219,896	219,848	215,334	212,609	207,717	202,706	198,220	188,480
Average Retail Price (cents per kilowatthour)												
Residential	8.70	8.46	8.62	8.24	8.16	8.26	8.43	8.36	8.40	8.38	8.32	8.21
Commercial[13]	7.98	7.86	7.93	7.43	7.26	7.41	7.59	7.64	7.69	7.73	7.74	7.66
Industrial	5.13	4.88	5.04	4.64	4.43	4.48	4.53	4.60	4.66	4.77	4.85	4.83
Transportation[14]	7.58	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	6.73	7.03	6.56	6.35	6.63	6.91	6.91	6.88	6.84	6.88	6.74
All Sectors	7.42	7.21	7.32	6.81	6.64	6.74	6.85	6.86	6.89	6.91	6.93	6.82
Revenue and Expense Statistics (million dollars)[16]												
Major Investor Owned												
Utility Operating Revenues	226,227	219,389	267,525	235,336	214,160	218,175	215,083	207,459	199,967	196,282	193,638	185,493
Utility Operating Expenses	197,459	188,745	235,198	210,324	182,258	186,498	182,796	173,920	165,321	164,207	161,908	153,682
Net Utility Operating Income	28,768	30,644	32,327	25,012	31,902	31,677	32,286	33,539	34,646	32,074	31,730	31,811
Major Publicly Owned (with Generation Facilities)[17]												
Operating Revenues	33,906	32,776	38,028	31,843	26,767	26,155	25,397	24,207	23,473	23,267	22,522	21,686
Operating Expenses	29,637	28,638	32,789	26,244	21,274	20,880	20,425	19,084	18,959	18,649	18,162	17,191
Net Electric Operating Income	4,268	4,138	5,238	5,598	5,493	5,275	4,972	5,123	4,514	4,618	4,360	4,496
Major Publicly Owned (without Generation Facilities)[17]												
Operating Revenues	12,454	11,546	10,417	9,904	9,354	8,790	8,586	8,582	8,435	7,996	7,523	7,247
Operating Expenses	11,481	10,703	9,820	9,355	8,737	8,245	8,033	8,123	7,979	7,567	7,063	6,844
Net Electric Operating Income	974	843	597	549	617	545	552	459	457	429	460	404
Major Federally Owned												
Operating Revenues	11,798	11,470	12,458	10,685	10,186	9,780	8,833	9,082	8,743	8,552	8,141	7,872
Operating Expenses	8,763	8,665	10,013	8,139	7,775	7,099	5,999	6,390	6,162	6,303	6,056	5,883
Net Electric Operating Income	3,035	2,805	2,445	2,546	2,411	2,681	2,834	2,692	2,581	2,249	2,085	1,989
Major Cooperative Borrower Owned												
Operating Revenues	29,228	27,458[R]	26,458	25,629	23,824	23,988	23,321	24,424	24,609	23,777	24,873	23,325
Operating Expenses	26,361	24,561[R]	23,763	22,982	21,283	21,223	20,715	23,149	21,741	20,993	21,675	20,353
Net Electric Operating Income	2,867	2,897[R]	2,696	2,647	2,541	2,764	2,606	2,872	2,868	2,784	3,197	2,973
Demand-Side Management (DSM) Data												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction[18]	22,904	22,936	24,955	22,901	26,455	27,231	25,284	29,893	29,561	25,001	23,069	17,204
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119	31,779
Load Management	2,020	1,790	1,816	875	872	392	953	1,989	2,093	2,763	4,175	4,114
DSM Cost (million dollars)												
Total Cost[19]	1,297	1,626	1,630	1,565	1,424	1,421	1,636	1,902	2,421	2,716	2,744	2,348

[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 excluding hydroelectric pumped storage facility production.

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

[6] The quantity of output from a hydroelectric pumped storage facility is where net value equals production minus energy used for pumping.

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

[8] Anthracite, bituminous coal, subbituminous coal, and lignite; excludes waste coal.

[9] Receipts data for regulated utilities are compiled by EIA from data collected by the Federal Energy Regulatory Commission (FERC) on the FERC Form 423. These data are collected by FERC for regulatory rather than statistical and publication purposes. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. However, EIA does not attempt to resolve any late filing issues in the FERC Form 423 data. For 2003 only, estimates were developed for missing or incomplete data from some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 data cannot be directly compared to previous years' data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes. Beginning in 2002, includes data from the Form EIA-423 for independent power producers and combined heat and power producers.

[10] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.

[11] Alaska and Hawaii are not included.

[12] The data collection instrument was changed for 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001 and after 2001 should be done with caution.

[13] Includes miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, and interdepartmental sales formerly reported as "Other."

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

[15] Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales among adjacent or co-located facilities for which revenue information is not available.

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

[17] The 1998-2003 data represent those utilities meeting a threshold of 150 million kilowatthours of sales to ultimate customers and/or 150 million kilowatthours of sales for resale for the two previous years. The 1992-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of sales to ultimate customers and/or 120 million kilowatthours of sales for resale for the two previous years.

[18] Actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability.

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

NA = Not available.

R = Revised.

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

Sources: Form EIA-411, "Coordinated Bulk Power Supply Program Report;" Form EIA-412, "Annual Electric Industry Financial Report;" Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Form EIA-767, "Steam-Electric Plant Operation and Design Report;" Form EIA-860, " Annual Electric Generator Report;" Form EIA-861, "Annual Electric Power Industry Report;" 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 Report of Cost and Quality of Fuels for Electric Plants," and predecessor forms; Rural Utility Services (RUS) Form 7, "Operating Report;" RUS Form 12, "Operating Report;" Imports and Exports: Mexico data - DOE, Fossil Fuels, Office of Fuels Programs, Form FE-781R, "Annual Report of International Electrical Export/Import Data:" Canada data - National Energy Board of Canada (metered energy fIrm and interruptible).

Chapter 1. Generation and Useful Thermal Output

Table 1.1. Net Generation by Energy Source by Type of Producer, 1992 through 2003
(Thousand Megawatthours)

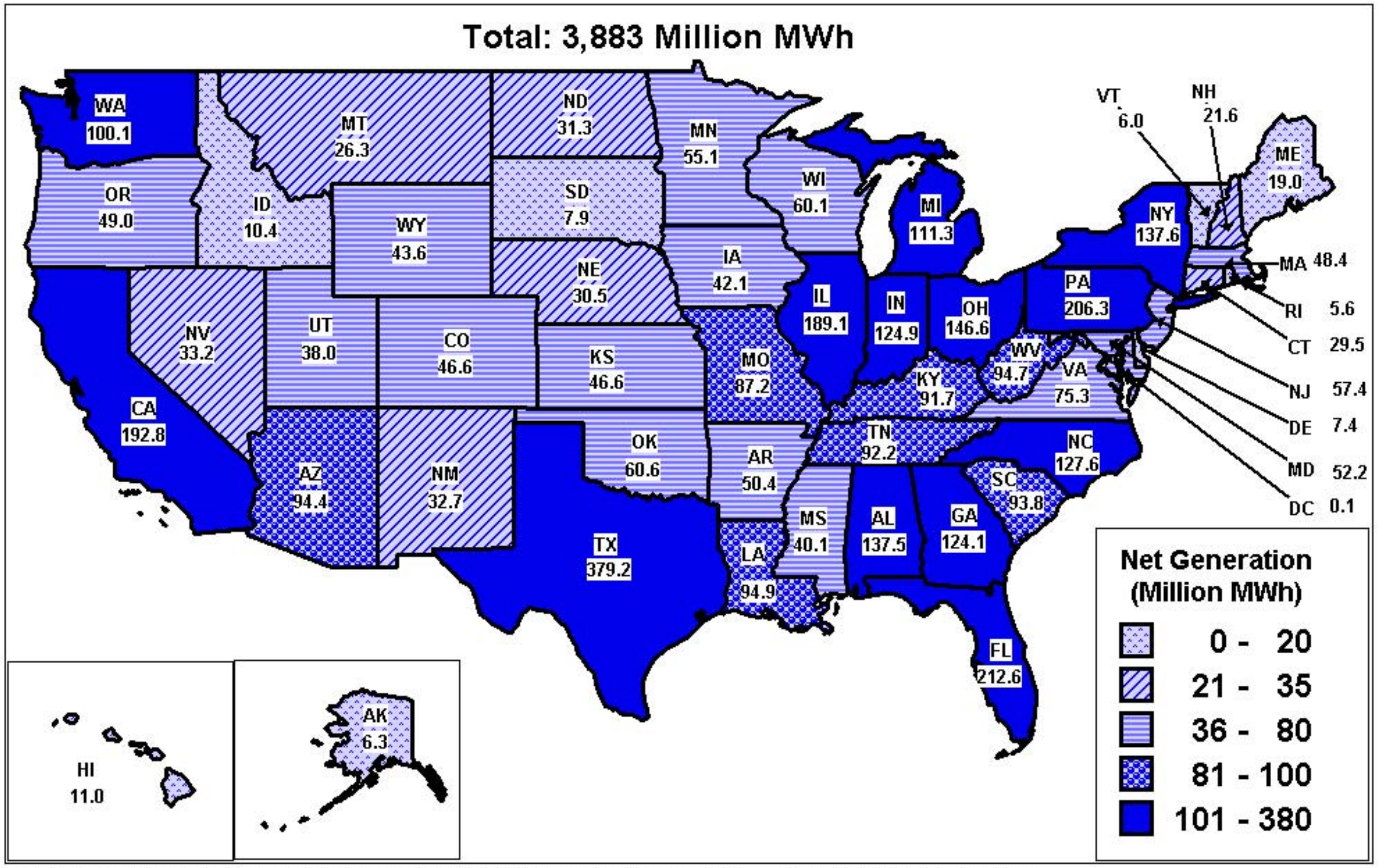
Period	Coal[1]	Petroleum [2]	Natural Gas	Other Gases[3]	Nuclear	Hydroelectric Conventional[4]	Other Renewables[5]	Hydroelectric Pumped Storage	Other[6]	Total
Total (All Sectors)										
1992	1,621,206	100,154	404,074	13,270	618,776	253,088	73,770	-4,177	3,720	3,083,882
1993	1,690,070	112,788	414,927	12,956	610,291	280,494	76,213	-4,036	3,487	3,197,191
1994	1,690,694	105,901	460,219	13,319	640,440	260,126	76,535	-3,378	3,667	3,247,522
1995	1,709,426	74,554	496,058	13,870	673,402	310,833	73,965	-2,725	4,104	3,353,487
1996	1,795,196	81,411	455,056	14,356	674,729	347,162	75,796	-3,088	3,571	3,444,188
1997	1,845,016	92,555	479,399	13,351	628,644	356,453	77,183	-4,040	3,612	3,492,172
1998	1,873,516	128,800	531,257	13,492	673,702	323,336	77,088	-4,467	3,571	3,620,295
1999	1,881,087	118,061	556,396	14,126	728,254	319,536	79,423	-6,097	4,024	3,694,810
2000	1,966,265	111,221	601,038	13,955	753,893	275,573	80,906	-5,539	4,794	3,802,105
2001	1,903,956	124,880	639,129	9,039	768,826	216,961	77,985	-8,823	4,690	3,736,644
2002	1,933,130	94,567	691,006	11,463	780,064	264,329	86,922	-8,743	5,714	3,858,452
2003	1,973,737	119,406	649,908	15,600	763,733	275,806	87,410	-8,535	6,121	3,883,185
Electricity Generators, Electric Utilities										
1992	1,575,895	88,916	263,872	--	618,776	243,736	10,200	-4,177	--	2,797,219
1993	1,639,151	99,539	258,915	--	610,291	269,098	9,565	-4,036	--	2,882,525
1994	1,635,493	91,039	291,115	--	640,440	247,071	8,933	-3,378	--	2,910,712
1995	1,652,914	60,844	307,306	--	673,402	296,378	6,409	-2,725	--	2,994,529
1996	1,737,453	67,346	262,730	--	674,729	331,058	7,214	-3,088	--	3,077,442
1997	1,787,806	77,753	283,625	--	628,644	341,273	7,462	-4,040	--	3,122,523
1998	1,807,480	110,158	309,222	--	673,702	308,844	7,206	-4,441	--	3,212,171
1999	1,767,679	86,929	296,381	--	725,036	299,914	3,716	-5,982	--	3,173,674
2000	1,696,619	72,180	290,715	--	705,433	253,155	2,241	-4,960	--	3,015,383
2001	1,560,146	78,908	264,434	--	534,207	197,804	2,152	-7,704	--	2,629,946
2002	1,514,670	59,125	229,639	206	507,380	242,302	3,569	-7,434	--	2,549,457
2003	1,500,281	69,930	186,967	243	458,829	249,622	3,941	-7,532	--	2,462,281
Electricity Generators, Independent Power Producers										
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	--	9,023	34,703	-26	--	91,455
1999	64,387	17,906	60,264	36	3,218	14,749	40,460	-115	--	200,905
2000	213,956	25,795	108,712	181	48,460	18,183	42,831	-579	--	457,540
2001	291,678	34,257	162,540	10	234,619	15,945	42,661	-1,119	--	780,592
2002	366,535	24,150	227,155	29	272,684	18,189	46,456	-1,309	1,441	955,331
2003	415,498	38,571	234,240	13	304,904	21,890	47,753	-1,003	1,339	1,063,205
Combined Heat and Power, Electric Power[7]										
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	31,003	5,984	127,966	576	--	--	3,988	--	--[R]	169,515
2002	29,408	6,458	150,889	1,734	--	--	4,565	--	615	193,670
2003	36,935	5,195	146,097	2,392	--	--	4,822	--	233	195,674
Combined Heat and Power, Commercial[8]										
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	995	438	4,434	*	--	66	1,482	--	*	7,416
2002	992	431	4,310	*	--	13	1,585	--	84	7,415
2003	1,206	423	3,899	--	--	72	1,894	--	2	7,496
Combined Heat and Power, Industrial[9]										
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	20,135	5,293	79,755	8,454	--	3,145	27,703	--	4,690	149,175
2002	21,525	4,403	79,013	9,493	--	3,825	30,747	--	3,574	152,580
2003	19,817	5,285	78,705	12,953	--	4,222	29,001	--	4,546	154,530

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Conventional hydroelectric power excluding pumped storage facilities.
[5] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy and wind.
[6] 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.

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

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

Figure 1.1. U.S. Electric Power Industry Net Generation by State, 2003 (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, 1992 through 2003
(Billion Btus)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Other Renewables[4]	Other[5]	Total
Total Combined Heat and Power							
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	354,204	90,308	740,979	132,937	597,475	42,248	1,958,151
2002	336,848	72,826	708,738	117,513	584,976	34,796	1,855,697
2003	333,361	85,263	610,122	110,263	646,223	41,103	1,826,335
Combined Heat and Power, Electric Power							
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	51,515	6,087	164,206	4,681	16,019	0	242,508
2002	40,020	3,869	214,137	5,961	17,219	63	281,269
2003	38,249	7,379	200,077	9,282	22,760	321	278,068
Combined Heat and Power, Commercial							
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	*	18,057	--	73,474
1997	21,958	3,832	39,893	20	20,232	--	85,935
1998	20,185	4,853	38,510	34	18,426	--	82,008
1999	20,479	3,298	36,857	*	17,145	--	77,779
2000	21,001	3,827	39,293	*	17,613	--	81,734
2001	18,495	4,118	34,923	--	14,024	--	71,560
2002	18,477	2,743	36,265	*	11,703	--	69,188
2003	22,780	2,716	16,955	--	14,438	--	56,889
Combined Heat and Power, Industrial							
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	284,194	80,103	541,850	128,256	567,432	42,248	1,644,083
2002	278,351	66,214	458,336	111,552	556,054	34,733	1,505,240
2003	272,332	75,168	393,090	100,981	609,025	40,782	1,491,378

[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)
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy and wind.
[5] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

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

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

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

Chapter 2. Capacity

Table 2.1. Existing Net Summer Capacity by Energy Source and Producer Type, 1992 through 2003
(Megawatts)

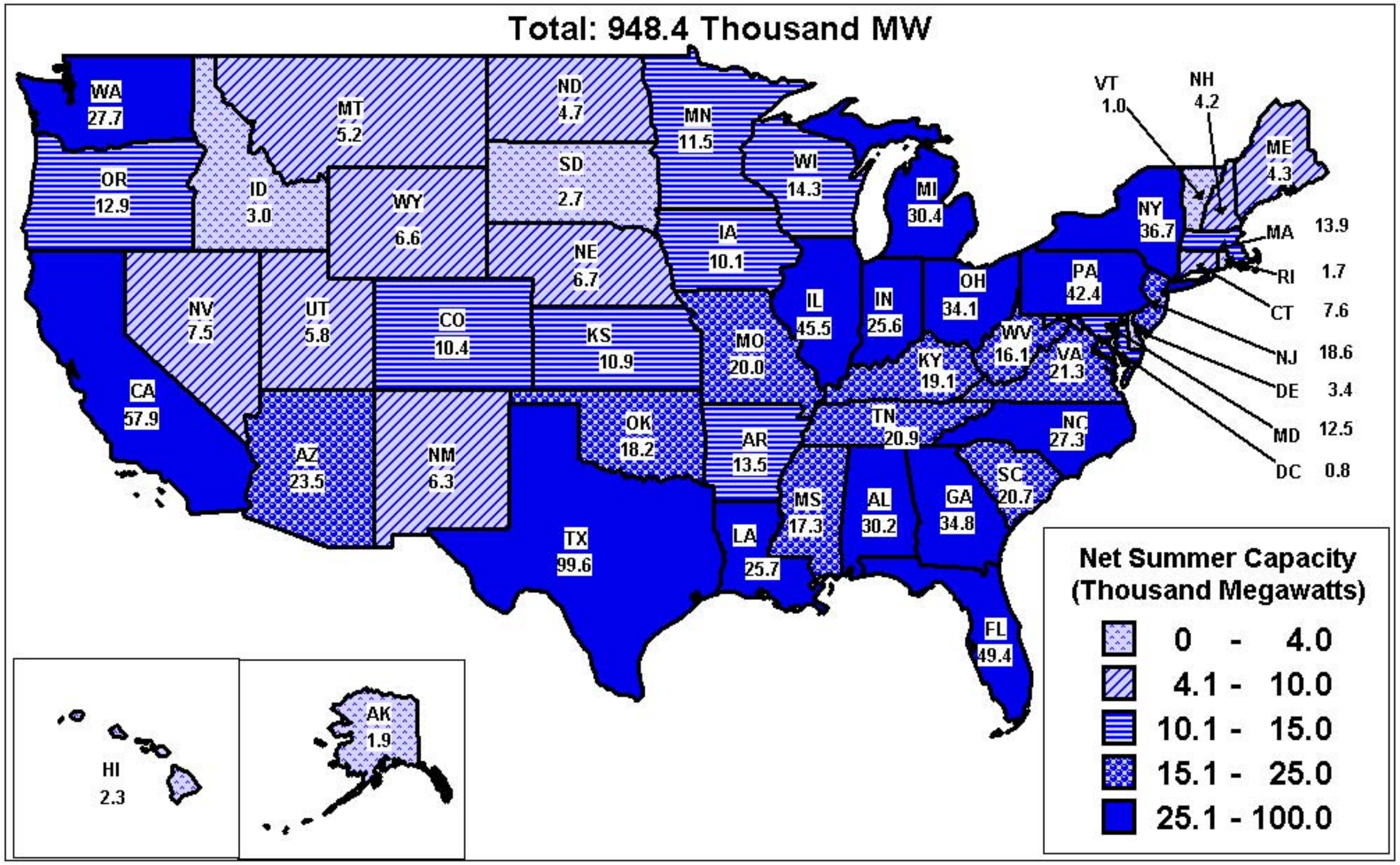
Period	Coal[1]	Petroleum[2]	Natural Gas	Dual Fired	Other Gases[3]	Nuclear	Hydro-electric[4]	Other Renewables[5]	Other[6]	Total
Total (All Sectors)										
1992	309,372	45,642	60,736	118,913	2,069	98,985	95,962	14,281	545	746,507
1993	310,148	44,019	65,523	120,157	1,931	99,041	98,557	14,656	550	754,582
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
2002	315,350	38,213	171,661	162,289	2,008	98,657	99,727	16,755	641	905,301
2003	313,019	36,429	208,447	171,295	1,994	99,209	99,216	18,199	638	948,446
Electricity Generators, Electric Utilities										
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
2002	244,056	23,067	50,026	88,476	61	63,202	91,198	989	--	561,074
2003	236,473	20,766	48,233	89,183	61	60,964	90,630	925	13	547,249
Electricity Generators, Independent Power Producers										
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	60,701	13,911	57,933	56,161	--	35,099	7,444	9,680	--	240,929
2002	61,770	13,439	85,464	64,054	12	35,455	7,475	10,435	35	278,138
2003	66,538	14,412	118,694	71,546	6	38,244	7,777	11,832	--	329,049
Combined Heat and Power, Electric Power[7]										
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	4,628	371	18,027	3,799	287	--	9	791	28	27,940
2002	5,222	829	21,924	7,897	182	--	--	555	--	36,610
2003	5,534	313	26,938	8,695	185	--	1	665	--	42,332
Combined Heat and Power, Commercial[8]										
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
2002	292	264	507	746	--	--	22	357	--	2,188
2003	347	276	501	560	--	--	22	371	--	2,077
Combined Heat and Power, Industrial[9]										
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
2002	4,010	615	13,740	1,116	1,752	--	1,033	4,419	607	27,291
2003	4,127	662	14,081	1,310	1,742	--	786	4,406	625	27,740

[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 and hydroelectric pumped storage.
[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.

