Chapter 9

Section 9.2

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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.

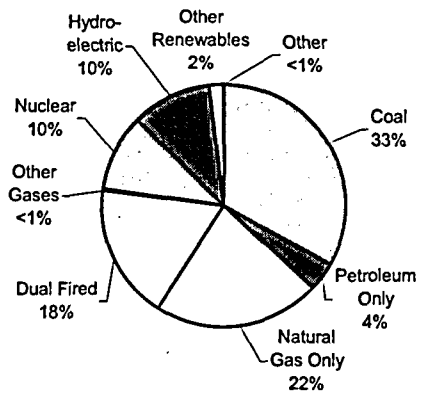
Capacity

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.

[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.

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

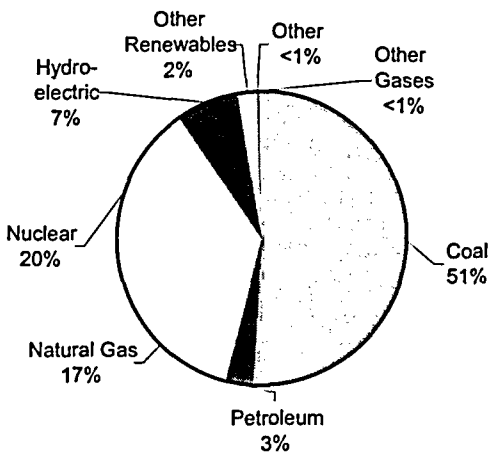
On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, 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.

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."

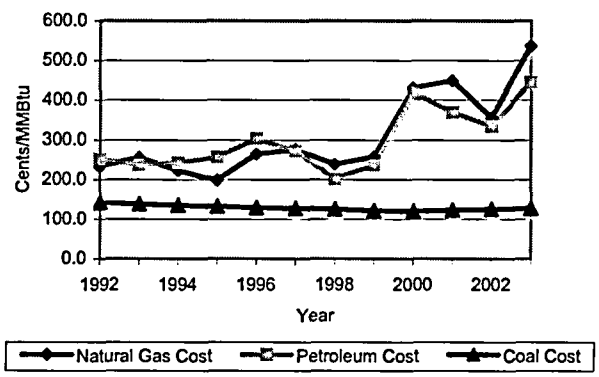
Fuel

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."

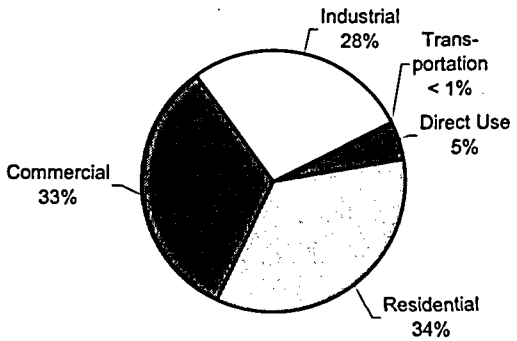
Trade

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

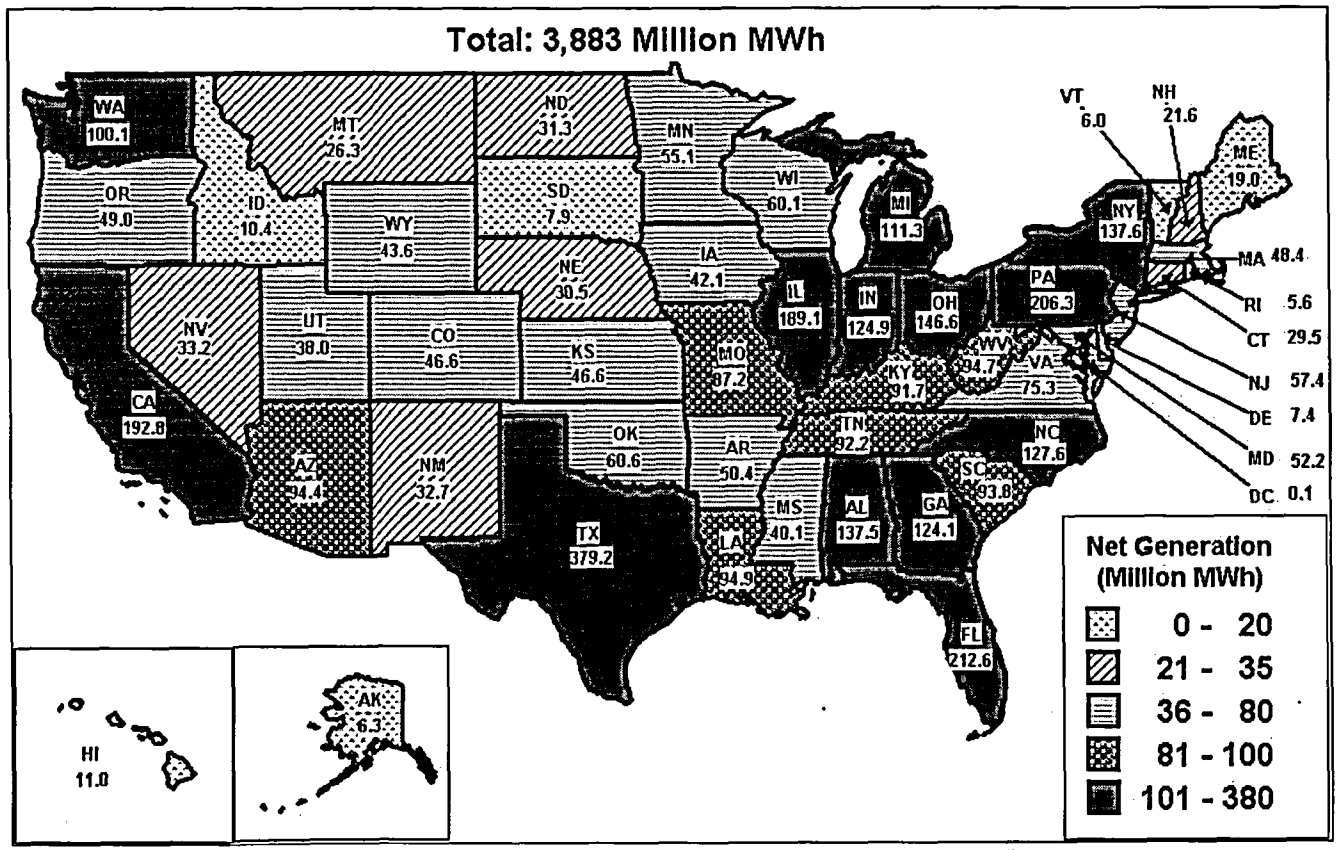
Table 1.1. Net Generation by Energy Source by Type of Producer, 1992 through 2003
(Thousand Megawatthours)

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)

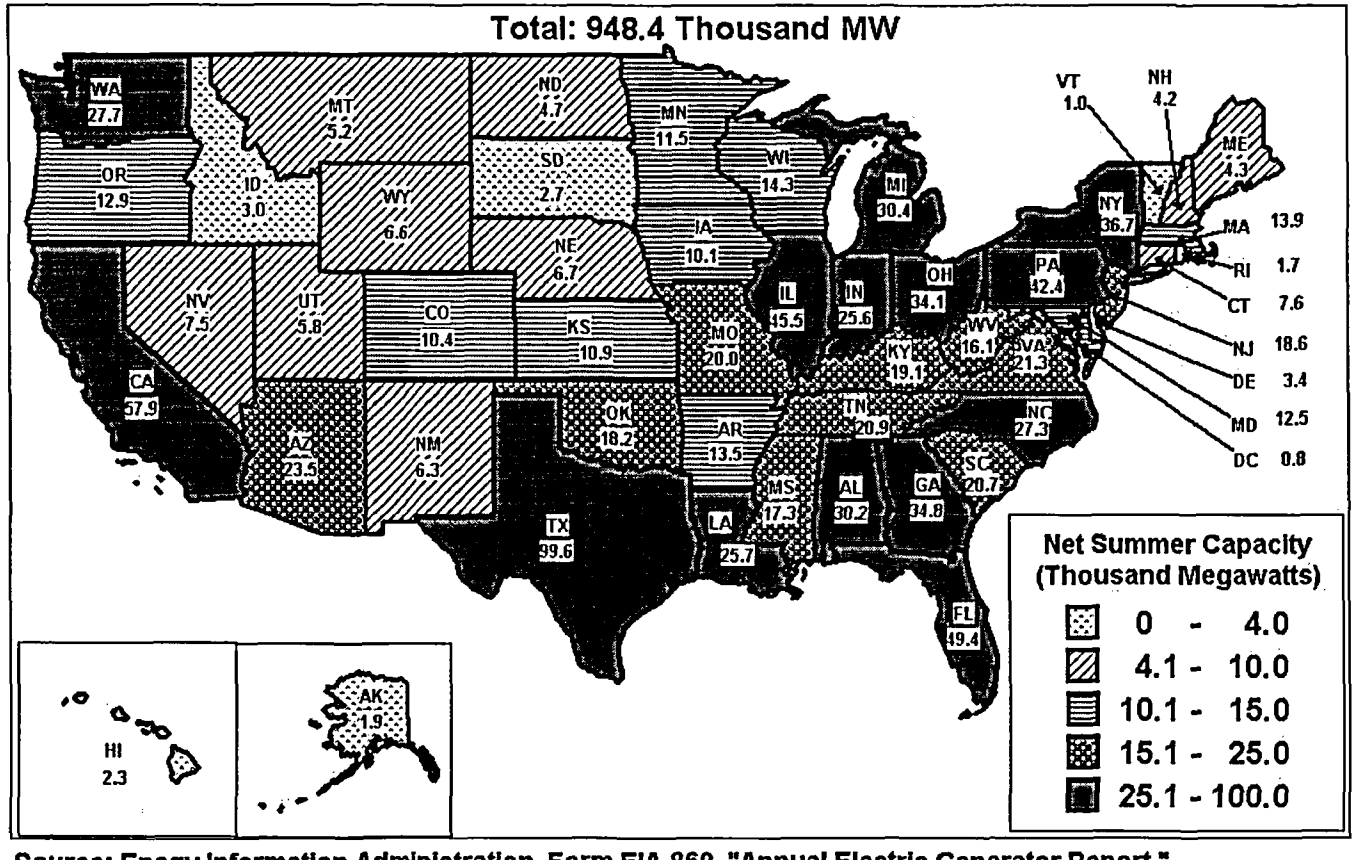
Period	Coal[1]	Petroleum[2]	Natural Gas	Dual Fired	Other Gases[3]	Nuclear	Hydro-electric[4]	Other Renewables[5]	Other[6]	Total
Total (All Sectors)										
1992	309,372	45,642	60,736	118,913	2,069	98,985	95,962	14,281	545	746,507
1993	310,148	44,019	65,523	120,157	1,931	99,041	98,557	14,656	550	754,582
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 Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	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	2000	2001	2002	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	2005	2006	2007	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[3]	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.