Notes: • See Glossary reference for definitions. • Reporting of electric utility and independent power producer capacity at the plant-generator level became available for 2003. Some capacity in 2001 and 2002 that is classified based on the operating company's classification as an electric utility or an independent power producer is classified in 2003 based on the individual plant generator's classification as an electric utility plant-generator or an independent power power producer plant-generator, regardless of the operating company's classification. • Totals may not equal sum of components because of independent rounding.

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

Figure 2.1 U.S. Electric Power Industry Existing Net Summer Capacity by State, 2003 (Thousand Megawatts)



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

Table 2.2. Existing Capacity by Energy Source, 2003
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Coal[1]	1,535	335,793	313,019	315,237
Petroleum[2]	3,121	40,965	36,429	40,023
Natural Gas	3,069	238,967	208,447	224,366
Dual Fired	3,056	190,739	171,295	183,033
Other Gases[3]	105	2,284	1,994	1,984
Nuclear	104	105,415	99,209	100,893
Hydroelectric[4]	4,145	96,352	99,216	98,399
Other Renewables[5]	1,582	20,474	18,199	18,524
Other[6]	39	704	638	640
Total	**16,756**	**1,031,692**	**948,446**	**983,099**

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

Notes: • Where there is more than one energy source associated with a generator, the predominant energy source is reported here. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.3. Existing Capacity by Producer Type, 2003
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Electric Power Sector				
Electric Utilities	8,984	583,633	547,249	560,682
Independent Power Producers	4,411	365,176	329,049	345,629
Total	**13,395**	**948,809**	**876,297**	**906,310**
Combined Heat and Power Sector				
Electric Power[1]	711	49,079	42,332	45,423
Commercial	640	2,375	2,077	2,188
Industrial	2,010	31,429	27,740	29,177
Total	**3,361**	**82,883**	**72,149**	**76,789**
Total All Sectors	**16,756**	**1,031,692**	**948,446**	**983,099**

[1] Includes only independent power producers' combined heat and power facilities.
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.4. Planned Nameplate Capacity Additions from New Generators, by Energy Source, 2004 through 2008
(Megawatts)

Energy Source	2004	2005	2006	2007	2008
Coal[1]	155	991	2,376	4,814	1,390
Petroleum[2]	238	361	344	168	180
Natural Gas	22,490	28,404	23,850	20,985	6,797
Other Gases[3]	--	--	--	580	580
Nuclear	--	--	--	--	--
Hydroelectric[4]	8	11	11	42	4
Other Renewables[5]	257	240	57	36	133
Other[6]	--	--	--	--	--
Total	**23,149**	**30,007**	**26,638**	**26,624**	**9,083**

[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 and hydroelectric pumped storage.
[5] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[6] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Notes: • Where there is more than one energy source associated with a generator, the predominant energy source is reported here. These data reflect plans as of January 1, 2004. Delays and cancellations may have occurred subsequently to the data reporting. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.5. Planned Capacity Additions from New Generators, by Energy Source, 2004-2008
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
		2004		
U.S. Total	**236**	**23,149**	**19,848**	**21,828**
Coal[1]	2	155	156	157
Petroleum[2]	61	238	215	231
Natural Gas	152	22,490	19,215	21,177
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric[4]	6	8	8	8
Other Renewables[5]	15	257	253	255
Other[6]	--	--	--	--
		2005		
U.S. Total	**223**	**30,007**	**25,924**	**28,411**
Coal[1]	5	991	922	932
Petroleum[2]	25	361	323	348
Natural Gas	161	28,404	24,450	26,900
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric[4]	7	11	10	10
Other Renewables[5]	25	240	219	221
Other[6]	--	--	--	--
		2006		
U.S. Total	**138**	**26,638**	**23,044**	**25,241**
Coal[1]	4	2,376	2,271	2,276
Petroleum[2]	4	344	296	324
Natural Gas	123	23,850	20,428	22,591
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric[4]	2	11	10	10
Other Renewables[5]	5	57	40	40
Other[6]	--	--	--	--
		2007		
U.S. Total	**128**	**26,624**	**23,306**	**25,352**
Coal[1]	10	4,814	4,485	4,525
Petroleum[2]	4	168	142	164
Natural Gas	108	20,985	18,113	20,023
Other Gases[3]	2	580	493	568
Nuclear	--	--	--	--
Hydroelectric[4]	2	42	40	39
Other Renewables[5]	2	36	34	34
Other[7]	--	--	--	--
		2008		
U.S. Total	**39**	**9,083**	**7,964**	**8,627**
Coal[1]	3	1,390	1,296	1,307
Petroleum[2]	1	180	153	176
Natural Gas	29	6,797	5,895	6,473
Other Gases[3]	2	580	500	550
Nuclear	--	--	--	--
Hydroelectric[4]	1	4	4	4
Other Renewables[5]	3	133	116	117
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 and hydroelectric pumped storage.
[5] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[6] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Notes: • Where there is more than one energy source associated with a generator, the predominant energy source is reported here. These data reflect plans as of January 1, 2004. Delays and cancellations may have occurred subsequently to the data reporting. • Totals may not equal sum of components because of independent rounding.

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

Table 2.6. Capacity Additions, Retirements and Changes by Energy Source, 2003
(Megawatts)

Energy Source	Generator Additions				Generator Retirements				Updates and Revisions[1]		
	Number of Gene-rators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Number of Gene-rators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Coal[2]	1	88	70	90	22	1,359	1,185	1,193	-1,136	-1,216	-1,170
Petroleum[3]	78	330	318	327	49	1,077	703	804	-1,494	-1,399	-1,891
Natural Gas	259	45,381	38,704	42,049	52	1,909	1,745	1,764	526	-172	-823
Dual Fired	84	8,803	7,588	8,276	21	1,172	1,097	1,121	2,935	2,515	2,901
Other Gases[4]	--	--	--	--	--	--	--	--	73	-14	13
Nuclear	--	--	--	--	--	--	--	--	482	552	1,263
Hydroelectric[5]	--	--	--	--	11	13	12	12	22	-499	-395
Other Renewables[6]	87	1,629	1,620	1,621	12	64	56	57	113	-120	12
Other[7]	--	--	--	--	--	--	--	--	-52	-3	-4
Total	**509**	**56,230**	**48,300**	**52,364**	**167**	**5,592**	**4,799**	**4,952**	**1,469**	**-356**	**-93**

[1] Generator re-ratings, re-powering, and revisions/corrections to previously reported 2003 data. There is not a direct correlation between these columns of data since this is a mixture of changes.
[2] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[3] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[4] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[5] Conventional hydroelectric and hydroelectric pumped storage.
[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.

Notes: • Where there is more than one energy source, the predominant energy source is reported here. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Chapter 3. Demand, Capacity Resources, and Capacity Margins

Table 3.1. Noncoincident Peak Load, Actual and Projected by North American Electric Reliability Council Region, 1999 through 2008
(Megawatts)

North American Electric Reliability Council Region	Actual 1999	Actual 2000	Actual 2001	Actual 2002	Actual 2003
Summer					
ECAR	99,239	92,033	100,235	102,996	98,487
ERCOT	55,529	57,606	55,201	56,248	59,996
FRCC	37,493	37,194	39,062	40,696	40,475
MAAC	51,645	49,477	54,015	55,569	53,566
MAIN	51,535	52,552	56,344	56,396	56,988
MAPP (U.S.)	31,903	28,605	28,321	29,119	28,831
NPCC (U.S.)	52,855	50,057	55,949	56,012	55,018
SERC	149,685	156,088	149,293	158,767	153,110
SPP	38,609	40,199	40,273	39,688	40,367
WECC (U.S.)	113,629	114,602	109,119	119,074	122,537
Contiguous U.S.	**682,122**	**678,413**	**687,812**	**714,565**	**709,375**
Winter					
ECAR	86,239	84,546	85,485	87,300	86,332
ERCOT	39,164	44,641	44,015	45,414	42,702
FRCC	40,178	38,606	40,922	45,635	36,841
MAAC	40,220	43,256	39,458	46,551	45,625
MAIN	39,081	41,943	40,529	42,412	41,719
MAPP (U.S.)	25,200	24,536	21,815	23,645	24,134
NPCC (U.S.)	45,227	43,852	42,670	46,009	48,079
SERC	128,563	139,146	135,182	141,882	137,972
SPP	27,963	30,576	29,614	30,187	28,450
WECC (U.S.)	99,080	97,324	96,622	95,951	102,020
Contiguous U.S.	**570,915**	**588,426**	**576,312**	**604,986**	**593,874**

North American Electric Reliability Council Region	Projected 2004	Projected 2005	Projected 2006	Projected 2007	Projected 2008
Summer					
ECAR	102,423	104,765	107,689	109,852	112,007
ERCOT	61,432	62,906	64,416	65,962	67,545
FRCC	42,705	43,753	44,826	45,896	46,897
MAAC	56,886	58,056	59,126	60,170	61,224
MAIN	57,868	58,667	59,717	60,469	61,325
MAPP (U.S.)	29,244	30,116	30,857	31,329	31,956
NPCC (U.S.)	57,535	58,624	59,336	60,038	60,720
SERC	157,961	161,634	165,151	168,830	172,099
SPP	40,089	40,813	41,076	41,585	42,429
WECC (U.S.)	122,870	125,687	128,864	131,882	134,861
Contiguous U.S.	**729,013**	**745,021**	**761,058**	**776,013**	**791,063**
Winter					
ECAR	87,972	89,268	91,131	93,128	95,558
ERCOT	43,556	44,427	45,316	46,222	47,146
FRCC	45,418	46,546	47,692	48,769	49,944
MAAC	45,471	46,215	46,955	47,690	48,420
MAIN	42,409	43,336	43,955	44,487	45,206
MAPP (U.S.)	24,628	25,035	25,419	25,742	26,178
NPCC (U.S.)	47,986	48,532	49,040	49,504	49,896
SERC	141,176	143,675	146,565	149,327	152,227
SPP	28,469	28,825	29,065	29,504	30,088
WECC (U.S.)	104,393	106,525	108,857	111,206	113,575
Contiguous U.S.	**611,478**	**622,384**	**633,995**	**645,579**	**658,238**

Notes: • Actual data are final. • Projected data are updated annually. • NERC Regional Council names may be found in the Glossary reference. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • The winter peak period begins on December 1 and extends through March 31 of the following year. For example, winter 2001 begins December 1, 2001, and extends through March 31, 2002. • Totals may not equal sum of components because of independent rounding.

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

Table 3.2. Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Summer, 1992 through 2003
(Megawatts)

Region and Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
ECAR												
Net Internal Demand..................	98,487	101,251	100,235	98,651	94,072	92,359	91,103	88,573	85,643	84,967	83,530	80,536
Capacity Resources....................	123,755	119,736	113,136	115,379	107,451	105,545	105,106	104,953	103,003	101,605	101,910	100,027
Capacity Margin (percent)..........	20.4	15.4	11.4	14.5	12.5	12.5	13.3	15.6	16.9	16.4	18.0	19.5
ERCOT												
Net Internal Demand..................	59,282	55,833	55,106	53,649	51,697	50,254	47,746	45,636	44,990	43,630	42,629	43,093
Capacity Resources....................	74,764	76,849	70,797	69,622	65,423	59,788	55,771	55,230	55,074	54,219	54,323	54,994
Capacity Margin (percent)..........	20.7	27.3	22.2	22.9	21.0	15.9	14.4	17.4	18.3	19.5	21.5	21.6
FRCC												
Net Internal Demand..................	40,387	37,951	38,932	35,666	34,832	34,562	32,874	31,868	31,649	30,537	29,435	28,898
Capacity Resources....................	46,806	43,342	42,290	43,083	40,645	39,708	39,613	38,237	38,282	37,577	36,225	34,565
Capacity Margin (percent)..........	13.7	12.4	7.9	17.2	14.3	13.0	17.0	16.7	17.3	18.7	18.7	16.4
MAAC												
Net Internal Demand..................	53,566	54,296	54,015	51,358	49,325	47,626	46,548	45,628	45,224	44,571	44,198	44,348
Capacity Resources....................	65,897	63,619	59,533	60,679	57,831	55,511	56,155	56,774	56,881	56,271	55,328	55,272
Capacity Margin (percent)..........	18.7	14.7	9.3	15.4	14.7	14.2	17.1	19.6	20.5	20.8	20.1	19.8
MAIN												
Net Internal Demand..................	53,617	53,267	53,032	51,845	47,165	45,570	45,194	44,470	43,229	42,611	42,001	41,304
Capacity Resources....................	67,410	67,025	65,950	64,170	55,984	52,722	52,160	52,880	52,112	50,963	50,333	49,104
Capacity Margin (percent)..........	20.5	20.5	19.6	19.2	15.8	13.6	13.4	15.9	17.0	16.4	16.6	15.9
MAPP (U.S.)												
Net Internal Demand..................	28,775	28,825	27,125	28,006	30,606	29,766	28,221	27,298	27,487	26,855	25,901	26,050
Capacity Resources....................	33,287	34,259	32,271	34,236	35,373	34,773	34,027	33,121	32,665	32,267	31,964	32,411
Capacity Margin (percent)..........	13.6	15.9	15.9	18.2	13.5	14.4	17.1	17.6	15.9	16.8	19.0	19.6
NPCC (U.S.)												
Net Internal Demand..................	53,936	55,164	55,888	54,270	53,450	51,760	50,240	48,950	48,290	47,465	46,380	46,007
Capacity Resources....................	70,902	66,208	63,760	63,376	63,077	60,439	60,729	58,592	62,368	61,906	62,049	61,960
Capacity Margin (percent)..........	23.9	16.7	12.3	14.4	15.3	14.4	17.3	16.5	22.6	23.3	25.3	25.7
SERC												
Net Internal Demand..................	148,380	154,459	144,399	151,527	142,726	138,146	134,968	109,270	105,785	101,885	99,287	97,448
Capacity Resources....................	177,231	172,485	171,530	169,760	160,575	158,360	155,016	126,196	127,562	120,044	117,375	115,635
Capacity Margin (percent)..........	16.3	10.5	15.8	10.7	11.1	12.8	12.9	13.4	17.1	15.1	15.4	15.7
SPP												
Net Internal Demand..................	39,428	38,298	38,807	39,056	37,807	36,402	37,009	59,017	57,951	56,395	55,067	52,183
Capacity Resources....................	45,802	47,233	45,530	46,109	43,111	42,554	43,591	69,344	69,354	69,198	67,922	67,472
Capacity Margin (percent)..........	13.9	18.9	14.8	15.3	12.3	14.5	15.1	14.9	16.4	18.5	18.9	22.7
WECC (U.S.)												
Net Internal Demand..................	120,894	117,032	107,294	116,913	112,177	111,641	104,486	101,728	99,612	99,724	96,613	94,595
Capacity Resources....................	150,277	142,624	124,193	141,640	136,274	135,270	135,687	135,049	130,180	127,533	127,931	125,992
Capacity Margin (percent)..........	19.6	17.9	13.6	17.5	17.7	17.5	23.0	24.7	23.5	21.8	24.5	24.9
Contiguous U.S.												
Net Internal Demand................	**696,752**	**696,376**	**674,833**	**680,941**	**653,857**	**638,086**	**618,389**	**602,438**	**589,860**	**578,640**	**565,041**	**554,462**
Capacity Resources..................	**856,131**	**833,380**	**788,990**	**808,054**	**765,744**	**744,670**	**737,855**	**730,376**	**727,481**	**711,583**	**705,360**	**697,432**
Capacity Margin (percent).......	**18.6**	**16.4**	**14.5**	**15.7**	**14.6**	**14.3**	**16.2**	**17.5**	**18.9**	**18.7**	**19.9**	**20.5**

Notes: • NERC Regional Council names may be found in the Glossary reference. • In 1998, several utilities realigned from SPP to SERC. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Table 3.3. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Summer, 2003 through 2008
(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand	Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Capacity Resources	Capacity Margin (percent)
	2003			2004		
ECAR	98,487	123,755	20.4	99,780	128,165	22.1
ERCOT	59,282	74,764	20.7	60,031	76,784	21.8
FRCC	40,387	46,806	13.7	39,883	48,297	17.4
MAAC	53,566	65,897	18.7	55,804	66,550	16.1
MAIN	53,617	67,410	20.5	54,605	67,780	19.4
MAPP (U.S.)	28,775	33,287	13.6	29,015	33,950	14.5
NPCC (U.S.)	53,936	70,902	23.9	56,394	70,052	19.5
SERC	148,380	177,231	16.3	152,180	180,414	15.6
SPP	39,428	45,802	13.9	39,097	46,271	15.5
WECC (U.S.)	120,894	150,277	19.6	120,419	157,286	23.4
Contiguous U.S.	**696,752**	**856,131**	**18.6**	**707,208**	**875,549**	**19.2**
	2005			2006		
ECAR	102,132	128,943	20.8	105,054	133,471	21.3
ERCOT	61,505	78,725	21.9	63,015	79,746	21.0
FRCC	40,926	50,341	18.7	42,030	50,568	16.9
MAAC	56,984	68,591	16.9	58,054	68,698	15.5
MAIN	55,494	69,817	20.5	56,540	71,454	20.9
MAPP (U.S.)	29,886	34,308	12.9	30,624	34,556	11.4
NPCC (U.S.)	57,483	72,780	21.0	58,185	75,737	23.2
SERC	156,079	181,734	14.1	159,801	184,660	13.5
SPP	39,812	45,808	13.1	40,066	46,049	13.0
WECC (U.S.)	123,221	161,393	23.7	126,391	169,078	25.2
Contiguous U.S.	**723,522**	**892,440**	**18.9**	**739,760**	**914,017**	**19.1**
	2007			2008		
ECAR	107,193	134,398	20.2	109,357	135,898	19.5
ERCOT	64,561	79,921	19.2	66,144	79,922	17.2
FRCC	43,100	51,395	16.1	44,110	52,916	16.6
MAAC	59,098	68,698	14.0	60,152	68,698	12.4
MAIN	57,283	73,506	22.1	58,136	74,252	21.7
MAPP (U.S.)	31,095	35,409	12.2	31,722	35,682	11.1
NPCC (U.S.)	58,887	79,970	26.4	59,559	80,400	25.9
SERC	163,667	186,743	12.4	166,961	188,404	11.4
SPP	40,571	46,126	12.0	41,407	45,755	9.5
WECC (U.S.)	129,408	173,316	25.3	132,385	174,154	24.0
Contiguous U.S.	**754,863**	**929,482**	**18.8**	**769,933**	**936,081**	**17.7**

Notes: • Actual data are final. • Projected data are updated annually. • NERC Regional Council names may be found in the Glossary reference. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • 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, 2003 through 2008
(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand	Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Capacity Resources	Capacity Margin (percent)
	2003/ 2004			2004/ 2005		
ECAR	86,332	129,351	33.3	85,812	133,357	35.7
ERCOT	41,988	77,111	45.5	42,163	80,021	47.3
FRCC	36,229	50,010	27.6	41,805	51,049	18.1
MAAC	45,625	68,134	33.0	45,072	70,112	35.7
MAIN	39,955	68,942	42.0	40,412	68,552	41.0
MAPP (U.S.)	24,042	32,769	26.6	24,525	33,822	27.5
NPCC (U.S.)	47,850	73,123	34.6	47,757	74,989	36.3
SERC	133,244	179,810	25.9	136,565	182,596	25.2
SPP	27,828	45,989	39.5	27,771	46,381	40.1
WECC (U.S.)	100,337	152,158	34.1	102,472	151,125	32.2
Contiguous U.S.	**583,430**	**877,397**	**33.5**	**594,354**	**892,004**	**33.4**
	2005/ 2006			2006/ 2007		
ECAR	87,101	134,419	35.2	89,020	139,179	36.0
ERCOT	43,034	82,609	47.9	43,923	83,405	47.3
FRCC	43,094	53,944	20.1	44,233	54,604	19.0
MAAC	45,816	71,205	35.7	46,556	70,755	34.2
MAIN	41,324	72,014	42.6	41,947	73,739	43.1
MAPP (U.S.)	24,931	34,181	27.1	25,313	34,497	26.6
NPCC (U.S.)	48,303	76,623	37.0	48,811	80,117	39.1
SERC	139,138	185,340	24.9	142,203	186,463	23.7
SPP	28,156	45,854	38.6	28,395	46,209	38.6
WECC (U.S.)	104,600	156,297	33.1	106,930	164,503	35.0
Contiguous U.S.	**605,497**	**912,486**	**33.6**	**617,331**	**933,471**	**33.9**
	2007/ 2008			2008/ 2009		
ECAR	91,032	140,209	35.1	93,520	141,709	34.0
ERCOT	44,829	83,405	46.3	45,753	83,341	45.1
FRCC	45,309	55,804	18.8	46,481	56,738	18.1
MAAC	47,291	70,755	33.2	48,021	70,755	32.1
MAIN	42,480	74,019	42.6	43,191	76,134	43.3
MAPP (U.S.)	25,634	35,312	27.4	26,067	35,560	26.7
NPCC (U.S.)	49,275	83,548	41.0	49,667	83,336	40.4
SERC	144,978	188,342	23.0	147,873	189,990	22.2
SPP	28,833	46,384	37.8	29,414	45,888	35.9
WECC (U.S.)	109,278	166,835	34.5	111,645	167,747	33.4
Contiguous U.S.	**628,939**	**944,613**	**33.4**	**641,632**	**951,198**	**32.5**

Notes: • Actual data are final. • Projected data are updated annually. • NERC Regional Council names may be found in the Glossary reference. • Represents an hour of a day during the associated peak period. • The winter peak period begins on December 1 and extends through March 31 of the following year. For example, winter 2003/2004 begins December 1, 2003, and extends through March 31, 2004. • Totals may not equal sum of components because of independent rounding.

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

Chapter 4. Fuel

Table 4.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1992 through 2003

Type of Power Producer and Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million btu)[3]
Total (All Sectors)				
1992	805,140	172,241	3,899,718	141,279
1993	842,153	192,462	3,928,653	136,230
1994	848,796	183,618	4,367,148	136,381
1995	860,594	132,578	4,737,871	132,520
1996	907,209	144,626	4,312,458	158,560
1997	931,949	159,715	4,564,770	119,412
1998	946,295	222,640	5,081,384	124,988
1999	949,802	207,871	5,321,984	126,387
2000	994,933	195,228	5,691,481	125,971
2001	972,691	216,672	5,832,305	97,308
2002	987,583	168,597	6,126,062	131,230
2003	1,014,058	206,653	5,616,135	156,306
Electricity Generators, Electric Utilities				
1992	779,860	152,329	2,765,608	--
1993	813,508	168,556	2,682,440	--
1994	817,270	155,377	2,987,146	--
1995	829,007	105,956	3,196,507	--
1996	874,681	116,680	2,732,107	--
1997	900,361	132,147	2,968,453	--
1998	910,867	187,461	3,258,054	--
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	5,182
2003	757,384	118,087	1,763,764	6,078
Electricity Generators, Independent Power Producers				
1992	1,326	2,099	63,389	43
1993	3,050	1,965	72,653	122
1994	3,939	1,998	77,414	96
1995	3,921	2,342	91,064	87
1996	4,143	2,169	91,617	71
1997	3,884	4,010	70,774	642
1998	9,486	9,676	285,878	1,345
1999	30,572	30,037	615,756	696
2000	107,745	45,011	1,049,636	1,951
2001	139,799	60,489	1,477,643	92
2002	192,274	44,993	1,998,782	354
2003	226,154	68,817	2,016,550	171
Combined Heat and Power, Electric Power[4]				
1992	12,204	3,291	495,967	11,753
1993	13,293	8,513	589,147	11,895
1994	14,904	12,011	693,923	11,928
1995	14,926	11,366	806,202	18,080
1996	15,575	11,320	836,086	15,494
1997	14,764	11,046	863,968	13,773
1998	13,773	12,310	871,881	21,406
1999	13,197	12,440	914,600	13,627
2000	15,634	13,147	921,341	16,871
2001	15,455	11,175	978,563	9,352
2002	15,174	11,942	1,149,812	19,958
2003	19,498	8,431	1,128,935	23,317
Combined Heat and Power, Commercial[5]				
1992	371	429	32,674	1,170
1993	404	672	37,435	1,115
1994	404	694	40,828	1,172
1995	569	649	42,700	--
1996	656	645	42,380	*
1997	630	790	38,975	23
1998	440	802	40,693	54
1999	481	931	39,045	*
2000	514	823	37,029	*
2001	532	1,023	36,248	*
2002	477	834	32,545	*
2003	582	894	38,480	--
Combined Heat and Power, Industrial[6]				
1992	11,379	14,093	542,081	128,313
1993	11,898	12,755	546,978	123,098
1994	12,279	13,537	567,836	123,185
1995	12,171	12,265	601,397	114,353
1996	12,153	13,813	610,268	142,995
1997	12,311	11,723	622,599	104,974
1998	11,728	12,392	624,878	102,183
1999	11,432	12,595	639,165	112,064
2000	11,706	10,459	640,381	107,149
2001	10,636	10,530	653,565	87,864
2002	11,855	11,608	685,239	105,737
2003	10,440	10,424	668,407	126,739

[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.

* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is "1" and values under 0.5 are shown as "*".)
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding.

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

Table 4.2. Consumption of Fossil Fuels for Useful Thermal Output by Type of Combined Heat and Power Producers, 1992 through 2003

Type of Power Producer and Year	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total Combined Heat and Power				
1992	19,372	24,077	717,860	199,858
1993	19,750	26,394	733,584	177,554
1994	20,609	27,929	784,015	179,595
1995	20,418	25,562	834,382	180,895
1996	20,806	27,873	865,774	187,290
1997	21,005	28,802	868,569	187,680
1998	20,320	28,845	949,106	208,828
1999	20,373	26,822	982,958	223,713
2000	20,466	22,266	985,263	230,082
2001	18,944	18,268	898,286	166,161
2002	17,561	14,811	860,019	146,882
2003	17,720	17,939	721,267	137,838
Electric Power[4]				
1992	1,704	1,229	122,908	6,033
1993	1,794	1,591	128,743	3,865
1994	2,241	1,791	144,062	6,487
1995	2,376	2,784	142,753	5,430
1996	2,520	2,424	147,091	4,912
1997	2,355	2,466	161,608	9,684
1998	2,493	1,322	172,471	6,329
1999	3,033	1,423	175,757	4,435
2000	3,107	1,412	192,253	6,641
2001	2,910	1,171	199,808	5,849
2002	2,255	841	263,619	7,448
2003	2,080	1,596	225,967	11,601
Commercial				
1992	804	807	29,672	116
1993	968	843	27,738	148
1994	940	931	31,457	215
1995	850	596	34,964	--
1996	1,005	601	40,075	--
1997	1,108	794	47,941	25
1998	1,002	1,006	46,527	41
1999	1,009	682	44,991	--
2000	1,034	792	47,844	--
2001	916	809	42,407	--
2002	929	416	41,430	--
2003	1,234	555	19,973	--
Industrial				
1992	16,864	22,041	565,279	193,709
1993	16,988	23,960	577,103	173,541
1994	17,428	25,207	608,496	172,893
1995	17,192	22,182	656,665	175,465
1996	17,281	24,848	678,608	182,378
1997	17,542	25,541	659,021	177,971
1998	16,824	26,518	730,108	202,458
1999	16,330	24,718	762,210	219,278
2000	16,325	20,062	745,165	223,441
2001	15,119	16,287	656,071	160,312
2002	14,377	13,555	554,970	139,434
2003	14,406	15,788	475,327	126,237

[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.

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

Table 4.3. Consumption of Fossil Fuels for Electricity Generation and for Useful Thermal Output, 1992 through 2003

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1992	824,512	196,318	4,617,578	341,137
1993	861,904	218,855	4,662,236	313,784
1994	869,405	211,547	5,151,163	315,976
1995	881,012	158,140	5,572,253	313,415
1996	928,015	172,499	5,178,232	345,850
1997	952,955	188,517	5,433,338	307,092
1998	966,615	251,486	6,030,490	333,816
1999	970,175	234,694	6,304,942	350,100
2000	1,015,398	217,494	6,676,744	356,053
2001	991,635	234,940	6,730,591	263,469
2002	1,005,144	183,408[R]	6,986,081	278,111
2003	1,031,778	224,593	6,337,402	294,143
Electricity Generators, Electric Utilities				
1992	779,860	152,329	2,765,608	--
1993	813,508	168,556	2,682,440	--
1994	817,270	155,377	2,987,146	--
1995	829,007	105,956	3,196,507	--
1996	874,681	116,680	2,732,107	--
1997	900,361	132,147	2,968,453	--
1998	910,867	187,461	3,258,054	--
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	--
2003	757,384	118,087	1,763,764	6,078
Electricity Generators, Independent Power Producers				
1992	1,326	2,099	63,389	--
1993	3,050	1,965	72,653	--
1994	3,939	1,998	77,414	--
1995	3,921	2,342	91,064	--
1996	4,143	2,169	91,617	--
1997	3,884	4,010	70,774	--
1998	9,486	9,676	285,878	--
1999	30,572	30,037	615,756	--
2000	107,745	45,011	1,049,636	--
2001	139,799	60,489	1,477,643	--
2002	192,274	44,993	1,998,782	--
2003	226,154	68,817	2,016,550	171
Combined Heat and Power, Electric Power				
1992	13,908	4,521	618,875	17,786
1993	15,087	10,104	717,890	15,760
1994	17,145	13,803	837,985	18,415
1995	17,302	14,149	948,954	23,510
1996	18,096	13,744	983,177	20,406
1997	17,118	13,512	1,025,575	23,457
1998	16,266	13,632	1,044,352	27,735
1999	16,230	13,864	1,090,356	18,062
2000	18,741	14,559	1,113,595	23,512
2001	18,365	12,346	1,178,371	15,201
2002	17,430	12,783	1,413,431	27,406
2003	21,578	10,028	1,354,901	34,918
Combined Heat and Power, Commercial				
1992	1,175	1,235	62,346	1,286
1993	1,373	1,515	65,173	1,263
1994	1,344	1,625	72,285	1,387
1995	1,419	1,245	77,664	--
1996	1,660	1,246	82,455	--
1997	1,738	1,584	86,915	48
1998	1,443	1,807	87,220	95
1999	1,490	1,613	84,037	--
2000	1,547	1,615	84,874	--
2001	1,448	1,832	78,655	--
2002	1,405	1,250	73,975	--
2003	1,816	1,449	58,453	--
Combined Heat and Power, Industrial				
1992	28,244	36,135	1,107,361	322,022
1993	28,886	36,715	1,124,081	296,639
1994	29,707	38,744	1,176,332	296,078
1995	29,363	34,448	1,258,063	289,818
1996	29,434	38,661	1,288,876	325,373
1997	29,853	37,265	1,281,620	282,945
1998	28,553	38,910	1,354,986	304,641
1999	27,763	37,312	1,401,374	331,342
2000	28,031	30,520	1,385,546	330,590
2001	25,755	26,817	1,309,636	248,176
2002	26,232	25,163	1,240,209	245,171
2003	24,846	26,212	1,143,734	252,976

[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.

R = Revised.

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

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

Table 4.4. End-of-Year Stocks of Coal and Petroleum by Type of Producer, 1992 through 2003

Period	Electric Power Sector		Electric Utilities		Independent Power Producers[1]	
	Coal (Thousand Tons)[2]	Petroleum (Thousand Barrels)[3]	Coal (Thousand Tons)[2]	Petroleum (Thousand Barrels)[3]	Coal (Thousand Tons)[2]	Petroleum (Thousand Barrels)[3]
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	141,604	54,109	129,041	46,169	12,563	7,940
2000	102,296	40,932	90,115	30,502	12,180	10,430
2001	138,496	57,031	117,147	37,308	21,349	19,723
2002	141,714	52,490	116,952	31,243	24,761	21,247
2003	121,567	53,170	97,831	29,953	23,736	23,218

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

NA = Not available.

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

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

Table 4.5. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1992 through 2003

Period	Coal[1]				Petroleum[2]				Natural Gas[3]		All Fossil Fuels
	Receipts	Average Cost		Avg. Sulfur Percent by Weight	Receipts	Average Cost		Avg. Sulfur Percent by Weight	Receipts	Average Cost	Average Cost
	(thousand tons)	(cents/ 10^6 Btu)	(dollars/ ton)		(thousand barrels)	(cents/ 10^6 Btu)	(dollars/ barrel)		(thousand Mcf)	(cents/ 10^6 Btu)	(cents/ 10^6 Btu)
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	1.34	2,574,523	256.0	159.4
1994	831,929	135.5	28.03	1.17	149,258	242.3	15.19	1.23	2,863,904	223.0	152.5
1995	826,860	131.8	27.01	1.08	89,908	256.6	16.10	1.21	3,023,327	198.4	145.2
1996	862,701	128.9	26.45	1.10	113,678	302.6	18.98	1.26	2,604,663	264.1	151.8
1997	880,588	127.3	26.16	1.11	128,749	273.0	17.18	1.37	2,764,734	276.0	152.0
1998	929,448	125.2	25.64	1.06	181,276	202.1	12.71	1.48	2,922,957	238.1	143.5
1999	908,232	121.6	24.72	1.01	145,939	235.9	14.81	1.51	2,809,455	257.4	143.8
2000	790,274	120.0	24.28	.93	108,272	417.9	26.30	1.33	2,629,986	430.2	173.5
2001	762,815	123.2	24.68	.89	124,618	369.3	23.20	1.42	2,148,924[R]	448.7	173.0
2002[4]	884,287	125.5	25.52	.94	120,851	334.3	20.77	1.64	5,607,737	356.0	151.5
2003[5]	1,026,281	127.5	25.91	.94	205,283	445.1	27.34	1.55	5,479,821	536.6	218.7

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.
[4] Beginning in 2002, data from the Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" for independent power producers and combined heat and power producers are included in this data dissemination. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the FERC Form 423.
[5] For 2003 only, estimates were developed for missing or incomplete data from some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 data cannot be directly compared to previous years' data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes.

R = Revised.

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

Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 4.6. Receipts and Quality of Coal Delivered for the Electric Power Industry, 1992 through 2003

Period	Anthracite[1]			Bituminous[1]			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight
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
2002[2]	--	--	--	412,589	1.47	10.1	391,785	.36	6.2	65,600	.93	13.3
2003[3]	--	--	--	461,074	1.49	10.0	449,916	.37	6.4	79,724	.94	13.3

[1] Beginning in 2001, anthracite coal receipts were no longer reported separately. From 2001 forward, all anthracite coal receipts have been combined with bituminous coal receipts.
[2] Beginning in 2002, data from the Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" for independent power producers and combined heat and power producers are included in this data dissemination. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the FERC Form 423.
[3] For 2003 only, estimates were developed for missing or incomplete data from some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 data cannot be directly compared to previous years' data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes.

Notes: • Totals may not equal sum of components because of independent rounding. • Data do not include waste coal and synthetic coal. • Receipts data for regulated utilities are compiled by EIA from data collected by the Federal Energy Regulatory Commission (FERC) on the FERC Form 423. These data are collected by FERC for regulatory rather than statistical and publication purposes. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. Nonutility data include fuel delivered to electric generating plants with a total fossil-fueled nameplate generating capacity of 50 or more megawatts; utility data include fuel delivered to plants whose total fossil-fueled steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity is 50 or more megawatts.

Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 4.7. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 1992 through 2003

Year	Coal[1]			Petroleum[2]		Natural Gas[3]
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon[R]	Sulfur Percent by Weight	Average Btu per Cubic Foot
1992	10,395	1.29	9.71	150,293	1.19	1,024
1993	10,315	1.18	9.55	149,983	1.34	1,023
1994	10,338	1.17	9.36	149,324	1.23	1,023
1995	10,248	1.08	9.23	149,371	1.21	1,019
1996	10,263	1.10	9.22	149,367	1.26	1,017
1997	10,275	1.11	9.36	149,838	1.37	1,019
1998	10,241	1.06	9.18	149,736	1.48	1,022
1999	10,163	1.01	9.01	149,407	1.51	1,019
2000	10,115	.93	8.84	149,857	1.33	1,020
2001	10,200[R]	.89	8.80	147,857	1.42	1,020
2002[4]	10,157	.94	8.74	143,493	1.64	1,021
2003[5]	10,071	.94	8.67	145,507	1.55	1,025

[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] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.
[4] Beginning in 2002, data from the Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" for independent power producers and combined heat and power producers are included in this data dissemination. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the FERC Form 423.
[5] For 2003 only, estimates were developed for missing or incomplete data from some facilities reporting on the FERC Form 423. This was not done for earlier years. Therefore, 2003 data cannot be directly compared to previous years' data. Additional information regarding the estimation procedures that were used is provided in the Technical Notes.

R = Revised.

Notes: • Totals may not equal sum of components because of independent rounding. • Receipts data for regulated utilities are compiled by EIA from data collected by the Federal Energy Regulatory Commission (FERC) on the FERC Form 423. These data are collected by FERC for regulatory rather than statistical and publication purposes. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. Nonutility data include fuel delivered to electric generating plants with a total fossil-fueled nameplate generating capacity of 50 or more megawatts; utility data include fuel delivered to plants whose total fossil-fueled steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity is 50 or more megawatts.

Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Chapter 5. Emissions

Table 5.1. Emissions from Energy Consumption for Electricity Production and Useful Thermal Output at Combined-Heat-and-Power Plants, 1992 through 2003
(Thousand Metric Tons)[1]

Emission	2003	2002[R]	2001[R]	2000[R]	1999[R]	1998[R]	1997[R]	1996[R]	1995[R]	1994[R]	1993[R]	1992[R]
Carbon Dioxide (CO_2).....	2,408,961	2,397,937	2,379,603	2,429,394	2,326,558	2,313,013	2,223,347	2,155,453	2,079,761	2,063,788	2,034,206	1,951,425
Sulfur Dioxide (SO_2)	10,594	10,515	10,966	11,297	12,445	12,509	13,524	12,908	11,898	14,473	14,968	15,031
Nitrogen Oxides (NO_x) ...	4,396	4,802	5,045	5,380	5,732	6,235	6,324	6,281	7,885	7,802	7,997	7,728

[1] All historical values have been revised due to the inclusion of emissions related to the consumption of fuel for the production of useful thermal output at combined heat and power plants. The emission estimates reported in earlier issues of the Electric Power Annual included emissions solely for fuel consumed to produce electricity.

R = Revised.

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

Table 5.2. Number and Capacity of Fossil-Fueled Steam-Electric Generators with Environmental Equipment, 1992 through 2003

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)
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....................................	236[R]	97,988[R]	1,273[R]	360,762[R]	616[R]	189,396[R]	1,485[R]	390,821[R]
2002....................................	243[R]	98,673[R]	1,256[R]	359,338[R]	670[R]	200,670[R]	1,522[R]	401,341[R]
2003....................................	246	99,567	1,244	358,009	695	210,928	1,546	409,954

[1] Includes plants under the Clean Air Act that were monitored by the Environmental Protection Agency even if sold to an unregulated entity.
[2] Components are not additive since some generators are included in more than one category.
[3] Nameplate capacity

R = Revised.

Notes: • These data are for plants with a fossil-fueled steam-electric capacity of 100 megawatts or more . • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report." Data for unregulated plants are included beginning with 2001 data.

Table 5.3. Average Flue Gas Desulfurization Costs, 1992 through 2003

Year[1]	Average Overhead & Maintenance Costs (mills per kilowatthour)[2]	Average Installed Capital Costs (dollars per kilowatt)
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..	1.27[R]	130.80[R]
2002..	1.11[R]	124.18[R]
2003..	1.23	123.75

[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.

R = Revised.

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

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report." Data for unregulated plants are included beginning with 2001 data.

Chapter 6. Trade

Table 6.1. Electric Power Industry - Purchases, 1992 through 2003
(Million Kilowatthours)

	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
U.S. Total	**2,668,989**	**2,663,607**	**3,073,611**	**2,345,540**	**2,039,969**	**2,020,622**	**1,966,447**	**1,797,720**	**1,617,715**	**1,528,222**	**1,492,370**	**1,395,789**
Electric Utilities	2,563,947	2,579,671	2,976,254	2,250,382	1,949,574	1,927,198	1,878,099	1,694,192	1,528,068	1,435,591	1,407,419	1,312,605
IPP[1]	37,921	15,801	97,357[2]	95,158	90,395	93,423	88,348	103,528	89,647	92,631	84,951	83,184
CHP	67,122	68,135	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]

[1] IPP are independent power producers and CHP are combined heat and power producers.
[2] The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001, and after 2001 should be done with caution.
[3] For 1992 through 2001, CHP purchases are combined with IPP data above.

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

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

Table 6.2. Electric Power Industry - Sales for Resale, 1992 through 2003
(Million Kilowatthours)

	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
U.S. Total	**2,972,466**	**2,766,242**	**2,899,787[R]**	**2,358,094[R]**	**1,988,090[R]**	**1,921,859[R]**	**1,838,539**	**1,656,090**	**1,495,015**	**1,387,966**	**1,387,137**	**1,284,273**
Electric Utilities	1,781,761	1,793,748	2,087,789[R]	1,715,582	1,635,614	1,664,081	1,616,318	1,431,179	1,276,356	1,185,352	1,200,047	1,119,948
IPP[1]	1,156,796	943,531	811,998[2]	642,511[R]	362,475[R]	257,778[R]	222,221	224,911	218,660	202,614	187,090	164,324
CHP	33,909	28,963	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]	--[3]

[1] IPP are independent power producers and CHP are combined heat and power producers.
[2] The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001, and after 2001 should be done with caution.
[3] For 1992 through 2001, CHP sales are combined with IPP data above.