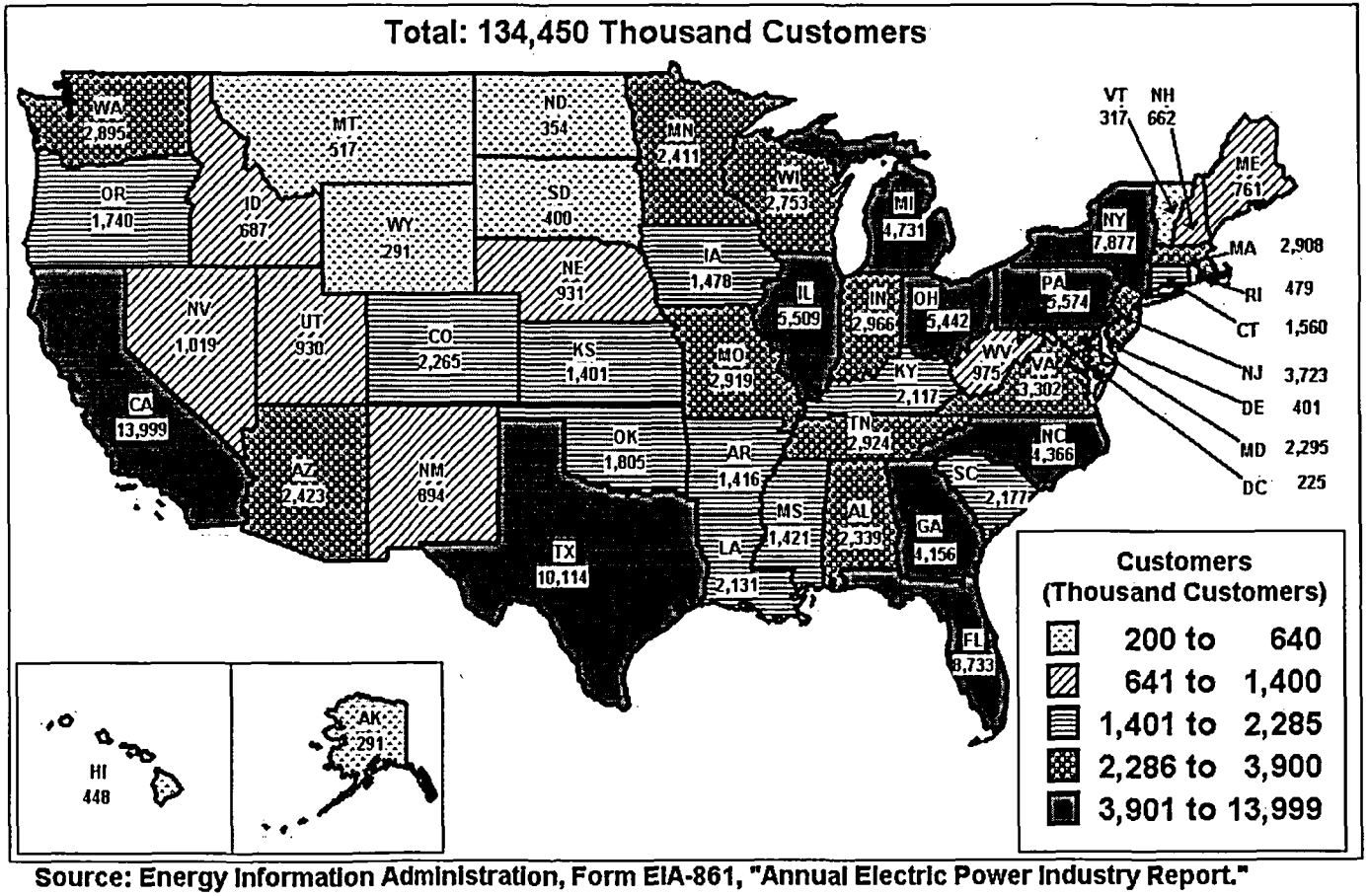
[3] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."

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."

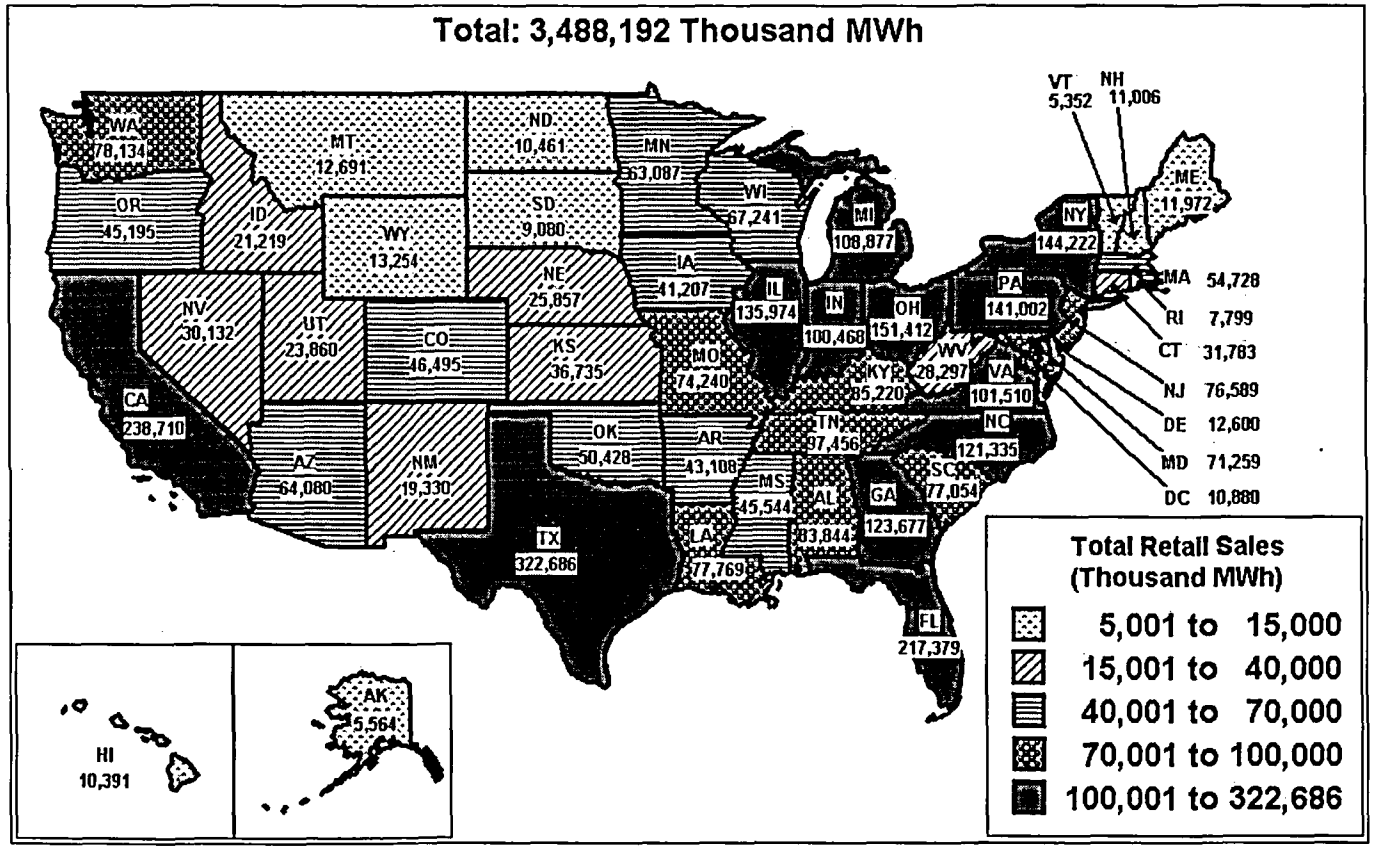
NA = Not available.

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."

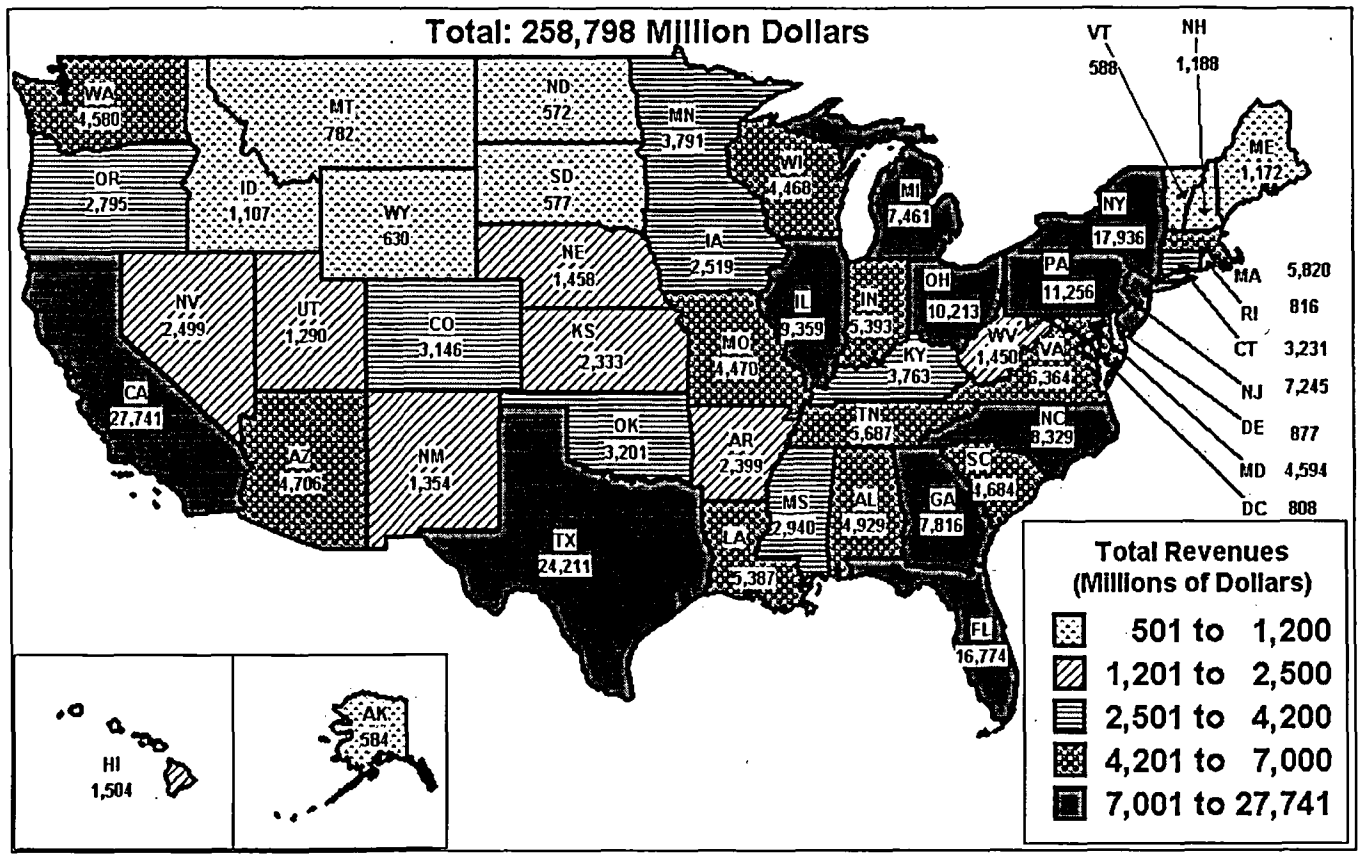
[4] From 1996 to 1999, revenue estimated based on retail sales reported on the Form EIA-861.

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

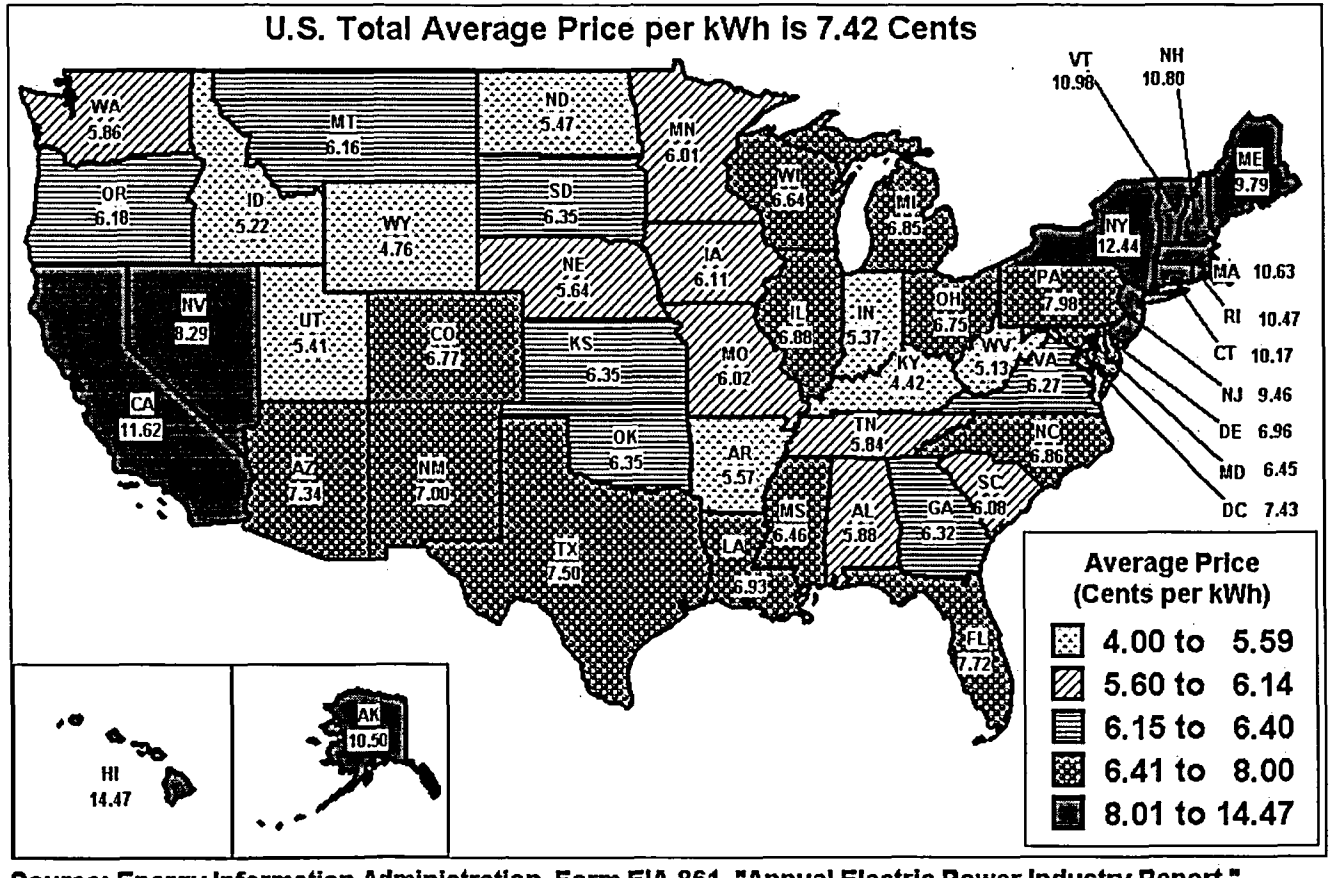
[1] Beginning in 2003 the Other Sector has been eliminated. Data previously assigned to the Other Sector have been reclassified as follows: Lighting for public buildings, streets, and highways, interdepartamental sales, and other sales to public authorities are now included in the Commercial Sector; 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.