R = Revised.

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

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

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1992 through 2003
(Megawatthours)

Description	2003	2002[R]	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Electricity Imports and Exports												
Canada												
Imports	29,319,707	36,130,480	38,401,598	48,515,476	42,911,308	39,502,108	43,008,501	42,233,376	40,596,119	44,821,858	29,364,197	26,224,179
Exports	23,582,184	12,995,708	16,105,612	12,684,706	12,953,488	11,683,276	7,470,332	1,986,361	2,468,244	941,214	2,691,723	1,835,692
Mexico[1]												
Imports[2]	1,069,926	242,597	98,649	76,800	303,439	11,249	22,729	1,263,152	2,257,411	2,011,319	1,993,328	2,022,419
Exports	390,190	564,603	367,680	2,144,676	1,268,284	1,973,203	1,503,707	1,315,625	1,154,421	1,068,668	849,167	990,887
Total Imports	**30,389,633**	**36,373,077**	**38,500,247**	**48,592,276**	**43,214,747**	**39,513,357**	**43,031,230**	**43,496,528**	**42,853,530**	**46,833,177**	**31,357,525**	**28,246,598**
Total Exports	**23,972,374**	**13,560,311**	**16,473,292**	**14,829,382**	**14,221,772**	**13,656,479**	**8,974,039**	**3,301,986**	**3,622,665**	**2,009,882**	**3,540,890**	**2,826,579**

[1] For the reporting year 2001,California - ISO reported electricity purchases from Mexico of 98,645 MWh. They exported 65,475 MWh, thereby having a total net trade of 33,170 MWh of imported electricity in 2001. For the reporting year 2002, California - ISO reported electricity purchases from Mexico of 143,948 MWh. They exported 196,923 MWh, thereby having a total net trade of 52,975 MWh of exported electricity in 2002. In 2003, California - ISO reported electricity purchases of 971,278 MWh and sold 22,510 MWh.
[2] Includes contract terminations in 1997 and 2000.

R = Revised.

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

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

Chapter 7. Retail Customers, Sales, and Revenue

Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1992 through 2003
(Number)

Period	Residential	Commercial	Industrial	Transportation[1]	Other[2]	All Sectors
Total Electric Industry						
1992	99,512,728	12,367,205	547,990	NA	857,614	113,285,537
1993	100,860,071	12,526,377	553,231	NA	795,298	114,734,977
1994	102,320,846	12,733,153	583,935	NA	850,770	116,488,704
1995	103,917,312	12,949,365	580,626	NA	882,422	118,329,725
1996	105,343,005	13,181,065	586,198	NA	893,884	120,004,152
1997	107,065,589	13,542,374	563,223	NA	951,863	122,123,049
1998	109,048,343	13,887,066	539,903	NA	932,838	124,408,150
1999	110,383,238	14,073,764	552,690	NA	935,311	125,945,003
2000	111,717,711	14,349,067	526,554	NA	974,185	127,567,517
2001	114,317,707	14,939,895	574,361	NA	1,008,212	130,840,175
2002	116,448,459	15,277,434	595,319	NA	1,041,821	133,363,033
2003	117,092,348	16,636,448	719,748	1,281	NA	134,449,825
Full-Service Providers						
1992	99,512,728	12,367,205	547,990	NA	857,614	113,285,537
1993	100,860,071	12,526,377	553,231	NA	795,298	114,734,977
1994	102,320,846	12,733,153	583,935	NA	850,770	116,488,704
1995	103,917,312	12,949,365	580,626	NA	882,422	118,329,725
1996	105,341,408	13,180,632	586,169	NA	893,884	120,002,093
1997	107,033,338	13,540,374	562,972	NA	951,863	122,088,547
1998	108,736,845	13,832,662	538,167	NA	932,838	124,040,512
1999	109,817,057	13,963,937	527,329	NA	934,260	125,242,583
2000	110,505,820	14,058,271	512,551	NA	953,756	126,030,398
2001	112,533,187	14,535,461	558,381	NA	1,001,641	128,628,670
2002[3]	113,785,576	14,933,773	586,846	NA	1,034,571	130,340,766
2003[2]	114,843,890	16,132,739	698,452	1,105	NA	131,676,186
Energy-Only Providers						
1992	--	--	--	--	--	--
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	1,597	433	29	NA	0	2,059
1997	32,251	2,000	251	NA	0	34,502
1998	311,498	54,404	1,736	NA	0	367,638
1999	566,181	109,827	25,361	NA	1,051	702,420
2000	1,211,891	290,796	14,003	NA	20,429	1,537,119
2001	1,784,520	404,434	15,980	NA	6,571	2,211,505
2002	2,662,883	343,661	8,473	NA	7,250	3,022,267
2003	2,248,458	503,709	21,296	176	NA	2,773,639

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

[2] Beginning in 2003, miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, and interdepartmental sales previously reported in "Other" appears in the Commercial sector. Sales to railroads and railways, previously reported in "Other", appears in the Transportation sector.

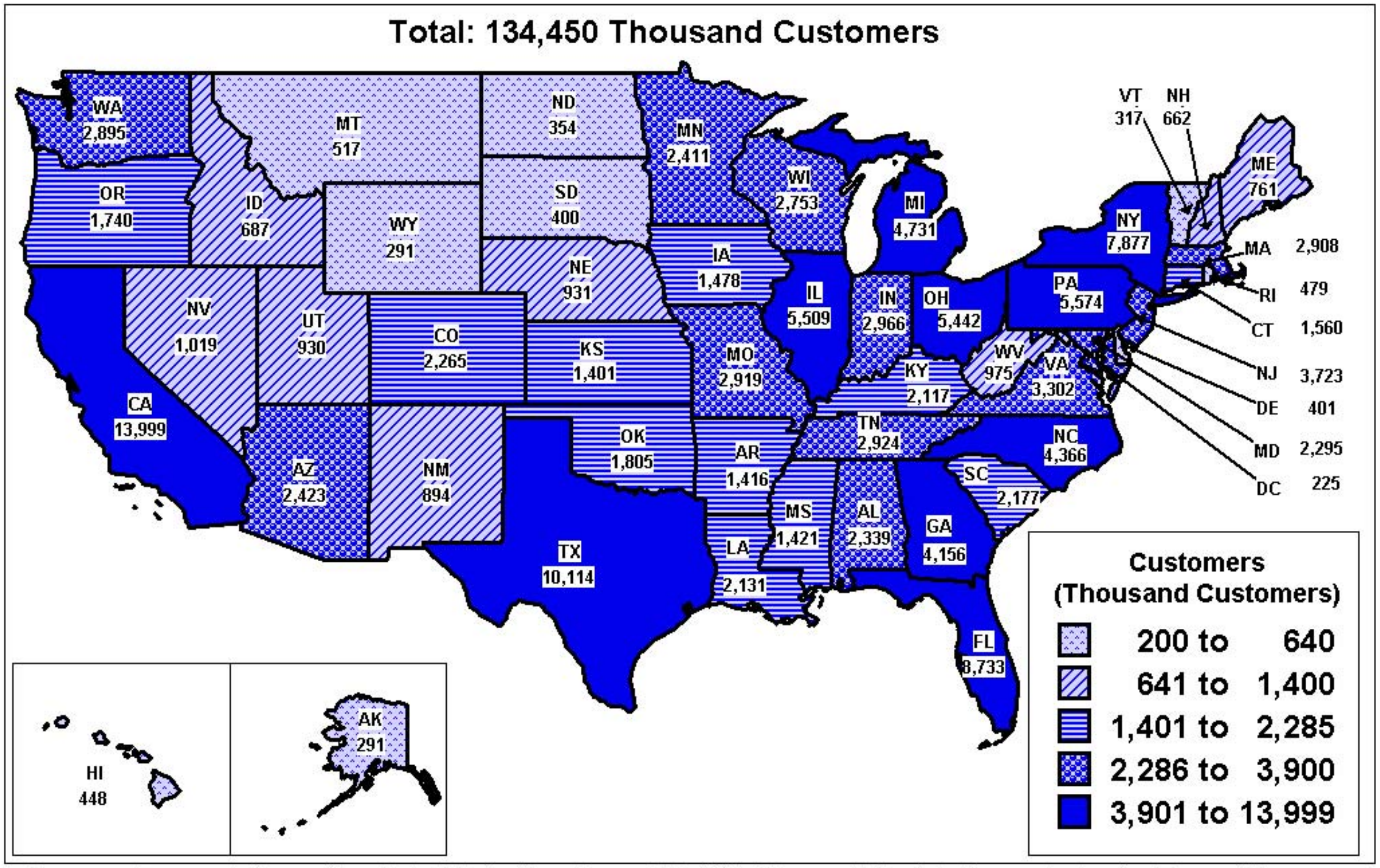
[3] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."

NA = Not available.

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

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

Figure 7.1 U.S. Electric Power Industry Total Ultimate Customers by State, 2003



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

Table 7.2. Direct Use and Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1992 through 2003
(Megawatthours)

Period	Sales					End Use		
	Residential	Commercial	Industrial	Trans-portation[1]	Other[2]	Retail Sales	Direct Use[3]	All Sectors
Total Electric								
1992	935,938,788	761,270,543	972,713,990	NA	93,442,150	2,763,365,474[R]	133,841,244	2,897,206,718
1993	994,780,818	794,573,370	977,164,250	NA	94,943,902	2,861,462,340	139,237,877	3,000,700,217
1994	1,008,481,682	820,269,462	1,007,981,245	NA	97,830,475	2,934,562,864	146,325,334	3,080,888,198
1995	1,042,501,471	862,684,775	1,012,693,350	NA	95,406,993	3,013,286,589	150,676,540	3,163,963,129
1996	1,082,511,751	887,445,174	1,033,631,379	NA	97,538,719	3,101,127,023	152,638,016	3,253,765,039
1997	1,075,880,098	928,632,774	1,038,196,892	NA	102,900,664	3,145,610,428	156,238,898	3,301,849,326
1998	1,130,109,120	979,400,928	1,051,203,115	NA	103,517,589	3,264,230,752	160,865,884	3,425,096,636
1999	1,144,923,069	1,001,995,720	1,058,216,608	NA	106,951,684	3,312,087,081	171,629,285	3,483,716,366
2000	1,192,446,491	1,055,232,090	1,064,239,393	NA	109,496,292	3,421,414,266	170,942,509	3,592,356,775
2001	1,202,646,738	1,089,153,700	964,224,282	NA	113,756,089	3,369,780,809	162,648,615	3,532,429,424
2002	1,266,959,182	1,116,247,776	972,167,724	NA	107,146,152	3,462,520,834	166,184,296	3,628,705,130
2003	1,273,486,349	1,199,718,148	1,007,988,089	6,999,392	NA	3,488,191,978	168,294,526	3,656,486,504
Full-Service								
1992	935,938,788	761,270,543	972,713,990	NA	93,442,150	2,763,365,474	NA	2,763,365,474
1993	994,780,818	794,573,370	977,164,250	NA	94,943,902	2,861,462,340	NA	2,861,462,340
1994	1,008,481,682	820,269,462	1,007,981,245	NA	97,830,475	2,934,562,864	NA	2,934,562,864
1995	1,042,501,471	862,684,775	1,012,693,350	NA	95,406,993	3,013,286,589	NA	3,013,286,589
1996	1,082,490,541	887,424,657	1,030,356,028	NA	97,538,719	3,097,809,945	NA	3,097,809,945
1997	1,075,766,590	928,440,265	1,032,653,445	NA	102,900,664	3,139,760,964	NA	3,139,760,964
1998	1,127,734,988	968,528,009	1,040,037,873	NA	103,517,589	3,239,818,459	NA	3,239,818,459
1999	1,140,761,016	970,600,943	1,017,783,037	NA	106,754,043	3,235,899,039	NA	3,235,899,039
2000	1,183,137,429	1,000,865,367	1,017,722,945	NA	107,824,323	3,309,550,064	NA	3,309,550,064
2001	1,168,538,228	1,020,839,106	930,011,833	NA	105,436,926	3,224,826,093	NA	3,224,826,093
2002[4]	1,232,709,137	1,022,093,194	933,655,019	NA	101,943,663	3,290,401,013	NA	3,290,401,013
2003[4]	1,240,575,668	1,092,046,639	923,299,631	3,325,163	NA	3,259,247,101	NA	3,259,247,101
Energy-Only								
1992	--	--	--	--	--	--	--	--
1993	--	--	--	--	--	--	--	--
1994	--	--	--	--	--	--	--	--
1995	--	--	--	--	--	--	--	--
1996	21,210	20,517	3,275,351	NA	0	3,317,078	NA	3,317,078
1997	113,508	192,509	5,543,447	NA	0	5,849,464	NA	5,849,464
1998	2,374,132	10,872,919	11,165,242	NA	0	24,412,293	NA	24,412,293
1999	4,162,053	31,394,777	40,433,571	NA	197,641	76,188,042	NA	76,188,042
2000	9,309,062	54,366,723	46,516,448	NA	1,671,969	111,864,202	NA	111,864,202
2001	34,108,510	68,314,594	34,212,449	NA	8,319,163	144,954,716	NA	144,954,716
2002	34,250,045	94,154,582	38,512,705	NA	5,202,489	172,119,821	NA	172,119,821
2003	32,910,681	107,671,509	84,688,458	3,674,229	NA	228,944,877	NA	228,944,877

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

[2] Beginning in 2003, miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, and interdepartmental sales previously reported in "Other" appears in the Commercial sector. Sales to railroads and railways, previously reported in "Other", appears in the Transportation sector.

[3] Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales among adjusted or co-located facilities for which revenue information is not available.

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

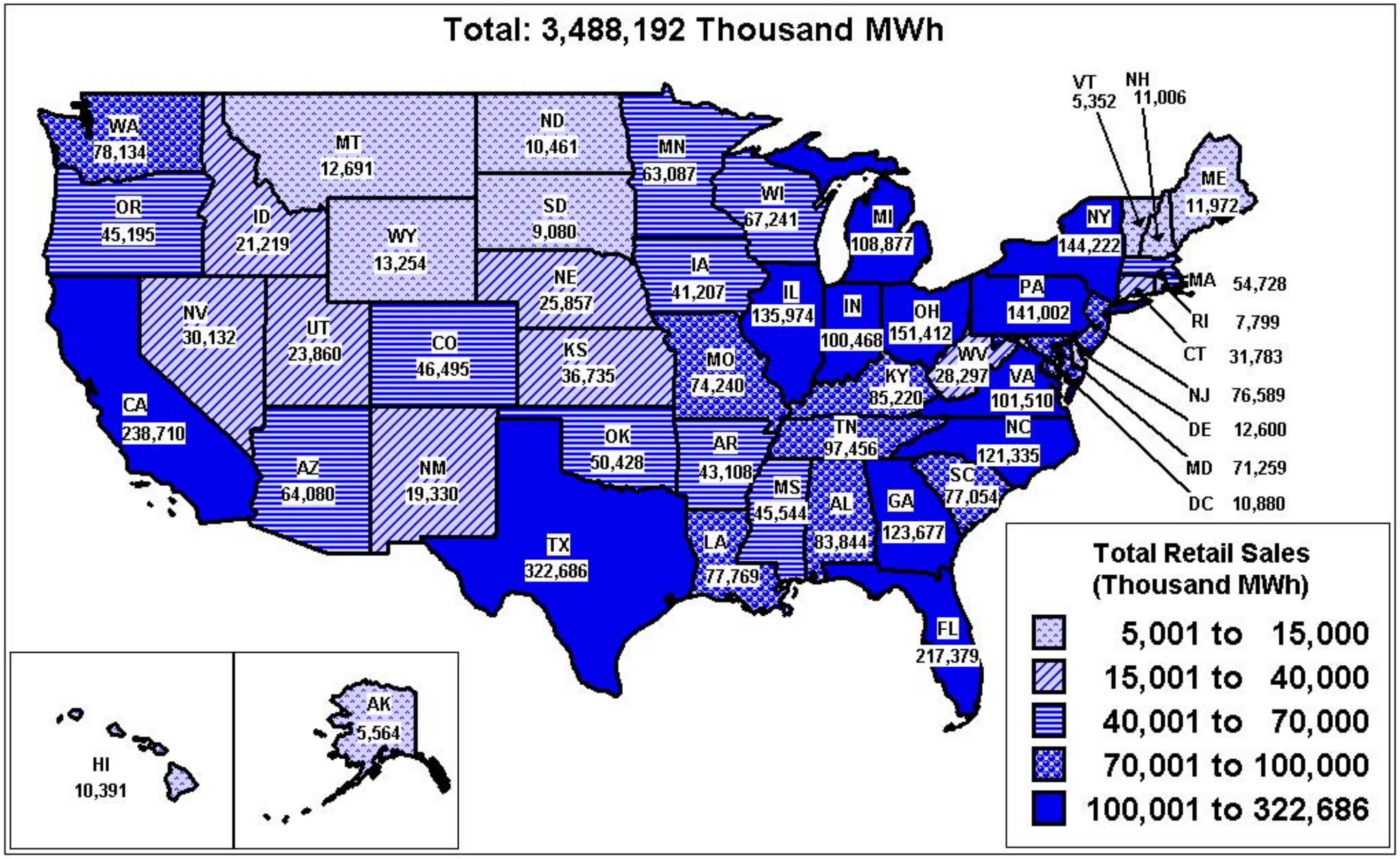
NA = Not available.

R = Revised.

Notes: • See Glossary reference for definitions. • Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within limits specified by a rate schedule. • Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. • As a consequence of unrecoverable high average wholesale power costs in California in 2000 and early 2001, the credit ratings of California's three major investor-owned utilities fell below investment grade by early 2001. The rapid and dramatic decline in the credit-worthiness of California's major investor-owned utilities virtually eliminated their ability through wholesale markets to meet the power requirements of their retail consumers. In response to the looming energy shortfall, the California State legislature authorized the California Department of Water Resources (CDWR), using its undamaged borrowing capability, to enter the wholesale markets on behalf of the California retail consumer effective on January 17, 2001 and for the period ending December 31, 2002. Also the California Public Utility Commission (CPUC) was required by statute to establish the procedures for facilitating the CDWR's participation in California retail sales, as well as retail revenue recovery mechanisms. CDWR's continued commitment to the California ratepayers is related to long-term contracts for resources that will last for years. Energy provided by the CDWR was delivered by the major investor-owned utilities in California. For this reason, and by agreement with the CDWR, energy sales for the calendar year 2002 of approximately 45.2 million megawatthours and 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, 2003 (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, 1992 through 2003
(Million Dollars)

Period	Residential	Commercial	Industrial	Transportation[1]	Other[2]	All Sectors
Total Electric Industry						
1992	76,848	58,343	46,993	NA	6,296	188,480
1993	82,814	61,521	47,357	NA	6,528	198,220
1994	84,552	63,396	48,069	NA	6,689	202,706
1995	87,610	66,365	47,175	NA	6,567	207,717
1996	90,503	67,829	47,536	NA	6,741	212,609
1997	90,704	70,497	47,023	NA	7,110	215,334
1998	93,360	72,575	47,050	NA	6,863	219,848
1999	93,483	72,771	46,846	NA	6,796	219,896
2000	98,209	78,405	49,369	NA	7,179	233,163
2001	103,671	86,354	48,573	NA	7,999	246,597
2002	107,229	87,706	47,485	NA	7,208	249,629
2003	110,779	95,772	51,716	531	NA	258,798
Full-Service Providers						
1992	76,848	58,343	46,993	NA	6,296	188,480
1993	82,814	61,521	47,357	NA	6,528	198,220
1994	84,552	63,396	48,069	NA	6,689	202,706
1995	87,610	66,365	47,175	NA	6,567	207,717
1996	90,501	67,827	47,385	NA	6,741	212,455
1997	90,694	70,482	46,772	NA	7,110	215,059
1998	93,164	71,769	46,550	NA	6,863	218,346
1999	93,142	70,492	45,056	NA	6,783	215,473
2000	97,086	73,704	46,465	NA	6,988	224,243
2001	100,004	79,901	46,040	NA	7,242	233,187
2002[3]	102,842	78,189	44,276	NA	6,762	232,070
2003[3]	106,885	84,934	45,998	224	NA	238,042
Energy-Only Providers[4]						
1992	--	--	--	--	--	--
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	2	2	151	NA	0	154
1997	10	15	251	NA	0	275
1998	196	806	500	NA	0	1,502
1999	340	2,279	1,791	NA	13	4,423
2000	530	3,175	2,374	NA	75	6,153
2001	2,607	4,978	1,984	NA	640	10,209
2002	2,510	6,189	1,938	NA	246	10,884
2003	2,210	6,870	4,121	228	NA	13,434
Delivery-Only Service						
1992	--	--	--	--	--	--
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	593	1,527	531	NA	116	2,767
2001	1,060	1,475	549	NA	117	3,201
2002	1,876	3,328	1,270	NA	200	6,675
2003	1,683	3,968	1,597	79	NA	7,322