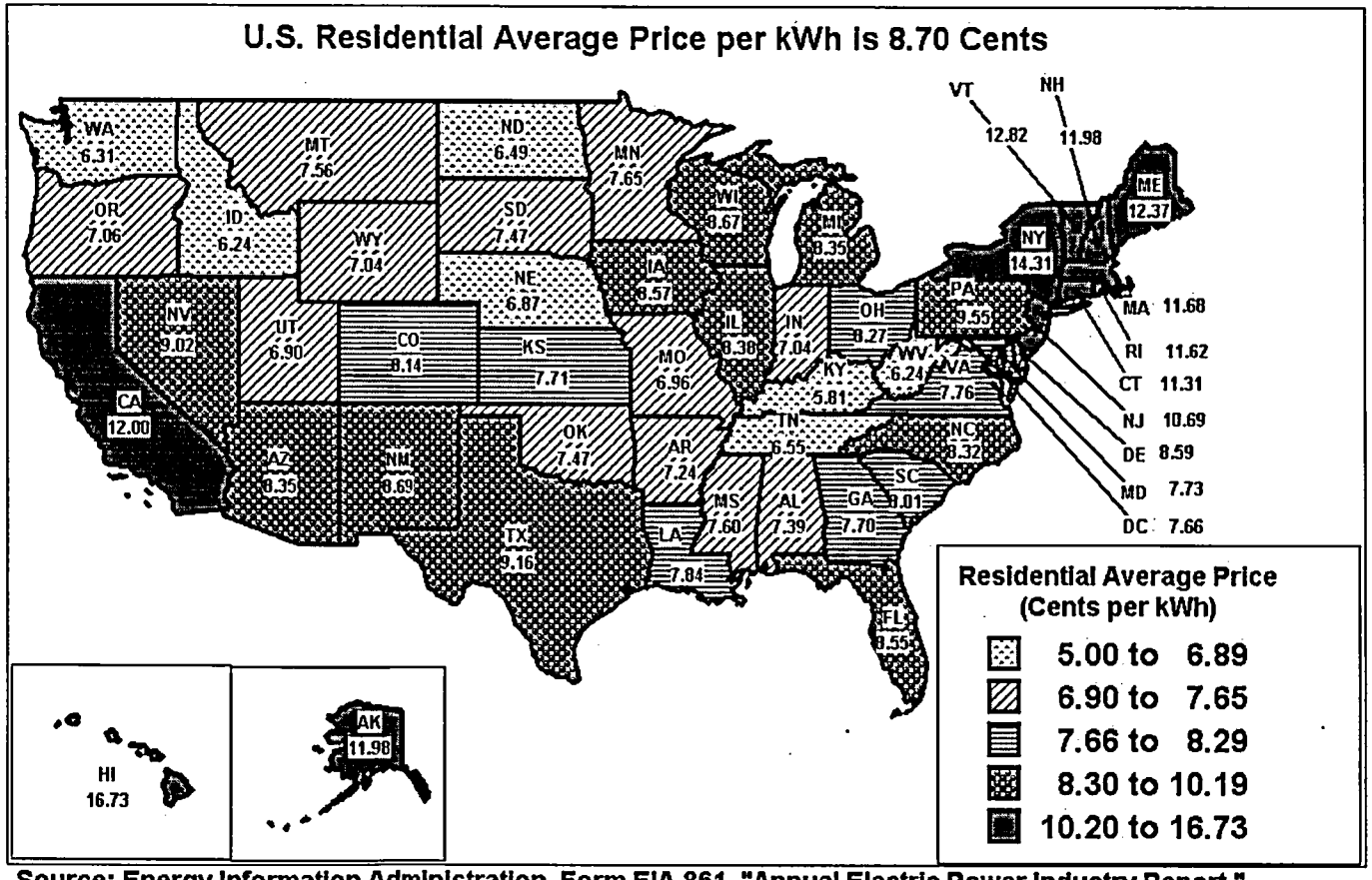
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

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



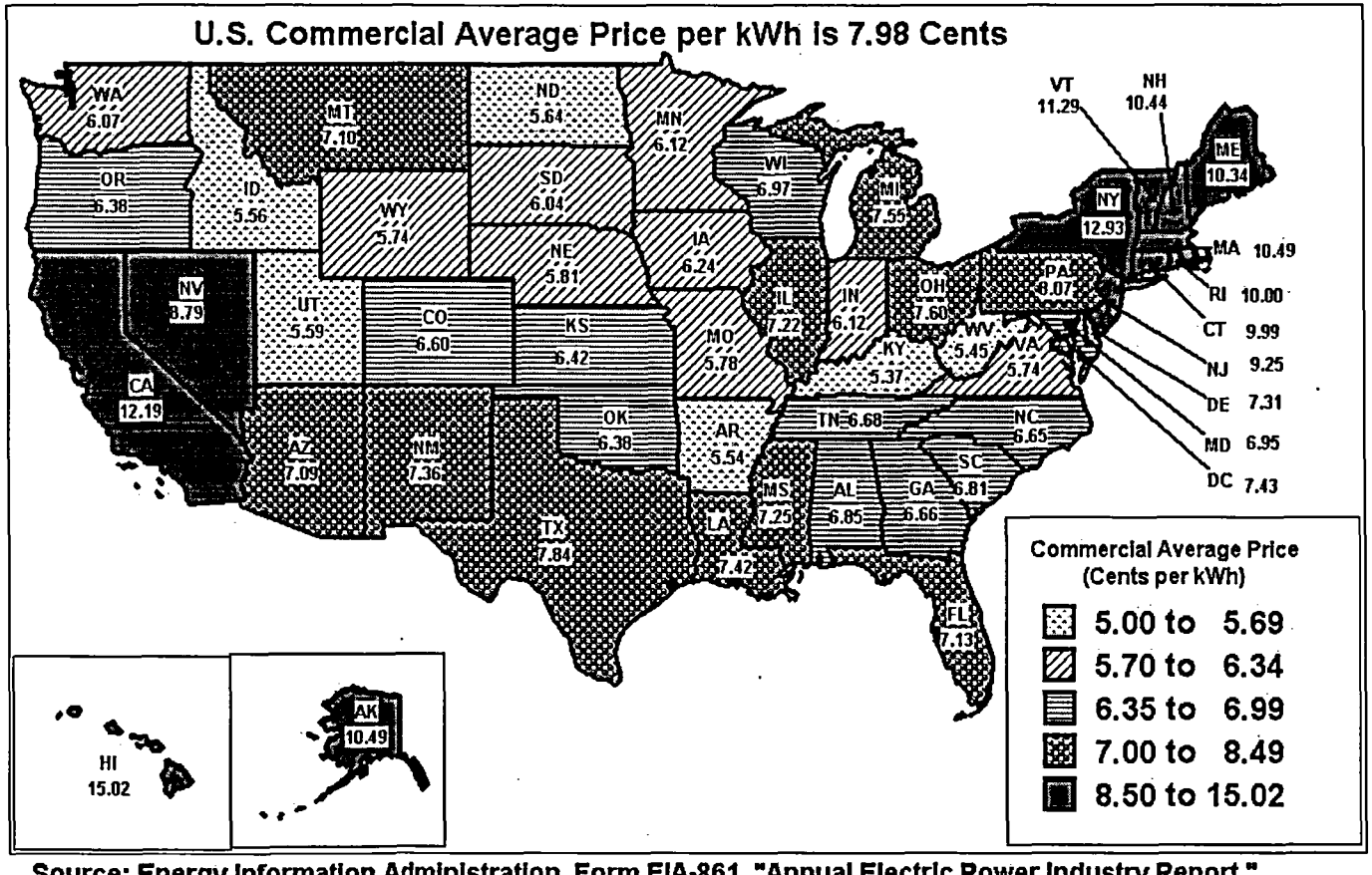
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

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



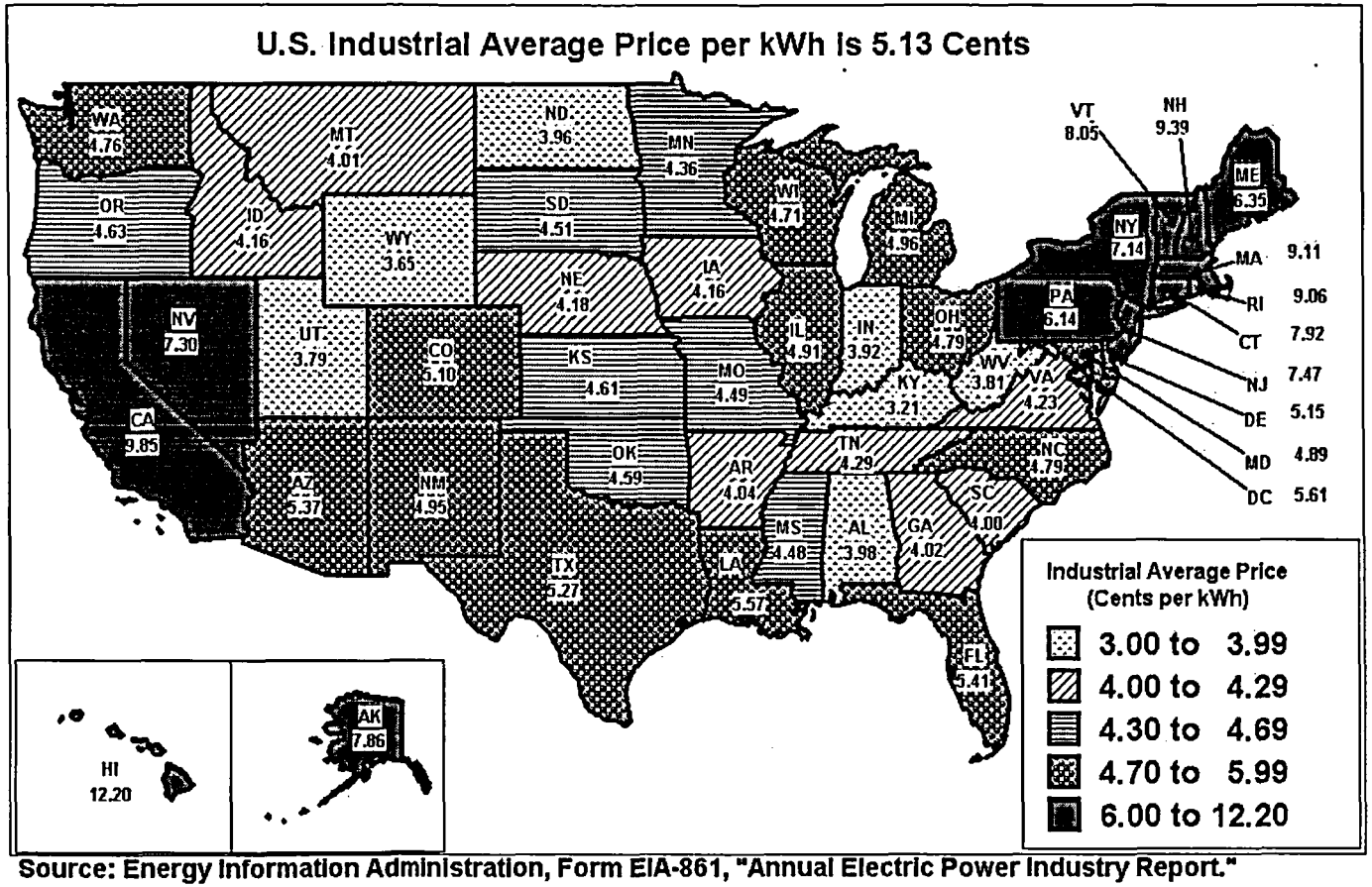
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

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

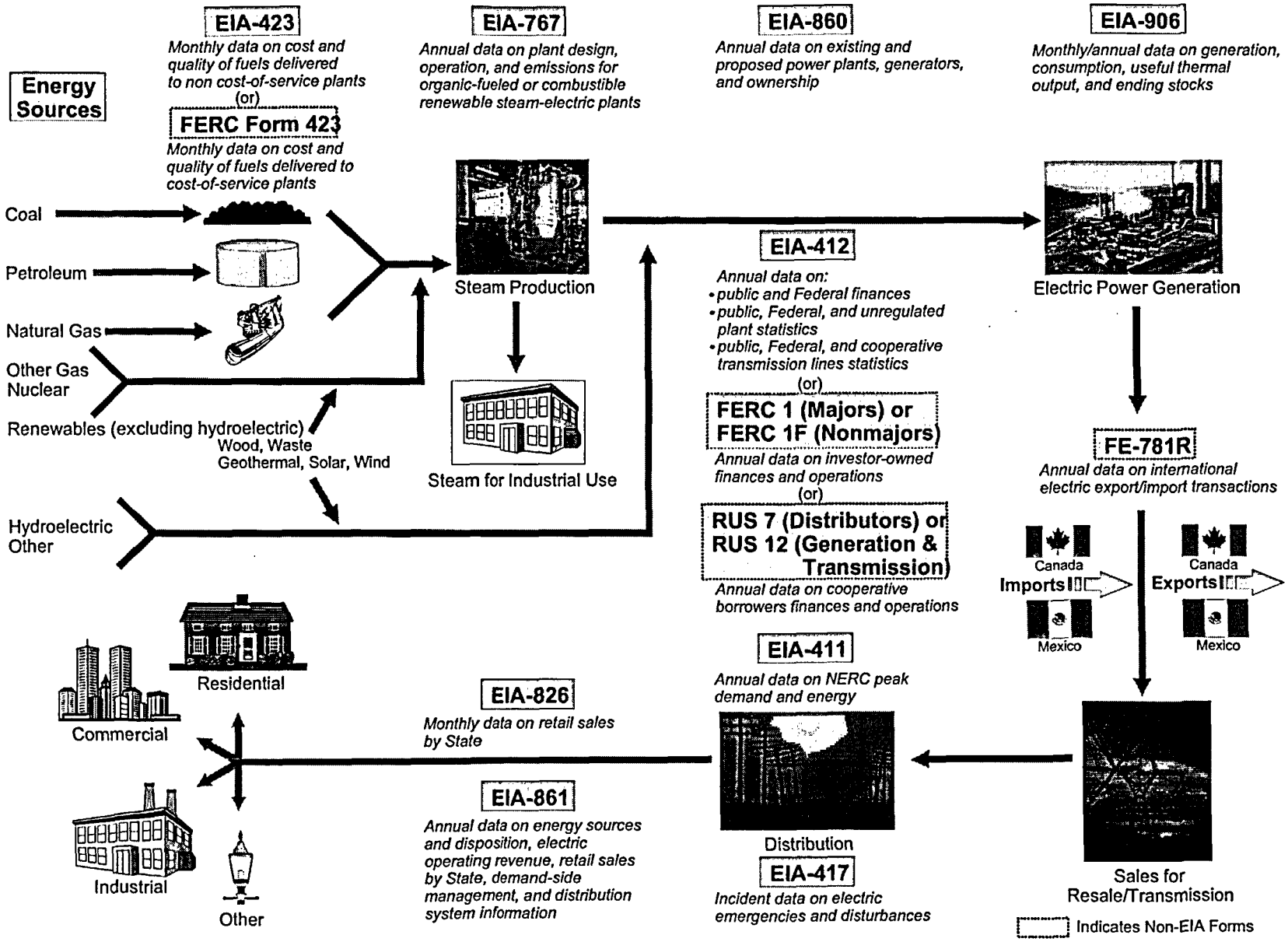
Confidentiality of the Data. Most of the data collected on the Form EIA-411 are not considered confidential. However, plant latitudes and longitudes and tested heat rate data are considered confidential and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information 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:

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

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

A_i = average heat content for receipts at facility i;

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

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

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

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

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

A_i average heat content for receipts at facility i;

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

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

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

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

A_i = average heat content for receipts at facility i;

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

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

	Sales (million kWh)			Revenue (thousand dollars)		
Sector	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

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Quality

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Preface

The State Electricity Profiles 2002 presents a summary of State statistics. The objective of the publication is to provide industry decisionmakers, government policymakers, analysts, and the general public with historical data that may be used in understanding U.S. electricity markets. The State Electricity Profiles is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy.

Data in this report can be used in analytic studies 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 State Electricity Profiles presents a summary of the key State statistics for the reporting year contrasted with 2 prior years within the past 10 years. The tables present summary statistics; ten largest plants by generating capacity; top five utilities ranked by retail sales; electric power industry generating capacity by primary energy source; electric power industry generation of electricity by primary energy source; utility delivered fuel prices for coal, petroleum, and natural gas; electric power emissions estimates; retail sales, revenue, and average revenue per kilowatthour by sector; and utility retail sales statistics. Monetary values in this publication are expressed in nominal terms.

Data published in the State Electricity Profiles are compiled from five forms filed annually by electric utilities and deregulated electric power producers.