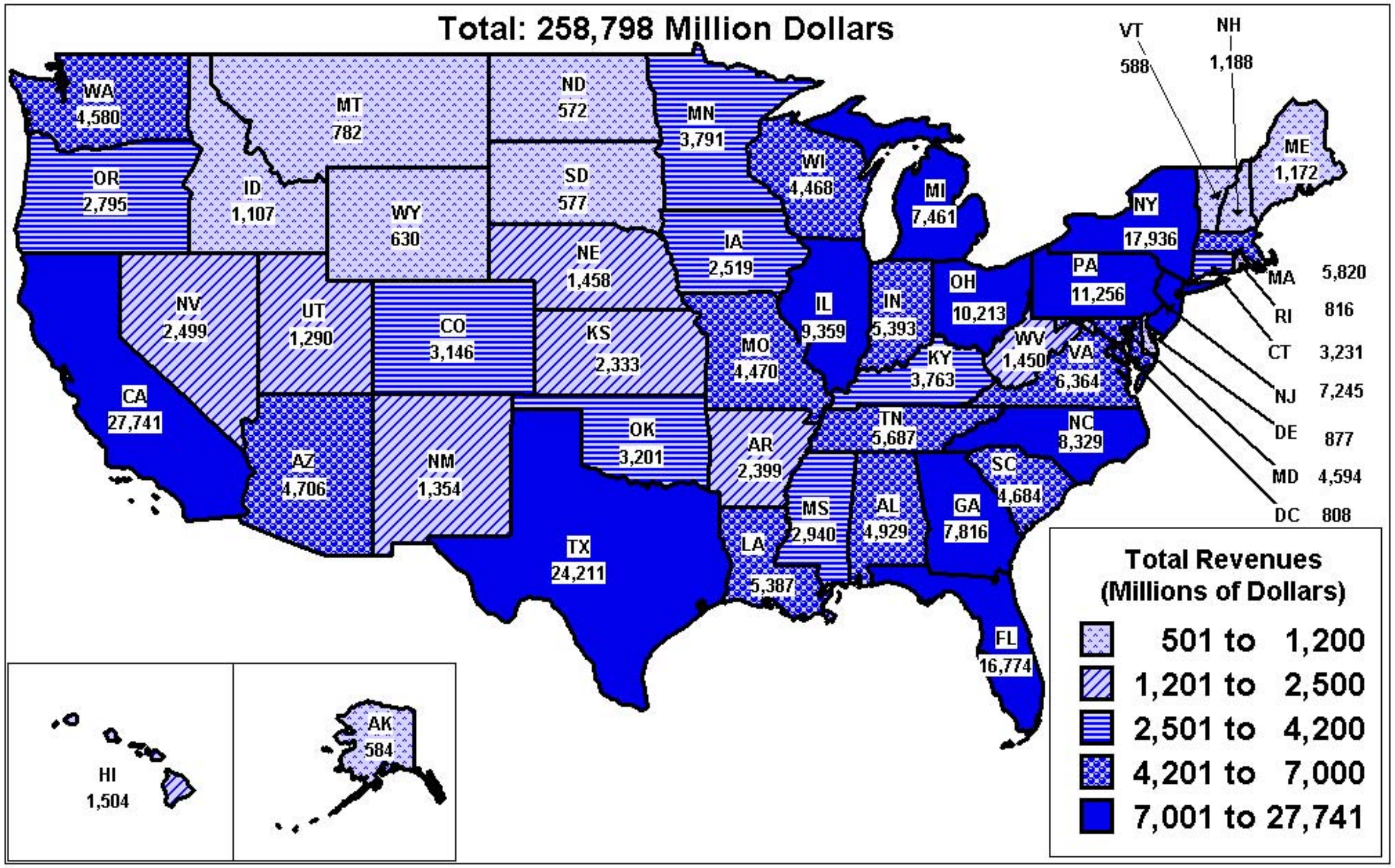
[1] Beginning in 2003 the Other Sector has been eliminated. Data previously assigned to the Other Sector have been reclassified as follows: Lighting for public buildings, streets, and highways, interdepartamental sales, and other sales to public authorities are now included in the Commercial Sector; agricultural and irrigation sales where separately identified are now included in the Industrial Sector; and a new sector, Transportation, now includes electrified rail and various urban transit systems (such as automated guideway, trolley, and cable) where the principal propulsive energy source is electricity. Comparisons of data across years should include consideration of these reclassification changes.
[2] Beginning in 2003, miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, and interdepartmental sales previously reported in "Other" appears in the Commercial sector. Sales to railroads and railways, previously reported in "Other", appears in the Transportation sector.
[3] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."
[4] From 1996 to 1999, revenue estimated based on retail sales reported on the Form EIA-861.

NA = Not available.

Notes: • See Glossary reference for definitions. • Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by a rate schedule. • Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. • As a consequence of unrecoverable high average wholesale power costs in California in 2000 and early 2001, the credit ratings of California's three major investor-owned utilities fell below investment grade by early 2001. The rapid and dramatic decline in the credit-worthiness of California's major investor-owned utilities virtually eliminated their ability through wholesale markets to meet the power requirements of their retail consumers. In response to the looming energy shortfall, the California State legislature authorized the California Department of Water Resources (CDWR), using its undamaged borrowing capability, to enter the wholesale markets on behalf of the California retail consumer effective on January 17, 2001 and for the period ending December 31, 2002. Also the California Public Utility Commission (CPUC) was required by statute to establish the procedures for facilitating the CDWR's participation in California retail sales, as well as retail revenue recovery mechanisms. CDWR's continued commitment to the California ratepayers is related to long-term contracts for resources that will last for years. Energy provided by the CDWR was delivered by the major investor-owned utilities in California. For this reason, and by agreement with the CDWR, energy sales for the calendar year 2002 of approximately 45.2 million megawatthours and 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, 2003 (Millions of Dollars)



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

Table 7.4. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, 1992 through 2003
(Cents per kilowatthour)

Period	Residential	Commercial	Industrial	Transportation[1]	Other[2]	All Sectors
Total Electric Industry						
1992	8.21	7.66	4.83	NA	6.74	6.82
1993	8.32	7.74	4.85	NA	6.88	6.93
1994	8.38	7.73	4.77	NA	6.84	6.91
1995	8.40	7.69	4.66	NA	6.88	6.89
1996	8.36	7.64	4.60	NA	6.91	6.86
1997	8.43	7.59	4.53	NA	6.91	6.85
1998	8.26	7.41	4.48	NA	6.63	6.74
1999	8.16	7.26	4.43	NA	6.35	6.64
2000	8.24	7.43	4.64	NA	6.56	6.81
2001	8.62	7.93	5.04	NA	7.03	7.32
2002	8.46	7.86	4.88	NA	6.73	7.21
2003	8.70	7.98	5.13	7.58	NA	7.42
Full-Service Providers						
1992	8.21	7.66	4.83	NA	6.74	6.82
1993	8.32	7.74	4.85	NA	6.88	6.93
1994	8.38	7.73	4.77	NA	6.84	6.91
1995	8.40	7.69	4.66	NA	6.88	6.89
1996	8.36	7.64	4.60	NA	6.91	6.86
1997	8.43	7.59	4.53	NA	6.91	6.85
1998	8.26	7.41	4.48	NA	6.63	6.74
1999	8.16	7.26	4.43	NA	6.35	6.66
2000	8.21	7.36	4.57	NA	6.48	6.78
2001	8.56	7.83	4.95	NA	6.87	7.23
2002[3]	8.34	7.65	4.74	NA	6.63	7.05
2003[3]	8.62	7.78	4.98	6.74	NA	7.30
Energy-Only Providers[4]						
1992	--	--	--	--	--	--
1993	--	--	--	--	--	--
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	8.36	7.64	4.60	NA	--	6.86
1997	8.43	7.59	4.53	NA	--	6.85
1998	8.26	7.41	4.48	NA	--	6.74
1999	8.16	7.26	4.43	NA	6.35	6.66
2000	12.07	8.65	6.24	NA	11.42	7.97
2001	10.75	9.45	7.41	NA	9.09	9.25
2002	12.81	10.11	8.33	NA	8.58	10.20
2003	11.83	10.07	6.75	8.35	NA	9.07

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

[2] Beginning in 2003, miscellaneous sales, such as sales for public street and highway lighting, other sales to public authorities, and interdepartmental sales previously reported in "Other" appears in the Commercial sector. Sales to railroads and railways, previously reported in "Other", appears in the Transportation sector.

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

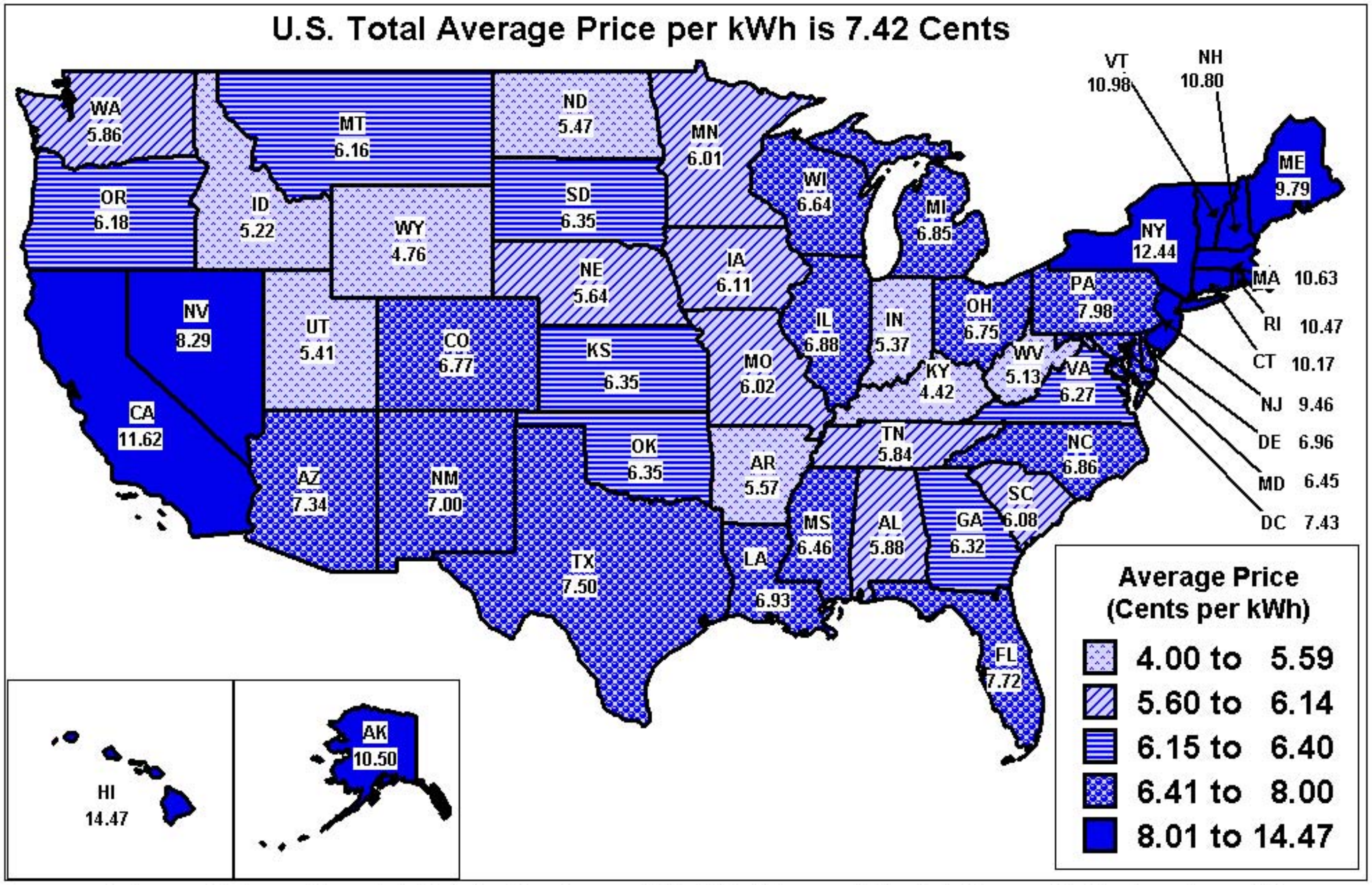
[4] From 1996 to 1999, average revenue estimated based on retail sales reported on the Form EIA-861.

NA = Not available.

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

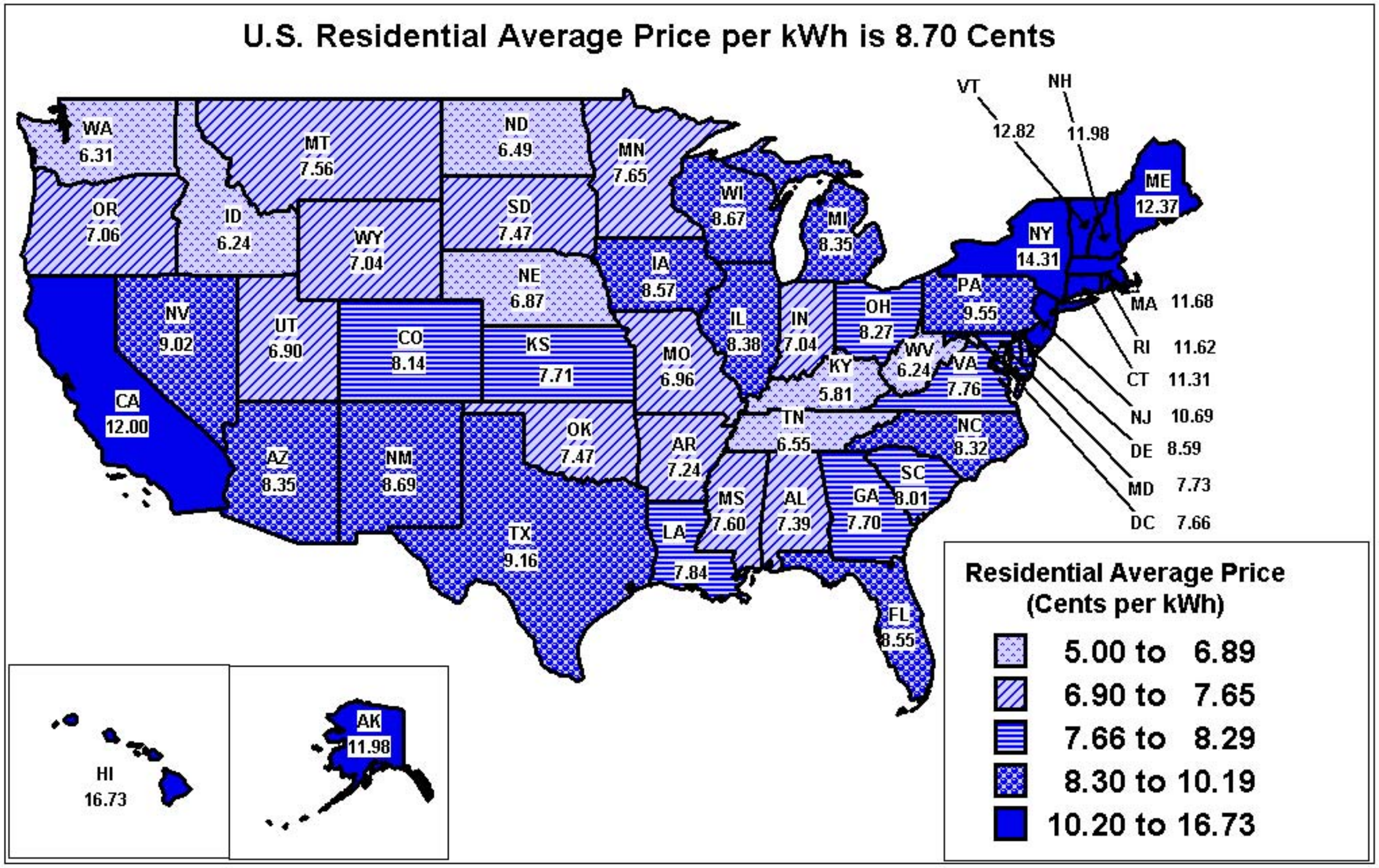
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.4 U.S. Electric Industry Average Retail Price of Electricity by State, 2003 (Cents per kWh)



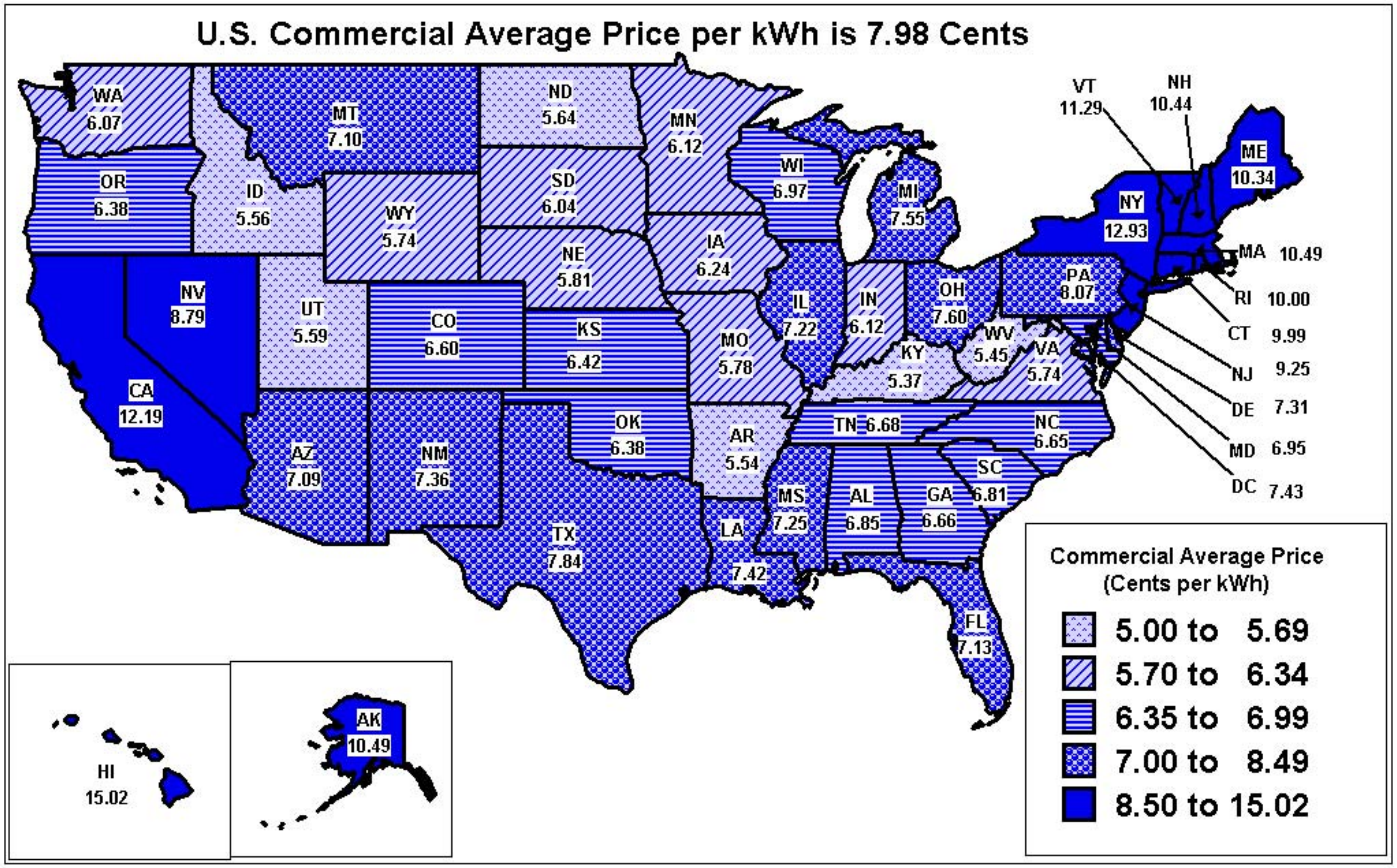
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.5 U.S. Electric Industry Residential Average Retail Price of Electricity by State, 2003 (Cents per kWh)