Data Sources

Table 1
Form EIA-767, "Steam-Electric Plant Operation and Design Report"
Form EIA-860, "Annual Electric Generation Report"
Form EIA-861, "Annual Electric Power Industry Report"
Form EIA-906, "Power Plant Report"

Table 2
Form EIA-860, "Annual Electric Generation Report"

Table 3
Form EIA-861, "Annual Electric Power Industry Report"

Table 4
Form EIA-860, "Annual Electric Generation Report"

Table 5
Form EIA-906, "Power Plant Report"

Table 6
FERC Form 423, "Cost and Quality of Fuels for Electric Plants"
Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"

Table 7
Form EIA-767, "Steam-Electric Plant Operation and Design Report"
Form EIA-906, "Power Plant Report"

Table 8
Form EIA-861, "Annual Electric Power Industry Report"

Table 9
Form EIA-861, "Annual Electric Power Industry Report"

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Alabama		
NERC Region(s)		SERC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	26,586	12
Electric Utilities	23,429	8
Independent Power Producers & Combined Heat and Power	3,157	23
Net Generation (megawatthours)	132,920,670	8
Electric Utilities	123,739,223	4
Independent Power Producers & Combined Heat and Power	9,181,447	22
Emissions (thousand short tons)		
Sulfur Dioxide	467	10
Nitrogen Oxide	178	9
Carbon Dioxide	83,993	9
Sulfur Dioxide/sq. mile	9	13
Nitrogen Oxide/sq. mile	3	13
Carbon Dioxide/sq. mile	1,655	15
Utility and ESP Retail Electricity Sales (megawatthours)	83,067,078	15
Utility Retail Electricity Sales (megawatthours)	83,067,078	15
Direct Use (megawatthours)	5,866,005	7
Average Retail Price (cents/kWh)	5.71	41

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Alabama			
1. Browns Ferry	Nuclear	Tennessee Valley Authority	3,291
2. James H Miller Jr	Petroleum, Gas, Coal	Alabama Power Co	2,686
3. Barry	Petroleum, Gas, Coal	Alabama Power Co	2,520
4. E C Gaston	Petroleum, Coal	Alabama Power Co	1,906
5. Joseph M Farley	Nuclear	Alabama Power Co	1,675
6. Widows Creek	Petroleum, Coal	Tennessee Valley Authority	1,608
7. Colbert	Gas, Petroleum, Coal	Tennessee Valley Authority	1,565
8. Gorgas	Petroleum, Coal	Alabama Power Co	1,288
9. Greene County	Petroleum, Gas, Coal	Alabama Power Co	1,257
10. Tenaska Lindsay Hill	Petroleum, Gas	Tenaska Alabama Partners LP	858

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Alabama					
A. Alabama Power Company	52,073,190	17,402,645	13,356,972	21,108,226	205,347
B. Tennessee Valley Authority	5,073,906	0	0	5,035,798	38,108
C. City of Huntsville	4,729,117	2,147,576	1,515,221	1,035,464	30,856
D. Decatur Utilities	1,440,271	378,010	298,700	755,537	8,024
E. City of Florence	1,168,312	624,194	390,433	142,259	11,426
Total	64,484,796	20,552,425	15,561,326	28,077,284	293,761
Percentage of Utility Sales	77.6	68.5	79.1	86.1	38.4

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Alabama							
Coal	11,579	11,286	11,246	–0.3	55.7	51.5	42.3
Petroleum	18	16	34	7.5	.1	.1	.1
Natural Gas	92	347	2,605	44.9	.4	1.6	9.8
Dual Fired	494	1,359	1,577	13.8	2.4	6.2	5.9
Nuclear	4,835	4,873	4,966	.3	23.2	22.2	18.7
Hydroelectric	2,955	2,959	3,002	.2	14.2	13.5	11.3
Total Electric Utilities	**19,972**	**20,840**	**23,429**	**1.8**	**96.0**	**95.1**	**88.1**
Coal	23	23	19	–2.3	.1	.1	.1
Petroleum	*	4	7	53.7	.0	.0	.0
Natural Gas	126	155	1,820	34.6	.6	.7	6.8
Other Gases	94	104	4	–30.0	.5	.5	.0
Dual Fired	0	61	765	NM	.0	.3	2.9
Other Renewables	583	723	543	–.8	2.8	3.3	2.0
Total IPP's & Combined Heat and Power	**826**	**1,070**	**3,157**	**16.1**	**4.0**	**4.9**	**11.9**
Coal	11,602	11,309	11,265	–.3	55.8	51.6	42.4
Petroleum	18	20	41	9.7	.1	.1	.2
Natural Gas	218	502	4,425	39.7	1.0	2.3	16.6
Other Gases	94	104	4	–30.0	.5	.5	.0
Dual Fired	494	1,420	2,342	18.9	2.4	6.5	8.8
Nuclear	4,835	4,873	4,966	.3	23.2	22.2	18.7
Hydroelectric	2,955	2,959	3,002	.2	14.2	13.5	11.3
Other Renewables	583	723	543	–.8	2.8	3.3	2.0
Total Electric Industry	**20,798**	**21,910**	**26,586**	**2.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Alabama							
Coal	66,758,044	71,586,318	71,630,811	0.8	67.2	59.9	53.9
Petroleum	72,217	118,818	184,379	11.0	.1	.1	.1
Natural Gas	435,761	885,184	11,242,320	43.5	.4	.7	8.5
Nuclear	17,823,325	29,572,670	31,856,926	6.7	17.9	24.7	24.0
Hydroelectric	9,034,210	11,520,637	8,824,787	–.3	9.1	9.6	6.6
Total Electric Utilities	**94,123,557**	**113,683,627**	**123,739,223**	**3.1**	**94.8**	**95.1**	**93.1**
Coal	578,277	517,000	410,853	–3.7	.6	.4	.3
Petroleum	120,727	118,597	127,669	.6	.1	.1	.1
Natural Gas	825,217	1,224,434	4,661,745	21.2	.8	1.0	3.5
Other Gases	338,105	283,878	112,541	–11.5	.3	.2	.1
Other Renewables	3,351,114	3,344,408	3,750,350	1.3	3.4	2.8	2.8
Other	0	370,388	118,289	NM	.0	.3	.1
Total IPP's & Combined Heat and Power	**5,213,440**	**5,858,704**	**9,181,447**	**6.5**	**5.2**	**4.9**	**6.9**
Coal	67,336,321	72,103,318	72,041,664	.8	67.8	60.3	54.2
Petroleum	192,944	237,415	312,048	5.5	.2	.2	.2
Natural Gas	1,260,978	2,109,618	15,904,065	32.5	1.3	1.8	12.0
Other Gases	338,105	283,878	112,541	–11.5	.3	.2	.1
Nuclear	17,823,325	29,572,670	31,856,926	6.7	17.9	24.7	24.0
Hydroelectric	9,034,210	11,520,637	8,824,787	–.3	9.1	9.6	6.6
Other Renewables	3,351,114	3,344,408	3,750,350	1.3	3.4	2.8	2.8
Other	0	370,388	118,289	NM	.0	.3	.1
Total Electric Industry	**99,336,997**	**119,542,331**	**132,920,670**	**3.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Alabama				
Coal (2002 cents per million Btu)	196.2	157.8	141.6	–3.5
Average heat value (Btu per pound)	12,092	11,584	11,245	–.8
Average sulfur Content(percent)	1.3	1.1	.9	–3.8
Petroleum (2002 cents per million Btu)	474.2	416.5	509.2	.8
Average heat value (Btu per gallon)	137,673	139,646	140,117	.2
Average sulfur Content(percent)	.0	.0	.1	NM
Gas (2002 cents per million Btu)	290.3	284.9	345.7	1.9
Average heat value (Btu per cubic foot)	1,016	1,031	1,027	.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Alabama				
Sulfur Dioxide				
Coal	555	575	454	-2.2
Petroleum	*	1	1	15.6
Gas	*	*	*	.0
Other	9	9	12	3.5
Total	565	585	467	-2.1
Nitrogen Oxide				
Coal	238	212	163	-4.2
Petroleum	*	*	*	-.5
Gas	12	12	10	-2.0
Other	2	3	5	7.7
Total	253	227	178	-3.9
Carbon Dioxide				
Coal	68,530	73,459	75,716	1.1
Petroleum	194	245	258	3.2
Gas	1,225	1,882	8,019	23.2
Total	69,949	75,585	83,993	2.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Alabama							
Retail Sales (thousand megawatthours)							
Residential	22,628	24,893	30,022	3.2	34.8	33.4	36.1
Commercial	11,254	16,397	19,666	6.4	17.3	22.0	23.7
Industrial	30,524	32,617	32,615	.7	46.9	43.8	39.3
Other	652	646	764	1.8	1.0	.9	.9
Total	65,058	74,554	83,067	2.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,720	1,725	2,138	2.4	41.9	42.3	45.1
Commercial	869	1,069	1,305	4.6	21.2	26.2	27.5
Industrial	1,475	1,242	1,244	-1.9	35.9	30.4	26.2
Other	43	43	57	3.3	1.0	1.0	1.2
Total	4,108	4,080	4,745	1.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.60	6.93	7.12	-.7	NA	NA	NA
Commercial	7.72	6.52	6.63	-1.7	NA	NA	NA
Industrial	4.83	3.81	3.82	-2.6	NA	NA	NA
Other	6.56	6.65	7.46	1.4	NA	NA	NA
Total	6.31	5.47	5.71	-1.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Alabama						
Number of Entities	1	36	1	25	0	63
Number of Retail Customers	1,349,662	473,625	22	493,920	0	2,317,229
Retail Sales (thousand megawatthours)	52,073	15,552	5,074	10,368	0	83,067
Percentage of Retail Sales	62.69	18.72	6.11	12.48	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	2,951	908	161	725	0	4,745
Percentage of Revenue	62.20	19.13	3.39	15.28	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.67	5.84	3.17	6.99	0	5.71

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Alaska		
NERC Region(s)		–
Primary Energy Source		Gas
Net Summer Capability (megawatts)	2,006	48
Electric Utilities	1,740	40
Independent Power Producers & Combined Heat and Power	267	45
Net Generation (megawatthours)	6,767,325	48
Electric Utilities	5,471,990	42
Independent Power Producers & Combined Heat and Power	1,295,335	43
Emissions (thousand short tons)		
Sulfur Dioxide	4	48
Nitrogen Oxide	11	43
Carbon Dioxide	4,205	46
Sulfur Dioxide/sq. mile	0	50
Nitrogen Oxide/sq. mile	0	51
Carbon Dioxide/sq. mile	7	50
Utility and ESP Retail Electricity Sales (megawatthours)	5,465,489	51
Utility Retail Electricity Sales (megawatthours)	5,465,489	50
Direct Use (megawatthours)	1,022,952	25
Average Retail Price (cents/kWh)	10.46	7

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Alaska			
1. Beluga	Gas	Chugach Electric Assn Inc	338
2. George M Sullivan Gen	Petroleum, Gas	Municipality of Anchorage	220
3. Bradley Lake	Hydro	Alaska Electric G & T Coop Inc	126
4. North Pole	Petroleum	Golden Valley Elec Assn Inc	96
5. Anchorage 1	Petroleum, Gas	Municipality of Anchorage	79
6. Snettisham	Hydro	Alaska Electric Light&Power Co	78
7. Central Production Fa	Gas	Phillips Alaska Inc	64
8. Bernice Lake	Gas	Chugach Electric Assn Inc	62
9. Lemon Creek	Petroleum	Alaska Electric Light&Power Co	58
10. Eklutna Hydro Project	Hydro	Municipality of Anchorage	44

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Alaska					
A. Chugach Electric Assn, Inc	1,141,106	534,869	560,934	40,577	4,726
B. Golden Valley Elec Assn, Inc	1,069,320	289,559	128,372	651,389	0
C. Anchorage Mun Light and Power	892,174	148,174	726,683	0	17,317
D. Matanuska Electric Assn, Inc	546,601	340,664	205,210	0	727
E. Homer Electric Assn, Inc	486,921	156,912	164,344	164,511	1,154
Total	4,136,122	1,470,178	1,785,543	856,477	23,924
Percentage of Utility Sales	76	76	80	79	12

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Alaska							
Coal	54	54	25	-8.1	2.7	2.6	1.2
Petroleum	501	537	522	.5	25.2	26.5	26.0
Natural Gas	497	489	526	.6	25.0	24.1	26.2
Dual Fired	308	308	270	-1.4	15.5	15.2	13.5
Hydroelectric	352	362	396	1.3	17.7	17.9	19.7
Other Renewables	*	*	0	NM	.0	.0	.0
Total Electric Utilities	**1,711**	**1,750**	**1,740**	**.2**	**86.0**	**86.3**	**86.7**
Coal	57	57	60	.7	2.8	2.8	3.0
Petroleum	63	83	55	-1.6	3.2	4.1	2.7
Natural Gas	100	101	151	4.7	5.0	5.0	7.5
Dual Fired	37	37	*	-41.5	1.9	1.8	.0
Other Renewables	21	0	0	NM	1.1	.0	.0
Total IPP's & Combined Heat and Power	**278**	**278**	**267**	**-.5**	**14.0**	**13.7**	**13.3**
Coal	110	110	85	-2.8	5.5	5.4	4.2
Petroleum	564	620	577	.3	28.4	30.6	28.8
Natural Gas	596	590	677	1.4	30.0	29.1	33.8
Dual Fired	345	345	271	-2.7	17.4	17.0	13.5
Hydroelectric	352	362	396	1.3	17.7	17.9	19.7
Other Renewables	21	*	0	NM	1.1	.0	.0
Total Electric Industry	**1,989**	**2,028**	**2,006**	**.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Alaska							
Coal	322,564	237,165	204,490	-4.9	5.6	3.9	3.0
Petroleum	458,542	740,721	875,153	7.4	8.0	12.0	12.9
Natural Gas	2,496,949	3,031,164	2,952,996	1.9	43.6	49.2	43.6
Hydroelectric	1,302,992	1,098,953	1,439,351	1.1	22.8	17.9	21.3
Total Electric Utilities	**4,581,047**	**5,108,003**	**5,471,990**	**2.0**	**80.1**	**83.0**	**80.9**
Coal	210,559	205,537	370,798	6.5	3.7	3.3	5.5
Petroleum	128,882	117,167	87,216	-4.2	2.3	1.9	1.3
Natural Gas	694,865	676,570	825,166	1.9	12.1	11.0	12.2
Other Renewables	105,926	47,569	12,155	-21.4	1.9	.8	.2
Total IPP's & Combined Heat and Power	**1,140,231**	**1,046,843**	**1,295,335**	**1.4**	**19.9**	**17.0**	**19.1**
Coal	533,123	442,702	575,288	.8	9.3	7.2	8.5
Petroleum	587,424	857,888	962,369	5.6	10.3	13.9	14.2
Natural Gas	3,191,814	3,707,734	3,778,162	1.9	55.8	60.2	55.8
Hydroelectric	1,302,992	1,098,953	1,439,351	1.1	22.8	17.9	21.3
Other Renewables	105,926	47,569	12,155	-21.4	1.9	.8	.2
Total Electric Industry	**5,721,278**	**6,154,846**	**6,767,325**	**1.9**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Alaska				
Average heat value (Btu per pound)	0	0	7,946	NM
Average heat value (Btu per gallon)	0	0	144,536	NM
Gas (2002 cents per million Btu)	139.7	178.8	227.1	5.5
Average heat value (Btu per cubic foot)	999	1,000	1,018	.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Alaska				
Sulfur Dioxide				
Coal	3	7	4	0.9
Petroleum	*	*	*	-6.4
Gas	0	0	0	NM
Other	*	*	0	NM
Total	4	7	4	.1
Nitrogen Oxide				
Coal	4	4	4	.2
Petroleum	*	1	1	10.7
Gas	5	6	6	1.0
Other	*	*	0	NM
Total	10	10	11	1.2
Carbon Dioxide				
Coal	862	897	890	.4
Petroleum	526	794	895	6.1
Gas	2,200	2,540	2,420	1.1
Total	3,588	4,231	4,205	1.8

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Alaska							
Retail Sales (thousand megawatthours)							
Residential	1,629	1,726	1,932	1.9	37.2	35.6	35.3
Commercial	2,062	2,181	2,238	.9	47.1	45.0	40.9
Industrial	501	756	1,088	9.0	11.4	15.6	19.9
Other	182	178	207	1.4	4.2	3.7	3.8
Total	4,375	4,841	5,465	2.5	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	202	203	233	1.6	41.0	40.5	40.7
Commercial	219	213	227	.4	44.5	42.5	39.7
Industrial	46	58	83	6.9	9.3	11.6	14.5
Other	26	27	29	1.3	5.3	5.4	5.1
Total	493	501	572	1.7	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	12.42	11.76	12.05	–.3	NA	NA	NA
Commercial	10.64	9.77	10.13	–.5	NA	NA	NA
Industrial	9.13	7.69	7.65	–1.9	NA	NA	NA
Other	14.22	15.16	14.04	–.1	NA	NA	NA
Total	11.28	10.35	10.46	–.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Alaska						
Number of Entities	21	34	0	18	0	73
Number of Retail Customers	26,592	56,307	0	201,922	0	284,821
Retail Sales (thousand megawatthours)	455	1,379	0	3,632	0	5,465
Percentage of Retail Sales	8.32	25.23	.00	66.45	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	59	136	0	378	0	572
Percentage of Revenue	10.26	23.71	.00	66.03	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	12.90	9.84	.00	10.40	0	10.46

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Arizona		
NERC Region(s)		WSCC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	19,442	19
Electric Utilities	15,699	15
Independent Power Producers & Combined Heat and Power	3,743	19
Net Generation (megawatthours)	94,131,666	18
Electric Utilities	81,710,063	12
Independent Power Producers & Combined Heat and Power	12,421,603	19
Emissions (thousand short tons)		
Sulfur Dioxide	72	31
Nitrogen Oxide	88	25
Carbon Dioxide	49,298	19
Sulfur Dioxide/sq. mile	1	38
Nitrogen Oxide/sq. mile	1	38
Carbon Dioxide/sq. mile	434	38
Utility and ESP Retail Electricity Sales (megawatthours)	62,600,737	23
Utility Retail Electricity Sales (megawatthours)	62,600,737	22
Direct Use (megawatthours)	12,093	41
Average Retail Price (cents/kWh)	7.21	16