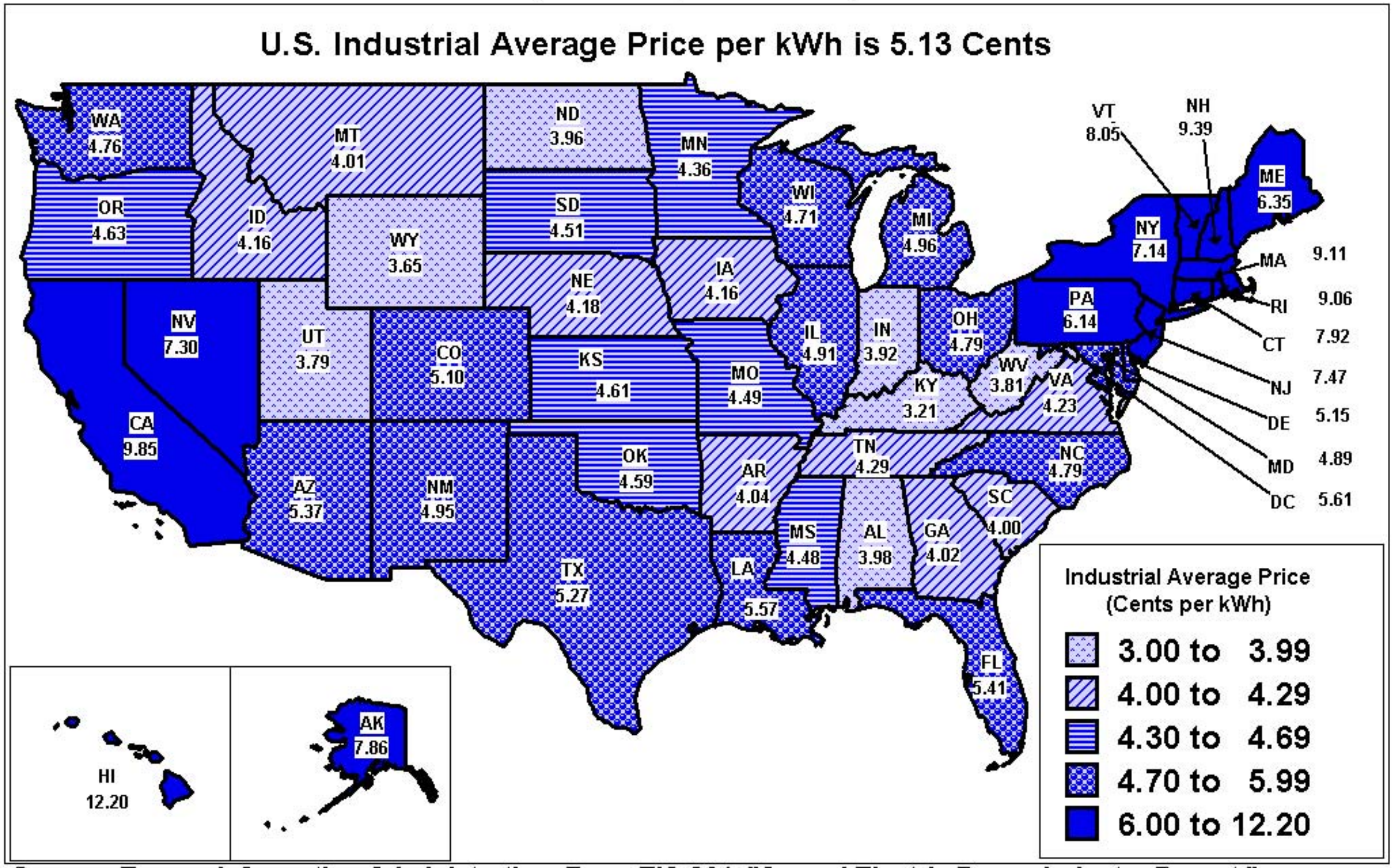
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.6 U.S. Electric Industry Commercial Average Retail Price of Electricity by State, 2003 (Cents per kWh)



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

Figure 7.7 U.S. Electric Industry Industrial Average Retail Price of Electricity by State, 2003 (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, 1992 through 2003
(Million Dollars)

Description	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Utility Operating Revenues	**226,227**	**219,389**	**267,525**	**235,336**	**214,160**	**218,175**	**215,083**	**207,459**	**199,967**	**196,282**	**193,638**	**185,493**
Electric Utility	202,369	200,135	244,219	214,707	197,578	201,970	195,898	188,901	183,655	179,307	176,354	169,488
Other Utility	23,858	19,254	23,306	20,630	16,583	16,205	19,185	18,558	16,312	16,974	17,283	16,005
Utility Operating Expenses	**197,459**	**188,745**	**235,198**	**210,324**	**182,258**	**186,498**	**182,796**	**173,920**	**165,321**	**164,207**	**161,908**	**153,682**
Electric Utility	175,473	171,291	213,733	191,329	167,266	171,689	165,443	156,938	150,599	148,663	146,118	139,009
Operation	122,723	116,374	159,929	132,662	108,461	110,759	104,337	97,207	91,881	93,108	91,328	87,272
Production	96,181	90,649	136,089	107,352	83,555	85,956	80,153	73,437	68,983	69,269	68,781	66,980
Cost of Fuel	26,476	24,132	29,490	32,555	29,826	31,252	31,861	30,706	29,122	30,108	31,214	30,254
Purchased Power	62,173	58,828	98,231	61,969	43,258	42,612	37,991	32,987	29,981	29,213	27,716	26,212
Other	7,532	7,688	8,368	12,828	10,470	12,092	10,301	9,744	9,880	9,948	9,851	10,513
Transmission	3,585	3,494	2,365	2,699	2,423	2,197	1,915	1,503	1,425	1,361	1,354	1,308
Distribution	3,185	3,113	3,217	3,115	2,956	2,804	2,700	2,604	2,561	2,581	2,595	2,499
Customer Accounts	4,180	4,165	4,434	4,246	4,195	4,021	3,767	3,848	3,613	3,546	3,418	3,347
Customer Service	1,893	1,821	1,856	1,839	1,889	1,955	1,917[R]	1,920	1,922	1,956	1,852	1,531
Sales	234	261	282	403	492	514	501	435	348	232	203	199
Administrative and General	13,466	12,872	11,686	13,009	12,951	13,311	13,384	13,458	13,028	14,163	13,124	11,409
Maintenance	11,141	10,843	11,167	12,185	12,276	12,486	12,368	12,050	11,767	12,022	12,447	12,195
Depreciation	16,962	17,319	20,845	22,761	23,968	24,122	23,072	21,194	19,885	18,679	18,099	17,092
Taxes and Other	24,648	26,755	21,792	23,721	22,561	24,322	25,667	26,488	27,065	24,854	24,244	22,450
Other Utility	21,986	17,454	21,465	18,995	14,992	14,809	17,353	16,983	14,722	15,544	15,790	14,673
Net Utility Operating Income	**28,768**	**30,644**	**32,327**	**25,012**	**31,902**	**31,677**	**32,286**	**33,539**	**34,646**	**32,074**	**31,730**	**31,811**

R = Revised.
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, 1992 through 2003
(Mills per Kilowatthour)

Plant Type	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Operation												
Nuclear	8.86	8.54	8.30	8.41	8.93	9.98	11.02	9.47	9.43	9.79	10.20	10.43
Fossil Steam	2.50	2.54	2.40	2.31	2.21	2.17	2.22	2.25	2.38	2.32	2.37	2.38
Hydroelectric[1]	4.50	5.07	5.79	4.74	4.17	3.85	3.29	3.87	3.69	4.53	3.82	4.33
Gas Turbine and Small Scale[2]	2.76	2.72	3.15	4.57	5.16	3.85	4.43	5.08	3.57	4.58	6.47	10.18
Maintenance												
Nuclear	5.23	5.04	5.01	4.93	5.13	5.79	6.90	5.68	5.21	5.20	5.73	5.93
Fossil Steam	2.73	2.68	2.61	2.45	2.38	2.41	2.43	2.49	2.65	2.82	2.96	2.95
Hydroelectric[1]	3.01	3.58	3.97	2.99	2.60	2.00	2.49	2.08	2.19	2.90	2.65	3.30
Gas Turbine and Small Scale[2]	2.26	2.38	3.33	3.50	4.80	3.43	3.43	4.98	4.28	5.39	7.52	12.15
Fuel												
Nuclear	4.60	4.60	4.67	4.95	5.17	5.39	5.42	5.50	5.75	5.87	5.88	6.12
Fossil Steam	17.35	16.11	18.13	17.69	15.62	15.94	16.80	16.51	16.07	16.67	17.65	17.49
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small Scale[2]	43.91	31.82	43.56	39.19	28.72	23.02	24.94	30.58	20.83	22.19	26.39	28.59
Total												
Nuclear	18.69	18.18	17.98	18.28	19.23	21.16	23.33	20.65	20.39	20.86	21.80	22.48
Fossil Steam	22.59	21.32	23.14	22.44	20.22	20.52	21.45	21.25	21.11	21.80	22.97	22.83
Hydroelectric[1]	7.51	8.65	9.76	7.73	6.77	5.86	5.78	5.95	5.89	7.43	6.47	7.63
Gas Turbine and Small Scale[2]	48.93	36.93	50.04	47.26	38.68	30.30	32.80	40.64	28.67	32.16	40.38	50.92

[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), 1992 through 2003

(Million Dollars)

Description	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Operating Revenue - Electric	**33,906**	**32,776**	**38,028**	**31,843**	**26,767**	**26,155**	**25,397**	**24,207**	**23,473**	**23,267**	**22,522**	**21,686**
Operating Expenses - Electric	**29,637**	**28,638**	**32,789**	**26,244**	**21,274**	**20,880**	**20,425**	**19,084**	**18,959**	**18,649**	**18,162**	**17,191**
Operation Including Fuel	**22,642**	**21,731**	**25,922**	**19,575**	**15,386**	**15,120**	**14,917**	**13,768**	**13,653**	**13,578**	**13,242**	**12,527**
Production	17,948	17,176	21,764	15,742	11,923	11,608	11,481	11,080	10,385	10,445	10,254	9,712
Transmission	872	858	785	781	732	773	725	344	628	610	580	535
Distribution	696	680	605	574	516	603	538	497	426	430	408	389
Customer Accounts	582	537	600	507	415	390	390	365	323	317	315	299
Customer Service	280	315	263	211	160	127	133	103	102	104	94	83
Sales	84	74	73	66	49	51	46	18	20	22	17	18
Administrative and General	2,180	2,090	1,832	1,695	1,591	1,567	1,602	1,360	1,769	1,651	1,573	1,492
Maintenance	**2,086**	**1,926**	**1,904**	**1,815**	**1,686**	**1,631**	**1,609**	**1,638**	**1,575**	**1,584**	**1,565**	**1,565**
Depreciation and Amortization	**3,844**	**3,907**	**4,009**	**3,919**	**3,505**	**3,459**	**3,239**	**3,160**	**2,934**	**2,721**	**2,596**	**2,417**
Taxes and Tax Equivalents	**1,066**	**1,074**	**954**	**936**	**697**	**670**	**660**	**662**	**797**	**766**	**759**	**681**
Net Electric Operating Income	**4,268**	**4,138**	**5,238**	**5,598**	**5,493**	**5,275**	**4,972**	**5,123**	**4,514**	**4,618**	**4,360**	**4,496**

Notes: • Totals may not equal sum of components because of independent rounding. • The 1998-2003 data represent those utilities meeting a threshold of 150 million kilowatthours sales to ultimate customers and/or 150 million kilowatthours of sales for resale for the two previous years. The 1992-1997 data represent those utilities meeting a threshold of 120 million kilowatthours sales to ultimate customers and/or 120 million kilowatthours of sales for resale for the two previous years.

Source: Energy Information Administration, EIA Form-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.4. Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (Without Generation Facilities), 1992 through 2003

(Million Dollars)

Description	2003[1]	2002[1]	2001[1]	2000	1999	1998	1997	1996	1995	1994	1993	1992
Operating Revenue - Electric	**12,454**	**11,546**	**10,417**	**9,904**	**9,354**	**8,790**	**8,586**	**8,582**	**8,435**	**7,996**	**7,523**	**7,247**
Operating Expenses - Electric	**11,481**	**10,703**	**9,820**	**9,355**	**8,737**	**8,245**	**8,033**	**8,123**	**7,979**	**7,567**	**7,063**	**6,844**
Operation Including Fuel	**10,095**	**9,439**	**8,864**	**8,424**	**7,874**	**7,437**	**7,117**	**7,359**	**7,173**	**6,858**	**6,425**	**6,245**
Production	8,865	8,311	7,863	7,486	7,015	6,661	6,240	6,578	6,422	6,185	5,761	5,617
Transmission	105	93	61	64	48	44	57	51	35	34	34	33
Distribution	348	320	311	280	261	230	304	234	204	190	189	176
Customer Accounts	172	163	164	155	143	130	139	141	125	119	117	109
Customer Service	31	39	26	22	22	21	16	18	18	17	17	16
Sales	11	10	15	16	14	9	13	12	10	10	9	12
Administrative and General	562	504	423	402	371	342	348	325	358	303	298	282
Maintenance	**418**	**389**	**304**	**286**	**272**	**263**	**338**	**244**	**250**	**234**	**207**	**193**
Depreciation and Amortization	**711**	**631**	**405**	**394**	**369**	**330**	**354**	**322**	**313**	**274**	**257**	**251**
Taxes and Tax Equivalents	**257**	**244**	**247**	**251**	**223**	**215**	**225**	**206**	**244**	**201**	**175**	**155**
Net Electric Operating Income	**974**	**843**	**597**	**549**	**617**	**545**	**552**	**459**	**457**	**429**	**460**	**404**

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

Notes: • Totals may not equal sum of components because of independent rounding. • The 1998-2003 data represent those utilities meeting a threshold of 150 million kilowatthours sales to ultimate customers and/or 150 million kilowatthours of sales for resale for the two previous years. The 1992-1997 data represent those utilities meeting a threshold of 120 million kilowatthours sales to ultimate customers and/or 120 million kilowatthours of sales for resale for the two previous years.

Source: Energy Information Administration, EIA Form-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.5. Revenue and Expense Statistics for U.S. Federally Owned Electric Utilities, 1992 through 2003
(Million Dollars)

Description	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Operating Revenue - Electric	**11,798**	**11,470**	**12,458**	**10,685**	**10,186**	**9,780**	**8,833**	**9,082**	**8,743**	**8,552**	**8,141**	**7,872**
Operating Expenses - Electric	**8,763**	**8,665**	**10,013**	**8,139**	**7,775**	**7,099**	**5,999**	**6,390**	**6,162**	**6,303**	**6,056**	**5,883**
Operation Including Fuel	**6,498**	**6,419**	**7,388**	**5,873**	**5,412**	**5,184**	**4,073**	**4,514**	**4,615**	**4,877**	**4,827**	**4,595**
Production	5,175	5,236	6,247	5,497	4,890	4,735	3,686	4,109	4,219	4,464	4,272	4,144
Transmission	307	244	354	332	349	323	327	328	290	304	319	272
Distribution	1	1	1	2	2	2	1	1	2	2	2	2
Customer Accounts	4	10	16	6	1	1	1	3	2	4	4	3
Customer Service	63	60	60	48	50	51	42	46	29	28	27	26
Sales	20	6	6	10	28	14	13	7	41	9	6	5
Administrative and General	927	862	705	467	528	535	444	451	431	442	578	537
Maintenance	**600**	**566**	**521**	**488**	**436**	**476**	**441**	**432**	**398**	**377**	**381**	**394**
Depreciation and Amortization	**1,335**	**1,351**	**1,790**	**1,471**	**1,623**	**1,175**	**1,214**	**1,187**	**896**	**746**	**611**	**653**
Taxes and Tax Equivalents	**329**	**328**	**315**	**308**	**304**	**264**	**272**	**256**	**252**	**56**	**237**	**241**
Net Electric Operating Income	**3,035**	**2,805**	**2,445**	**2,546**	**2,411**	**2,681**	**2,834**	**2,692**	**2,581**	**2,249**	**2,085**	**1,989**

Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.6. Revenue and Expense Statistics for U.S. Cooperative Borrower Owned Electric Utilities, 1992 through 2003
(Million Dollars)

Description	2003	2002[R]	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Operating Revenue - Electric	**29,228**	**27,458**	**26,458**	**25,629**	**23,824**	**23,988**	**23,321**	**24,424**	**24,609**	**23,777**	**24,873**	**23,325**
Operation and Maintenance Expenses	**26,361**	**24,561**	**23,763**	**22,982**	**21,283**	**21,223**	**20,715**	**23,149**	**21,741**	**20,993**	**21,675**	**20,353**
Operation Including Fuel	**24,076**	**22,383**	**21,703**	**20,942**	**19,336**	**19,280**	**18,405**	**20,748**	**19,334**	**18,650**	**19,292**	**18,038**
Production	19,559	18,143	17,714	17,080	15,706	15,683	15,105	17,422	15,907	15,471	16,101	15,059
Transmission	637	579	524	525	466	452	339	372	366	322	336	324
Distribution	1,787	1,681	1,589	1,530	1,451	1,440	1,134	1,133	1,127	1,053	1,044	980
Customer Accounts	579	545	532	487	455	446	382	375	383	374	386	369
Customer Service	140	136	119	133	132	132	118	118	112	105	101	95
Sales	79	79	88	82	81	77	61	72	72	61	57	52
Administrative and General	1,295	1,219	1,137	1,104	1,045	1,050	1,266	1,257	1,367	1,265	1,265	1,160
Depreciation and Amortization	**2,076**	**1,992**	**1,895**	**1,820**	**1,747**	**1,732**	**1,727**	**1,787**	**1,778**	**1,742**	**1,768**	**1,709**
Taxes and Tax Equivalents	**209**	**186**	**164**	**220**	**200**	**211**	**583**	**614**	**628**	**601**	**616**	**605**
Net Electric Operating Income	**2,867**	**2,897**	**2,696**	**2,647**	**2,541**	**2,764**	**2,606**	**2,872**	**2,868**	**2,784**	**3,197**	**2,973**

R = Revised.
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, 1992 through 2003
(Megawatts)

Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Total Actual Peak Load Reduction[1]	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**	**23,069**	**17,204**
Energy Efficiency	13,581	13,420	13,027	12,873	13,452	13,591	13,326	14,243	13,212	11,662	10,368	7,890
Load Management	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,347	13,340	12,701	9,314

[1] Represents the actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Load Reduction). Actual peak load reduction is reported by large utilities only, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2003 and 120 million kilowatthours in 1992-1997.

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

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

Table 9.2. Demand-Side Management Program Annual Effects by Program Category, 1992 through 2003

Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
	Annual Effects – Energy Efficiency											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243	13,212	11,662	10,368	7,890
Energy Savings (Thousand MWh)	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119	31,779
	Annual Effects – Load Management											
Large Utilities[1]												
Actual Peak Load Reduction (MW)	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,349	13,339	12,701	9,314
Potential Peak Load Reductions (MW)[3]	25,290	26,888	27,730	28,496	30,118	27,840	27,911	34,101	33,817	31,255	29,140	24,552
Energy Savings (Thousand MWh)	2,020	1,790	1,816	875	872	392	953	1,989	2,093	2,763	4,175	4,114

[1] Represents the actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Load Reduction). Actual peak load reduction is reported by large utilities only, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2003 and 120 million kilowatthours in 1992-1997.

[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.

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, 1992 through 2003

Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
	Incremental Effects – Energy Efficiency											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	945	1,054	999	720	695	796	1,065	1,381	1,561	1,751	1,839	1,501
Energy Savings (Thousand MWh)	2,939	3,543	4,402	3,284	3,027	3,324	4,661	6,361	7,901	8,054	8,601	5,338
Small Utilities[3]												
Actual Peak Load Reduction (MW)[2]	90	49	20	25	22	12	12	2	7	9	9	17
Energy Savings (Thousand MWh)	8	192	8	8	8	37	10	7	16	11	12	12
	Incremental Effects – Load Management											
Large Utilities[1]												
Actual Peak Load Reduction (MW)[2]	1,084	1,160	1,297	919	1,568	1,821	1,261	5,027	3,039	1,418	2,809	2,437
Potential Peak Load Reductions (MW)[4]	1,981	2,655	2,448	2,439	6,457	2,832	2,475	2,309	4,930	5,153	5,298	6,077
Energy Savings (Thousand MWh)	29	65	905	63	67	37	171	482	321	178	508	447
Small Utilities[3]												
Actual Peak Load Reduction (MW)[2]	81	54	45	137	54	124	130	50	29	56	110	315
Potential Peak Load Reductions (MW)[4]	131	76	177	190	84	160	183	90	41	81	291	657
Energy Savings (Thousand MWh)	4	2	4	9	2	7	19	6	3	8	11	37

[1] Represents the actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Load Reduction). Actual peak load reduction is reported by large utilities only, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2003 and 120 million kilowatthours in 1992-1997.

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

[3] Refers to electric utilities with annual sales to ultimate customers or sales for resale less than 150 million kilowatthours in 1998-2001 and 120 million kilowatthours in 1992-1997.

[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.

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, 1992 through 2003

Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Actual Peak Load Reductions[1] (MW)												
Large Utilities[2]												
Residential	9,431	9,137	9,619	9,446	9,976	9,327	10,799	11,471	10,930	9,638	8,851	7,606
Commercial	6,774	6,839	8,210	6,987	7,777	9,482	8,174	8,678	8,057	6,927	7,541	4,598
Industrial	6,594	6,500	6,553	6,141	6,360	7,927	5,812	9,083	10,033	7,977	6,270	4,467
Transportation	105	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	460	573	327	2,342	495	498	661	545	460	407	532
Total	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**	**23,069**	**17,204**
Potential Peak Load Reductions[3] (MW)												
Large Utilities[2]												
Residential	12,525	12,072	12,274	12,970	12,812	13,022	16,662	14,697	14,047	13,851	12,868	11,058
Commercial	8,943	9,298	10,469	9,114	8,868	12,210	12,896	12,452	11,495	9,915	11,821	7,002
Industrial	17,298	18,321	17,344	18,775	17,237	15,512	11,035	20,275	20,715	18,271	13,957	13,367
Transportation	105	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	617	670	510	4,653	686	644	921	772	881	862	1,014
Total	**38,871**	**40,308**	**40,757**	**41,369**	**43,570**	**41,430**	**41,237**	**48,344**	**47,029**	**42,917**	**39,508**	**32,442**
Energy Savings (Thousand MWh)												
Large Utilities[2]												
Residential	13,469	15,438	16,027	16,287	16,263	16,564	17,830	20,585	20,253	21,028	19,241	15,322
Commercial	25,089	24,391	24,217	25,660	23,375	25,125	27,898	29,186	26,187	21,773	16,567	12,301
Industrial	11,156	11,339	11,313	9,160	8,156	3,347	8,684	10,493	9,620	8,568	8,644	7,192
Transportation	551	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	2,907	3,206	2,593	2,770	831	1,694	1,578	1,360	1,114	842	748
Total	**50,265**	**54,075**	**54,762**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**	**45,294**	**35,563**

[1] Represents the actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Load Reduction). Actual peak load reduction is reported by large utilities only, those with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2003 and 120 million kilowatthours in 1992-1997.
[2] Refers to electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2003 and 120 million kilowatthours in 1992-1997.
[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, 1992 through 2003

Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Actual Peak Load Reductions[1] (MW)												
Large Utilities[2]												
Residential	640	895	790	572	605	599	743	792	860	1,083	1,147	1,112
Commercial	528	527	742	515	684	1176	699	935	1176	1,244	1,427	1,251
Industrial	849	680	640	502	929	799	836	1,870	2,426	785	2,014	1,451
Transportation	12	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	112	124	50	45	43	48	93	139	57	61	108
Total	**2,029**	**2,214**	**2,296**	**1,640**	**2,263**	**2,617**	**2,326**	**3,690**	**4,601**	**3,169**	**4,648**	**3,922**
Small Utilities[3]												
Residential	88	48	32	37	27	35	40	30	20	27	76	139
Commercial	58	41	15	37	22	34	21	9	10	7	35	32
Industrial	25	12	16	62	7	56	61	8	4	24	47	113
Transportation	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	0	0	26	19	10	20	5	2	6	28	48
Total	**171**	**101**	**63**	**162**	**76**	**136**	**142**	**52**	**36**	**65**	**185**	**332**
U.S. Total	**2,200**	**2,317**	**2,361**	**1,802**	**2,339**	**2,753**	**2,468**	**3,742**	**4,637**	**3,234**	**4,833**	**4,254**
Potential Peak Load Reductions[4] (MW)												
Large Utilities[2]												
Residential	752	1,311	900	699	753	751	960	950	1,231	1,467	NA	NA
Commercial	602	751	1,115	565	718	1,863	853	1,512	1,697	2,115	NA	NA
Industrial	1,551	1,506	1,277	1,815	5,612	1,438	1,669	3,800	3,368	1,997	NA	NA
Transportation	21	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	141	155	79	68	76	58	146	195	326	NA	NA
Total	**2,926**	**3,709**	**3,447**	**3,159**	**7,151**	**3,628**	**3,540**	**6,408**	**6,491**	**5,905**	**7,157**	**7,578**
Small Utilities[3]												
Residential	116	64	158	55	41	49	59	46	27	38	NA	NA
Commercial	73	43	19	51	25	41	35	17	13	12	NA	NA
Industrial	32	15	18	64	9	70	72	16	6	31	NA	NA
Transportation	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	3	2	44	31	12	30	13	2	8	NA	NA
Total	**221**	**125**	**197**	**215**	**106**	**172**	**196**	**92**	**48**	**89**	**300**	**674**
U.S. Total	**3,147**	**3,834**	**3,644**	**3,374**	**7,257**	**3,800**	**3,736**	**6,500**	**6,539**	**5,994**	**7,457**	**8,252**
Energy Savings (Thousand MWh)												
Large Utilities[2]												
Residential	868	1,203	1,365	856	990	909	1,055	1,179	1,630	2,194	2,780	2,165
Commercial	1,356	1,583	1,867	1,780	1,502	1,703	2,382	3,537	4,594	4,449	4,557	3,333
Industrial	732	706	1,698	547	475	645	1,059	1,787	1,678	1,325	1,518	1,014
Transportation	12	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	116	376	164	127	104	336	341	320	262	125	151
Total	**2,968**	**3,608**	**5,307**	**3,347**	**3,094**	**3,361**	**4,832**	**6,844**	**8,222**	**8,230**	**8,980**	**6,664**
Small Utilities[3]												
Residential	7	45	5	9	4	8	10	7	9	13	13	14
Commercial	5	148	3	4	3	6	3	3	5	3	4	5
Industrial	1	2	2	1	1	3	8	2	5	1	3	26
Transportation	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	*	3	3	1	1	7	1	2	1	2	3
Total	**13**	**194**	**13**	**17**	**9**	**18**	**28**	**13**	**21**	**18**	**22**	**48**
U.S. Total	**2,981**	**3,802**	**5,318**	**3,364**	**3,103**	**3,379**	**4,860**	**6,857**	**8,243**	**8,248**	**9,002**	**6,712**

[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 1998-2003 and 120 million kilowatthours in 1992-1997.
[3] Refers to electric utilities with sales to ultimate customers or sales for resale less than 150 million kilowatthours in 1998-2003 and 120 million kilowatthours in 1992-1997.
[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.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is "1" and values under 0.5 are shown as "*".)
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, 1992 through 2003
(Thousand megawatthours)

Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Total Energy Savings[1]	**50,265**	**54,075**	**54,762**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**	**45,294**	**35,563**
Energy Efficiency	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720	41,119	31,779
Load Management	2,020	1,790	1,816	875	872	392	953	1,989	2,093	2,763	4,175	4,114

[1] Refers to electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2003 and 120 million kilowatthours in 1992-1997.

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

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

Table 9.7. Demand-Side Management Program Direct and Indirect Costs, 1992 through 2003
(Thousand Dollars)

Item	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Direct Cost[1]	**1,159,540**	**1,420,937**	**1,455,602**	**1,384,232**	**1,250,689**	**1,233,018**	**1,347,245**	**1,623,588**	**2,004,942**	**2,254,059**	**2,289,267**	**NA**
Energy Efficiency	807,403	1,007,323	1,097,504	938,666	820,108	766,384	892,468	1,051,922	1,408,542	1,592,125	1,607,952	NA
Load Management	352,137	413,614	358,098	445,566	430,581	466,634	454,777	571,666	596,400	661,934	681,315	NA
Indirect Cost[2]	**137,670**	**204,600**	**174,684**	**180,669**	**172,955**	**187,902**	**288,775**	**278,609**	**416,342**	**461,598**	**454,266**	**NA**
Total DSM Cost[3]	**1,297,210**	**1,625,537**	**1,630,286**	**1,564,901**	**1,423,644**	**1,420,920**	**1,636,020**	**1,902,197**	**2,421,284**	**2,715,657**	**2,743,533**	**2,348,094**

[1] Reflects electric utility costs incurred during the year that are identified with one of the demand-side program categories.

[2] Reflects costs not directly attributable to specific programs.

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

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

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

Data Quality

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

Unified Data Submission Process

Data are either received on paper forms or entered directly by respondents into CNEAF's Internet Data Collection System (IDC). Hard copy forms are keyed by EIA into the IDC. All data are subject to review via edits built into the IDC, additional quality assurance reports, and review by subject matter experts. Questionable data values are verified through contacts with respondents. Also, survey non-respondents are identified and contacted.

Reliability of Data

Annual survey data have nonsampling errors. Non-sampling errors can be attributed to many sources: (1) inability to obtain complete information about all cases 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; 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 Office of Coal, Nuclear, Electric, and Alternate Fuels (CNEAF) has adopted the following procedures with respect to the revision of data disseminated in energy data products:

- Annual survey data are disseminated either as preliminary or final when first appearing in a data product. Data initially released as preliminary will be so noted in the data product. These data should be released as final by the next dissemination of the same product; however, if final data are available at an earlier interval they may be released in another product.
- All monthly and quarterly survey data are first disseminated as preliminary. These data are revised only after the completion of the 12-month cycle of the data. No revisions are made to the published data before this unless significant errors are discovered that are brought to the attention of the Office Director by the responsible Division Director. In that case, determination as to whether the data should be revised will be made as in item 5 below.
- Weekly and monthly coal production data are first disseminated as estimates. These estimates are revised when quarterly data become available and later finalized when adjusted to conform to final annual production data.
- Any CNEAF data released as preliminary or estimated will be revised, if necessary, and disseminated as final at the same levels of aggregation in a future data product.
- After data are disseminated as final, further revisions will be considered if they make a difference of one percent or greater at the national level. Revisions for differences that do not meet the one percent or greater threshold will be brought to the attention of the Office Director for consideration if the responsible Division Director believes the proposed revision is significant. In either case, the proposed revision will be subject to the EIA revision policy concerning how it affects other EIA products.

- The stages of the data (e.g., preliminary, estimated, final, revised) will be so designated in table/figure titles, headers, or footnotes, or in the accompanying text.
- The magnitudes of changes due to revisions experienced in the past will be included periodically in the data products, so that the reader can assess the accuracy of the data.
- The CNEAF data revision procedures should be referenced in each data product release.

The Electric Power Annual presents the most current annual data available to the EIA. The statistics may differ from those published previously in EIA publications due to corrections, revisions, or other adjustments to the data subsequent to its original release. On a chapter basis, the status (preliminary versus final) of the data contained in the EPA follows:

- **Chapter 1, Generation** Based on data from the Form EIA-906. All data are final.
- **Chapter 2, Capacity** Based on data from the Form EIA-860. All data are final.
- **Chapter 3, Demand, Capacity Resources, and Capacity Margins** Based on data from the Form EIA-411. All data are final.
- **Chapter 4, Fuel** Based on data from the Form EIA-906, EIA-423 and FERC Form 423. All data are final.
- **Chapter 5, Emissions** Based on data from the Form EIA-767 and the Form EIA-906, and on data extracted from the U.S. Environmental protection Agency's Continuous Emission Monitoring System database. The emissions estimates for 2003 are preliminary.
- **Chapter 6, Trade** Based on data from the Form EIA-861 and on import/export data from the National Energy Board of Canada and the Office of Fuels Programs, Fossil Energy, Form FE-781R. All data are final.
- **Chapter 7, Retail Customers, Sales, and Revenues** Based on data on sales, revenue, and average retail price of electricity from the Form EIA-861. All data are final.
- **Chapter 8, Revenue and Expense Statistics** Based on financial data from the Federal Energy Regulatory Commission Form 1, Form EIA-412, and Rural Utility Services Form 7 and Form 12. All data are final.
- **Chapter 9, Demand-Side Management** Based on data on demand-side management from the Form EIA-861. All data are final.

Rounding and Percent Change Calculations

Rounding Rules for Data. 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.

Data Sources For Electric Power Annual

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

- Form EIA-411, "Coordinated Bulk Power Supply Program Report;"
- Form EIA-412, "Annual Electric Industry Financial Report;"
- Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;"
- Form EIA-767, "Steam-Electric Plant Operation and Design Report;"
- Form EIA-860, "Annual Electric Generator Report;"
- Form EIA-861, "Annual Electric Power Industry Report;" and
- Form EIA-906, "Power Plant Report."

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

Each of these forms is summarized below.

Survey data from other Federal sources is also utilized for this publication. They include:

- Fossil Energy Form FE-781R, "Annual Report of International Electric Export/Import Data;" (Department of Energy, Office of Emergency Planning Department of Energy, Office of Fuels Programs);
- Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others;"
- Federal Energy Regulatory Commission Form 423, "Cost and Quality of Fuels for Electric Plants;"
- Rural Utility Services Form 7, "Financial and Statistical Report;" and
- Rural Utility Services Form 12, "Operating Report – Financial."

In addition to the above-named forms, the historical data published in the EPA are compiled from the following sources: Form EIA-759, "Monthly Power Plant Report," Form EIA-860A, "Annual Electric Generator Report–Utility," Form EIA-860B, "Annual Electric Generator Report–Nonutility," and Form EIA-900, "Monthly Nonutility Power Report."

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

Form EIA-411

The Form EIA-411 is filed annually as a voluntary report. The information reported includes: (1) actual energy and peak demand for the preceding year and five additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; and (5) bulk power system maps. The report present various North American Electric Reliability Council (NERC) regional council aggregate totals for their member electric utilities, with some nonmember information included.

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

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

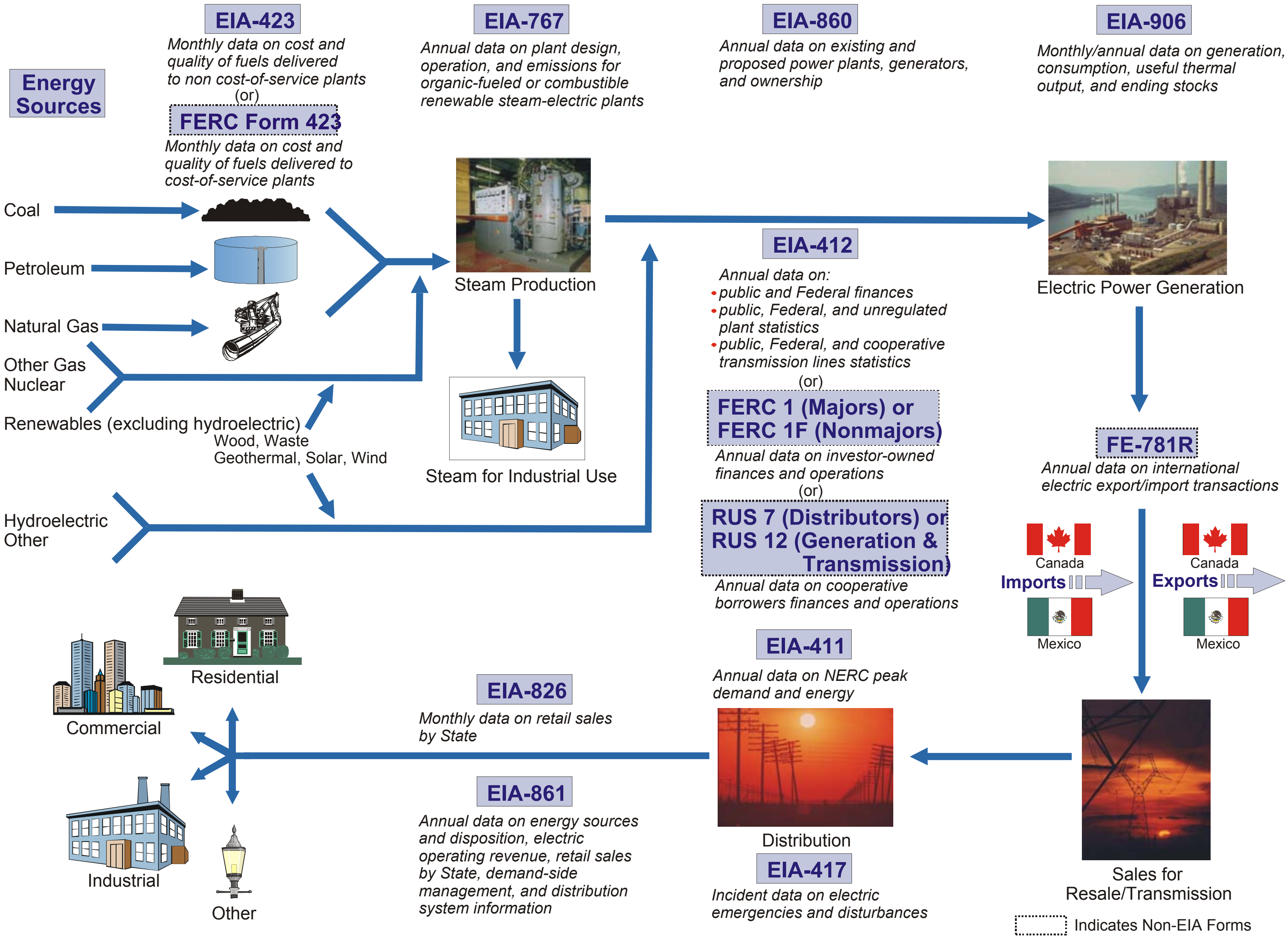
Confidentiality of the Data. Most of the data collected on the Form EIA-411 are not considered confidential. However, plant latitudes and longitudes and tested heat rate data are considered confidential and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information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

Form EIA-412

The Form EIA-412 is a restricted-universe census (no companies that fall below a pre-identified threshold are required to file) used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Those publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had 150,000 megawatthours of sales to ultimate consumers and/or 150,000 megawatthours of sales for resale for the two previous years, as reported on the Form EIA-861, "Annual Electric Utility Report," must submit the Form EIA-412. Beginning with the 2001 data collection, the plant statistics reported on Schedule 9 were also collected from unregulated entities that own plants with a nameplate capacity of 10 megawatts or greater. Also beginning with the 2003 collection, the transmission data reported in Schedules 10 and 11 were collected from each generation and transmission cooperative owning transmission lines having a nominal voltage of 132 kilovolts or greater.

The 1992-1997 data represent those electric utilities meeting a threshold of 120,000 megawatthours for ultimate consumers' sales and or resales. The criteria used to select the respondents for this survey fit approximately 500 publicly owned electric utilities. Federal electric utilities are required to file the Form EIA-412. The financial data for the U.S. Army Corps of Engineers (except for Saint Mary's Falls at Sault Ste. Marie, Michigan); the U.S. Department of Interior, Bureau of Reclamation; and the U.S. International Boundary and Water Commission were collected on the Form EIA-412 from the Federal power marketing administrations.

EIA Electric Industry Data Collection



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

Data Processing and Data System Editing. The Form EIA-412 is made available on EIA's Internet Data Collection system in January to collect data as of the end of the preceding calendar year. The completed surveys are due to EIA on or before April 30. Non-response follow-up procedures are used to attain 100-percent response. Initial edit checks of the data are performed through the EIA's Internet Data Collection System (IDC) by the respondent. Other program edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, are resolved either by the processing office or by further information obtained from a telephone call to the respondent company.

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

Form EIA-423

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

Instrument and Design History. The Form EIA-423 was originally implemented in January 2002 to collect monthly cost and quality data for fossil fuel receipts from owners or operators of nonutility electricity generating plants. Due to the restructuring of the electric power industry, many plants which had historically submitted this information for utility plants on the FERC Form 423 (see subsequent section) were being transferred to the nonutility sector. As a result, a large percentage of fossil fuel receipts were no longer being reported. The Form EIA-423 was implemented to fill this void and to capture the data associated with existing nonregulated power producers. Its design closely follows that of the FERC Form 423. As of the end of 2003, 686 plants were submitting data for this survey.

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

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

Formulas and Methodologies. Data for the Form EIA-423 are collected at the plant level. These data are then used in the following formulas to produce aggregates and averages for each fuel type at the State, Census Division, and U.S. levels. For these formulas, receipts and average heat content are at the plant level. For each geographic region, the summation sign, $\sum$, represents the sum of all facilities in that geographic region.

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

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

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

For fuel receipts (R), the following holds true:

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

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

A_i = average heat content for receipts at facility i;

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

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

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

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

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

A_i average heat content for receipts at facility i;

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

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

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

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

A_i = average heat content for receipts at facility i;

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

Confidentiality of the Data. Plant fuel cost data collected on the survey are considered confidential and will not be made available to the public. State and national level aggregations will be published in this report if sufficient data are available to avoid disclosure of individual company and plant level costs.

FERC Form 423

The Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," is administered by FERC. The data are downloaded from the Commission's website into an EIA database. The Form is due to FERC no later than 45 days after the end of the report month and is filed by approximately 600 regulated plants. To meet the criteria for filing, a plant must have a total steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity of 50 or more megawatts. Only fuel delivered for use in steam-turbine and combined-cycle units is reported. Fuel received for use in gas-turbine or internal-combustion units that is not associated with a combined-cycle operation is not reported.

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

Data Processing and Data System Editing. The FERC processes the data through edits and each month posts a monthly file on their website: http://www.ferc.gov/docs-filing/eforms/form-423/data.asp. The EIA downloads the file and reviews the data for accuracy. Edit checks of the data are performed through computer programs. These edits include both deterministic checks in which records are checked for the presence of data in required fields, and statistical checks in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with other data elements in the file.

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

The associated fuel quality and cost information for each facility was estimated using the State weighted average for the electric power industry for 2003 (FERC Form 423 and Form EIA-423). In the event that no values were available at the State level, national averages for the electric power industry for 2003 were used.

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

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

Form EIA-767

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

Instrument and Design History. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, "Steam-Electric Plant Air and Water Quality Control Data," was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and given the name Form EIA-767, "Steam-Electric Plant Operation and Design Report." In 1986, the respondent universe of 700 was increased to 900 to include plants with nameplate capacity from 10 megawatts to 100 megawatts. Respondents for plants with capacity between 10 and 100 megawatts, complete Schedules 1, 2, 4 (Part A, D, and E), 7 and 8 (Part A and B). Schedule 10, "Footnote," is required where applicable.

Data Processing and Data System Editing. The Form EIA-767 is made available on EIA's Internet Data Collection system in January to collect data as of the end of the preceding calendar year. The completed forms are to be submitted to the EIA by April 30. Equipment design data for each respondent are preprinted from the applicable database. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually reviewed before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process.

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

Form EIA-860

The Form EIA-860 is a mandatory census of all existing and planned electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The survey is used to collect data on existing power plants and 5-year plans for constructing new plants, generating unit additions, modifications, and retirements in existing plants. Data on the survey are collected at the generator unit level.

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

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

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

Data Processing and Data System Editing. The Form EIA-860 data are collected primarily through the IDC. Data are collected for plant status as of January 1 (i.e., for the 2003 data shown in this report, plant status is collected as of January 1, 2004). Edit checks are performed to verify that current data total across and between schedules, are comparable to data reported the previous year, and are consistent with industry norms for comparable facilities. Additional quality assurance reports are run to identify errors. As a result of the editing process, respondents may be contacted to obtain correction or clarification of reported data and to obtain missing data.

In 2003, respondents had 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).

Confidentiality of the Data. The plant latitude and longitude, and tested heat rate data collected on the Form EIA-860 are considered confidential. The data are handled by EIA consistent with EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45 Federal Register (1980) 59812).

Form EIA-861

The Form EIA-861 is a mandatory census of electric power industry participants in the United States. The survey is used to collect information on power production and sales data from approximately 6,000 respondents. About 3,300 are electric utilities, and the remainder are nontraditional entities such as independent power producers or the unregulated subsidiaries of electric utilities and power marketers. The data collected are used to maintain and update the EIA's electric power industry participant frame database.

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

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

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

This assumption proved valid for only about half the eventual transportation respondents. Many respondents continued to report "Other" data as transportation data, delaying the identification of valid transportation reporters. Valid transportation respondents noted their difficulty in reporting data specific to the transportation sector, either because separate rate schedules did not exist, or because transportation information might also include smaller volumes attributable to commercial portions of the transportation customer's operation. In some cases, it was difficult to determine whether a single respondent's data covered the entire mass transit system, or just a portion of it. Rail transit systems in states allowing retail competition could, and did, switch suppliers mid-year. In one instance, a large metro system split its energy procurement between four energy suppliers and two different distribution utilities. Respondents also indicated different methods of determining customer counts.

To address these reporting problems, multiple contacts with respondents were supplemented with calls to cognizant officials at the transit systems identified in the DOT benchmark data. Direct calls to transit systems included several to the metro systems serving Portland, Oregon, San Francisco, Los Angeles, Detroit, Miami, Atlanta, Washington, D.C., New York and Boston. At the time of publication, data was not obtained on only one small urban rail system operating in St. Louis, Missouri.

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

Data Processing and Data System Editing. The Form EIA-861 is made available through the Internet Data Collection System in January of each year to collect data as of the end of the preceding calendar year. The data are edited by respondents when entered into the interactive on-line system. Internal edit checks are performed to verify that current data total across and between schedules, and are comparable to data reported the previous year. Edit checks are also performed to compare data reported on the Form EIA-861 and similar data reported on the Forms EIA-826 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 retail price of electricity represents the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector. State-level weighted average prices per unit of sales are calculated as the ratio of revenue to sales.

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

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

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

Form EIA-906

The Form EIA-906 is used to collect monthly plant-level data on generation, fuel consumption, stocks, 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. The form is also used to collect these statistics from the rest of the frame (i.e., all generators 1 MW or greater) on an annual basis.

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

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

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

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.

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

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

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

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

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

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

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

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

Air Emissions

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

Methodology Overview. 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 submit data annually on this form.

The SO_2 and NO_X air emissions are estimated when possible directly from the continuous emission monitoring system (CEMS) data collected and published by the U.S. Environmental Protection Agency.[1] CEMS coverage is not universal, and when CEMS data is unavailable, emissions of SO_2 and NO_X are estimated using data collected on EIA surveys, particularly the 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 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.

Uncontrolled Emissions. Uncontrolled air pollutant emissions are those emissions that would occur in the absence of any control equipment. Uncontrolled emissions are determined by multiplying the quantity of fuel burned by an emission factor (see Tables A1 and A2 for the CO_2, SO_2, and NO_x emission factors). An emission factor is the average quantity of a pollutant released from a boiler when a unit of fuel is burned.

CO_2 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.

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)[2]. 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.

CO_2 emissions for power producers include emissions 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.

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[3].

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

[1] The Clean Air Act Amendments of 1990 required electric generating units covered under the Acid Rain Program (units 25 megawatts and greater) to be equipped with continuous emission monitoring systems. CEMS is the industry standard for measuring and recording hourly SO_2 and nitrogen oxide (NO_X) emissions.

[2] "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.

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

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 from coal (Table A2) 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 flue gas desulfurization (FGD) units at their coal-fired plants.[4] 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 when CEMS data is unavailable, 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.

Controlled Nitrogen Oxide Emissions. When CEMS data is unavailable, controlled NO_X emissions are calculated by applying the appropriate reduction factor in Table A3. 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 are uncommon, however, and do not significantly affect the results.

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.

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

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	0.05	12.40	138.15
Propane (liquid)	all types	86.5	19.00	139.04
Coal-Oil Mixture	all types	185.00 x S	50.00	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	0.08	1.20	0
Black Liquor	all types	7.00	1.50	0
Chemicals	all types	7.00	1.50	0
Closed Loop Biomass	all types	0.08	1.50	0
Internal	all types	0.08	1.50	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]	Nitrogen Oxides[2]	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	7.00	1.50	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	30.00 x S	11.10	0
RailRoad Ties	all types	0.08	1.50	0
Red Liquor	all types	7.00	1.50	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	7.00	1.50	0
Straw	all types	0.08	1.50	0
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	30.00 x S	11.10	0
Tires	all types	38.00 x S	21.70	0
Waste Byproducts	all types	1.70	2.30	163.29
Waste Coal	all types	38.00 x S	21.70	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	0.50	12.40	0
Methanol	all types	0.50	12.40	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	162.70 x S	67.00	0
Waste Alcohol	all types	0.50	12.40	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	0.00	550.00	0
Landfill Gas	all types	0.60	550.00	115.12
Methane	all types	0.60	550.00	115.11
Other Gas	all types	0.60	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 petroleum coke 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).
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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

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

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

Table A3. Nitrogen Oxide Control Technology Emissions Reduction Factors

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

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

Table A4. Unit-of-Measure Equivalents

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

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and alternate fuels.

Appendix B.
Unregulated Retail Sales – Adjustments to the Data for 2003

The Energy Policy Act of 1992 (EPACT), mandated deregulation of wholesale and retail electricity markets. One important component was to authorize the Federal Energy Regulatory Commission (FERC) to require open access to privately owned transmission systems under its jurisdiction. Another major component permitted States, at their own discretion, to introduce competition in the market for retail sales of electricity. EPACT represented one of the most dramatic changes in the electric power industry in its approximately 100-year history.

In traditional regulated cost-of-service retail markets, all electric services including generation, line maintenance, delivery of power, meter reading and billing are bundled together and provided by a single vertically integrated entity. As of the end of 2003, approximately 20 States have partially deregulated their retail electricity markets. Customers who select alternate energy service providers (ESPs) in those States usually receive electricity and delivery service from different providers, a system often referred to as "unbundled service."

Most States that have implemented retail competition have allowed customers to choose between fully bundled services from their traditional utility, or unbundled electricity service from an ESP. In most cases, when customers elect ESPs for their energy service, their traditional distribution utility (TDU) retains the obligation to deliver the power, maintain distribution lines and related equipment, and bill for all services, including the electricity. However, each State determines the exact extent of competition within its own borders.

Several years ago, in recognition that many consumers were beginning to select unbundled services, the Energy Information Administration (EIA) redesigned the Form EIA-861 ("Annual Electric Power Industry Report") and the Form EIA-826 ("Monthly Sales and Revenue Report With State Distributions") to capture the revenues, volumes, and customer counts for both bundled and unbundled retail electric service. Collecting, processing, and editing this new electric power data in a deregulated environment became a particular challenge for EIA, as ESPs were a new segment of the market and had to be integrated into the surveys. The entry/exit of these ESPs in/out of the markets in each State has been exceedingly difficult for EIA to track. Additionally, EIA is aware that some commercial and industrial customers buy power directly from the grid. Such sales are not currently reported since Independent System Operators and Regional Transmission Operators are not currently respondents to EIA surveys. Thus, those sales are

Table B1. Electricity Volumes Sold and Delivered, Deregulated States, 2003 (Megawatthours)

State	All Sectors, Bundled	All Sectors, ESP	All Sectors, Delivered	MWh Discrepancy	Percent Difference
California	172,746,724	65,179,545	65,963,004	783,459	1.2%
Connecticut	31,230,118	553,201	600,100	46,899	8.5%
District of Columbia	5,725,475	5,154,147	5,220,908	66,761	1.3%
Delaware	10,488,250	1,216,467	2,111,340	894,873	73.6%
Illinois	115,070,513	20,903,116	21,177,378	274,262	1.3%
Massachusetts	45,775,113	8,953,342	9,739,244	785,902	8.8%
Maryland	59,692,937	9,216,004	11,565,646	2,349,642	25.5%
Maine	768,781	9,878,729	11,203,056	1,324,327	13.4%
Michigan	98,765,181	7,830,550	10,112,012	2,281,462	29.1%
Montana	10,282,211	2,409,041	2,542,449	133,408	5.5%
New Hampshire	10,857,646	148,266	114,896	(33,370)	-22.5%
New Jersey	69,874,985	6,714,348	6,507,527	(206,821)	-3.1%
New York	100,387,510	37,628,761	43,834,594	6,205,833	16.5%
Ohio	127,249,081	24,163,225	24,940,157	776,932	3.2%
Pennsylvania	128,596,260	12,405,397	11,772,868	(632,529)	-5.1%
Rhode Island	7,099,519	699,977	697,107	(2,870)	-0.4%
Virginia	101,479,381	30,603	30,350	(253)	-0.8%
Washington	76,112,939	921,003	2,020,562	1,099,559	119.4%
United States	**3,259,247,101**	**214,005,722**	**230,153,198**	**16,147,476**	**7.5%**

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

reported as delivered by TDUs but not captured as a sale by ESPs.

Nonetheless, using Forms EIA-861 and EIA-826, EIA attempts to collect retail sales data from required respondents for all the customers in a State: both fully bundled traditional service customers and customers who selected an ESP for energy service and retained the TDU for delivery service. In order to capture both sides of any unbundled electricity sale, sales and revenue data must be collected separately from the ESP and the TDUs for those customers who switched to unbundled services.

For the reasons noted above, reported volumes of these unbundled sales (and therefore, associated revenues and customer counts) often do not match at an aggregate level in some States. Additionally, there are a number of instances in which, while the aggregate State sales and deliveries match fairly well, respondent ESPs and TDUs have each classified the sale/delivery to a different end use sector; i.e., residential, commercial, industrial, transportation. Table B1 reports bundled and unbundled sales and delivery activity in the 18 States with retail competition as reported on the Form EIA-861 in 2003.

Investigations by EIA staff, as well as verification from State Public Utility Commissions (PUCs), indicate that data for delivered power reported by the delivery utilities is probably more reliable than the corresponding transactions reported by the ESPs. Thus, as a consequence of these data issues, the EIA has adjusted the unbundled sales volumes and revenues reported by ESPs in the seven States with the most significant discrepancies in reporting. These adjustments were calculated at an end use sector level to also correct for misclassified sales. However, EIA continues to make available all respondent data in separate data files. Eleven of the 18 States show sufficient agreement between reported unbundled sales and delivery, either because the discrepancy in sales volume is small in percentage terms, or the actual volume is relatively small. However, seven States--California, Delaware, Maine, Maryland, Michigan, New York, and Washington--show either significant percentage differences between reported sales and deliveries or large volume differences. The purpose of the adjustments is to equate retail sales to deliveries where ESP and delivery utilities reported disparate information.

Specifically, in the seven States we have adjusted, total sales were adjusted to the sum of bundled sales and delivery volumes, rather than the sum of bundled sales and reported sales by ESPs. Total state adjusted sales volumes were also apportioned to the end-use sectors where discrepancies were evident.

Total revenues were adjusted by the average prices reported by end-use sector by State, so that average prices would not be impacted by our adjustment. The total sales adjustment nationally came to just under 15 billion kilowatthours, or 0.4 percent of all reported retail sales. Even in the 18 States with unbundled sales activity, most electricity sales are still provided through bundled service, and in the Nation, 93 percent of all retail sales are fully bundled.

The following paragraphs describe data adjustment measures taken by EIA in the seven States where divergence of the revenue and energy data reported by energy-only and delivery-only entities were disparate The adjustments were made only after extensive contacts with respondents and/or verification from independent sources such as State Public Utility Commissions.

California

Deregulated retail sales activity in California remains largely from old contracts that date from 2000 and prior years. Differences for all sectors for total ESP sales compared with total TDU deliveries for 2003 are small at 1.2 percent, or a total of 783 million kilowatthours (Table B2). However, distribution utility and ESP consumer sector classification differences result in significant differences at the sector level, especially between the commercial and industrial sectors. In the commercial sector, ESPs reported sales that exceeded reported deliveries by about 6,163 million kWh; conversely, in the industrial sector, unbundled respondents reported a discrepancy of similar magnitude but with deliveries well in excess of sales. The estimation of delivery volumes resulted in a negligible change in residential sales, a reduction in commercial sales, and higher industrial sales. Commercial revenues were reduced by the average reported unbundled power price multiplied by the volume adjustment ($437 million) and industrial revenue was raised ($526 million). The resulting classification of sales by end-use sector in California better matches historical consumption trends by end-use sector. These adjustments result in a negligible increase to all reported sales in California.

Table B2. Adjusted California Sales and Revenue, 2003

Sector	Sales (million kWh)			Revenue (thousand dollars)		
	All Providers	Adjustment	Final Sales	All Providers	Adjustment	Final Revenue
Residential	80,782	(83)	80,699	9,693,221	(6,818)	9,686,403
Commercial	114,211	(6,163)	108,049	13,603,712	(436,540)	13,167,172
Industrial	42,130	7,023	49,153	4,314,224	526,087	4,840,311
Transportation	802	6	809	47,292	230	47,522
All Sectors	**237,925**	**783**	**238,710**	**27,658,449**	**82,959**	**27,741,408**

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

Table B3. Adjusted New York Sales and Revenue, 2003

Sector	Sales (million kWh)			Revenue (thousand dollars)		
	All Providers	Adjustment	Final Sales	All Providers	Adjustment	Final Revenue
Residential	46,769	347	47,116	6,714,917	27,695	6,742,612
Commercial	70,364	2,132	72,496	9,233,223	175,315	9,408,538
Industrial	18,017	3,727	21,744	1,403,375	148,885	1,552,260
Transportation	2,867	0	2,867	228,428	4,211	232,639
All Sectors	**138,017**	**6,206**	**144,222**	**17,579,943**	**356,106**	**17,936,049**

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

Table B4. Adjusted Maine Sales and Revenue, 2003

Sector	Sales (million kWh)			Revenue (thousand dollars)		
	All Providers	Adjustment	Final Sales	All Providers	Adjustment	Final Revenue
Residential	4,596	(377)	4,219	540,781	(18,880)	521,901
Commercial	4,778	(819)	3,959	453,083	(43,644)	409,439
Industrial	1,274	2,520	3,794	127,727	113,165	240,892
Transportation	-	-	-	-	-	-
All Sectors	**10,648**	**1,324**	**11,972**	**1,121,591**	**50,642**	**1,172,232**

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

Table B5. Adjusted Maryland Sales and Revenue, 2003

Sector	Sales (million kWh)			Revenue (thousand dollars)		
	All Providers	Adjustment	Final Sales	All Providers	Adjustment	Final Revenue
Residential	26,812	(140)	26,672	2,067,141	(6,658)	2,060,483
Commercial	20,812	(3,862)	16,950	1,340,546	(162,736)	1,177,810
Industrial	20,824	6,352	27,176	1,032,308	296,548	1,328,856
Transportation	461	-	461	26,659	-	26,659
All Sectors	**68,909**	**2,350**	**71,259**	**4,466,654**	**127,154**	**4,593,808**

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

New York

New York shows the largest single-State discrepancy between ESP sales and TDU deliveries for all sectors, with TDUs reporting 6,206 million kilowatthours more than ESPs (Table B1). One factor causing this difference may relate to a State program in New York that allows large retail commercial and industrial consumers (1 megawatt or greater) to purchase power directly from the New York Independent System Operator (ISO) realizing a lower energy rate than that offered by their traditional utilities. However, the program requires the customer's local utility to deliver the power. Consequently, the utilities continue to report their deliveries to EIA, but since the ISO is not a respondent, the power sales are not reported to EIA. Table B3 reports adjustments to the various end-use sectors in New York, with total sales adjustments coming to 6,206 million kilowatthours. This net adjustment to sales represents about 6 percent of all reported sales in New York.

Maine

The Maine PUC required utilities in Maine under its jurisdiction to withdraw entirely from the energy portion of retail service and concentrate on delivery services exclusively. The exceptions to providing delivery-only service are related to special bundled-service contracts that are being allowed to terminate on schedule. The shortfall for ESP power volumes, as indicated by distribution utility delivery data, and verified by the Maine PUC, is approximately 13 percent of all deliveries (Table B1), and is thought to be related to a single large power marketer's failure to report their sales in Maine. The effect of using delivery volumes in Maine in place of ESP volumes is to slightly reduce residential and commercial sales, while raising industrial sales substantially (Table B4). Total net sales increments of 1,324 million kilowatthours represent 12 percent of all reported sales in Maine.

Maryland

Adjustments in Maryland resulted in slightly less residential sales, substantially less commercial sales, substantially more industrial sales, and no change in the transportation sector (Table B5). As with California, differing customer classifications between power vendors and delivery utilities contributed greatly to the discrepancies. The commercial sector was adjusted downward by 3,862 million kilowatthours while the industrial sector was raised by 6,352 million kilowatthours. Moreover, electric power marketers responded to a request for proposals issued in 2002 to place the State government's electricity requirements under a single omnibus agreement. Separating transit system consumption from other components proved more difficult for electric

Table B6. Adjusted Delaware Sales and Revenue, 2003

	Sales (million kWh)			Revenue (thousand dollars)		
Sector	**All Providers**	**Adjustment**	**Final Sales**	**All Providers**	**Adjustment**	**Final Revenue**
Residential	4,190	-	4,190	360,046	-	360,046
Commercial	4,286	(400)	3,886	300,289	(16,041)	284,248
Industrial	3,228	1,295	4,523	175,650	57,094	232,744
Transportation	-	-	-	-	-	-
All Sectors	**11,704**	**895**	**12,600**	**835,985**	**41,053**	**877,038**

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

Table B7. Adjusted Michigan Sales and Revenue, 2003

	Sales (million kWh)			Revenue (thousand dollars)		
Sector	**All Providers**	**Adjustment**	**Final Sales**	**All Providers**	**Adjustment**	**Final Revenue**
Residential	33,770	(101)	33,669	2,818,906	(5,829)	2,813,077
Commercial	39,360	(3,968)	35,392	2,877,233	(205,704)	2,671,529
Industrial	33,462	6,351	39,813	1,694,499	281,445	1,975,944
Transportation	3	-	3	279	-	279
All Sectors	**106,595**	**2,282**	**108,877**	**7,390,917**	**69,912**	**7,460,829**

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

Table B8. Adjusted Washington Sales and Revenue, 2003

	Sales (million kWh)			Revenue (thousand dollars)		
Sector	**All Providers**	**Adjustment**	**Final Sales**	**All Providers**	**Adjustment**	**Final Revenue**
Residential	31,872	-	31,872	2,010,273	-	2,010,273
Commercial	27,981	58	28,039	1,696,316	4,950	1,701,266
Industrial	17,139	1,041	18,180	777,991	88,195	866,186
Transportation	42	-	42	2,716	-	2,716
All Sectors	**77,034**	**1,099**	**78,134**	**4,487,296**	**93,145**	**4,580,441**

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

service providers. Total net adjustments in Maryland of 2,350 million kilowatthours increased all reported sales in the State by 3 percent.

Delaware

In Delaware, only one delivery utility is in operation, and discussions with the utility verified the delivery volumes. No adjustments were needed for the residential sector, but a downward revision in the commercial sector, and a significant upward revision in the industrial sector were necessary. These adjustments resulted in a net volume change of about 895 million kilowatthours in the State (Table B6), a large percent of reported ESP sales (73 percent, Table B1), but only about 8 percent of all reported sales in Delaware.

Michigan

Adjustments in Michigan result in slightly less residential sector sales, a downward adjustment in the commercial sector, and an upward adjustment in the industrial sector. The adjustments in Michigan result in a net increase of 2 percent of all reported sales in Michigan.

Washington

In Washington, as in New York, large customers could avail themselves of purchasing options that could result in substantial dollar savings for their electric power needs. Purchases out of the Mid-Columbia River Dams (Mid-C) power pool were not reported as an energy-only sale because the Mid-C does not file a Form EIA-861 or EIA-826 survey. However, these sales were verified by the Washington Utilities and Transmission Commission, and reported as delivered by Puget Sound Energy. Adjustments reflecting these missing sales volumes result in no change in the residential sector, slightly more commercial sales, a much larger upward adjustment in the industrial sector and no change to the transportation sector. The total sales adjustment of 1,099 million kilowatthours represents about 1 percent of all reported sales in Washington.

Glossary

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