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Arizona			
1. Palo Verde	Nuclear	Arizona Public Service Co	3,733
2. Navajo	Petroleum, Coal	Salt River Proj Ag I & P Dist	2,250
3. Glen Canyon Dam	Hydro	U S Bureau of Reclamation	1,296
4. Hoover Dam	Hydro	U S Bureau of Reclamation	1,040
5. Cholla	Gas, Petroleum, Coal	Arizona Public Service Co	995
6. Redhawk	Gas	Pinnacle West Energy	918
7. Springerville	Petroleum, Coal	Tucson Electric Power Co	800
8. Coronado	Petroleum, Coal	Salt River Proj Ag I & P Dist	785
9. Agua Fria	Petroleum, Other, Gas	Salt River Proj Ag I & P Dist	626
10. Desert Basin	Gas	Reliant Energy Desert Basin LP	598

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Arizona					
A. Arizona Public Service Company	23,361,755	10,443,820	10,589,065	2,224,922	103,948
B. Salt River Project	22,783,685	10,440,416	8,358,335	3,139,132	845,802
C. Tucson Electric Power Company	8,012,420	3,188,728	1,609,366	2,956,685	257,641
D. Morenci Water & Electric Co	1,575,877	10,021	13,637	1,552,219	0
E. Citizens Communications Co	1,323,612	639,559	387,074	77,407	219,572
Total	57,057,349	24,722,544	20,957,477	9,950,365	1,426,963
Percentage of Utility Sales	91	94	94	90	51

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Arizona							
Coal	5,108	5,256	5,336	0.5	33.7	34.3	27.4
Petroleum	97	85	108	1.2	.6	.6	.6
Natural Gas	233	107	539	9.8	1.5	.7	2.8
Dual Fired	3,006	3,045	3,060	.2	19.9	19.9	15.7
Nuclear	3,810	3,778	3,733	–.2	25.2	24.7	19.2
Hydroelectric	2,781	2,893	2,919	.5	18.4	18.9	15.0
Other Renewables	0	*	5	NM	.0	.0	.0
Total Electric Utilities	**15,034**	**15,164**	**15,699**	**.5**	**99.3**	**99.0**	**80.7**
Coal	51	51	68	3.3	.3	.3	.3
Petroleum	5	5	4	–3.6	.0	.0	.0
Natural Gas	2	56	3,658	137.4	.0	.4	18.8
Dual Fired	48	45	13	–13.3	.3	.3	.1
Total IPP's & Combined Heat and Power	**105**	**157**	**3,743**	**48.7**	**.7**	**1.0**	**19.3**
Coal	5,159	5,307	5,404	.5	34.1	34.6	27.8
Petroleum	102	90	112	1.0	.7	.6	.6
Natural Gas	235	163	4,198	37.8	1.5	1.1	21.6
Dual Fired	3,054	3,090	3,073	.1	20.2	20.2	15.8
Nuclear	3,810	3,778	3,733	–.2	25.2	24.7	19.2
Hydroelectric	2,781	2,893	2,919	.5	18.4	18.9	15.0
Other Renewables	0	*	5	NM	.0	.0	.0
Total Electric Industry	**15,140**	**15,321**	**19,442**	**2.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Arizona							
Coal	37,020,817	34,219,281	37,957,468	0.3	54.1	43.4	40.3
Petroleum	59,875	60,927	51,061	–1.8	.1	.1	.1
Natural Gas	1,872,396	2,064,599	5,238,416	12.1	2.7	2.6	5.6
Nuclear	22,048,880	29,314,200	30,861,911	3.8	32.2	37.2	32.8
Hydroelectric	7,023,071	12,401,491	7,551,144	.8	10.3	15.7	8.0
Other Renewables	0	0	50,063	NM	.0	.0	.1
Total Electric Utilities	**68,025,039**	**78,060,498**	**81,710,063**	**2.1**	**99.4**	**99.0**	**86.8**
Coal	251,378	259,567	269,163	.8	.4	.3	.3
Petroleum	25,568	4,754	6,385	–14.3	.0	.0	.0
Natural Gas	64,153	419,212	12,054,599	78.9	.1	.5	12.8
Other Renewables	102,849	81,170	91,456	–1.3	.2	.1	.1
Total IPP's & Combined Heat and Power	**443,947**	**764,703**	**12,421,603**	**44.8**	**.6**	**1.0**	**13.2**
Coal	37,272,195	34,478,848	38,226,631	.3	54.4	43.7	40.6
Petroleum	85,443	65,681	57,446	–4.3	.1	.1	.1
Natural Gas	1,936,549	2,483,811	17,293,015	27.5	2.8	3.2	18.4
Nuclear	22,048,880	29,314,200	30,861,911	3.8	32.2	37.2	32.8
Hydroelectric	7,023,071	12,401,491	7,551,144	.8	10.3	15.7	8.0
Other Renewables	102,849	81,170	141,519	3.6	.2	.1	.2
Total Electric Industry	**68,468,986**	**78,825,201**	**94,131,666**	**3.6**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Arizona				
Coal (2002 cents per million Btu)	150.8	146.4	125.8	-2.0
Average heat value (Btu per pound)	10,271	10,159	10,151	-.1
Average sulfur Content(percent)	.5	.5	.6	2.2
Petroleum (2002 cents per million Btu)	570.1	546.6	653.5	1.5
Average heat value (Btu per gallon)	140,535	140,337	138,007	-.2
Average sulfur Content(percent)	.0	.0	.1	NM
Gas (2002 cents per million Btu)	312.9	302.6	320.1	.3
Average heat value (Btu per cubic foot)	1,027	1,014	1,018	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Arizona				
Sulfur Dioxide				
Coal	132	134	71	-6.6
Petroleum	*	*	*	-24.6
Gas	0	0	*	NM
Other	*	*	0	NM
Total	133	135	72	-6.6
Nitrogen Oxide				
Coal	128	79	82	-4.9
Petroleum	*	*	0	NM
Gas	3	3	6	8.6
Other	*	*	*	-16.6
Total	131	82	88	-4.4
Carbon Dioxide				
Coal	38,857	36,953	40,624	.5
Petroleum	73	58	51	-3.8
Gas	1,266	1,591	8,623	23.8
Total	40,196	38,601	49,298	2.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Arizona							
Retail Sales (thousand megawatthours)							
Residential	16,705	20,683	26,413	5.2	37.6	38.0	42.2
Commercial	14,813	17,788	22,371	4.7	33.4	32.7	35.7
Industrial	10,989	13,253	11,026	*	24.8	24.3	17.6
Other	1,901	2,732	2,791	4.4	4.3	5.0	4.5
Total	44,408	54,456	62,601	3.9	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,795	1,874	2,185	2.2	44.2	45.4	48.4
Commercial	1,435	1,432	1,629	1.4	35.3	34.7	36.1
Industrial	710	688	573	−2.3	17.5	16.6	12.7
Other	119	136	127	.7	2.9	3.3	2.8
Total	4,060	4,130	4,514	1.2	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	10.75	9.06	8.27	−2.9	NA	NA	NA
Commercial	9.69	8.05	7.28	−3.1	NA	NA	NA
Industrial	6.46	5.19	5.20	−2.4	NA	NA	NA
Other	6.28	4.98	4.56	−3.5	NA	NA	NA
Total	9.14	7.58	7.21	−2.6	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Arizona						
Number of Entities	5	27	3	10	0	45
Number of Retail Customers	1,336,955	848,059	20,146	146,603	0	2,351,763
Retail Sales (thousand megawatthours)	34,286	24,927	1,274	2,114	0	62,601
Percentage of Retail Sales	54.77	39.82	2.04	3.38	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	2,690	1,602	40	182	0	4,514
Percentage of Revenue	59.59	35.49	.89	4.03	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.85	6.43	3.16	8.60	0	7.21

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Arkansas		
NERC Region(s)		SPP/SERC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	11,300	29
Electric Utilities	9,550	25
Independent Power Producers & Combined Heat and Power	1,750	31
Net Generation (megawatthours)	47,611,644	27
Electric Utilities	42,873,364	24
Independent Power Producers & Combined Heat and Power	4,738,280	31
Emissions (thousand short tons)		
Sulfur Dioxide	80	29
Nitrogen Oxide	45	35
Carbon Dioxide	29,057	32
Sulfur Dioxide/sq. mile	2	32
Nitrogen Oxide/sq. mile	1	37
Carbon Dioxide/sq. mile	558	30
Utility and ESP Retail Electricity Sales (megawatthours)	42,449,558	30
Utility Retail Electricity Sales (megawatthours)	42,449,558	30
Direct Use (megawatthours)	2,131,036	18
Average Retail Price (cents/kWh)	5.61	42

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Arkansas			
1. Arkansas Nuclear One	Nuclear	Entergy Arkansas Inc	1,776
2. Independence	Petroleum, Coal	Entergy Arkansas Inc	1,657
3. White Bluff	Petroleum, Coal	Entergy Arkansas Inc	1,620
4. Robert E Ritchie	Gas	Entergy Arkansas Inc	878
5. Lake Catherine	Gas	Entergy Arkansas Inc	688
6. Hot Spring Energy Fac	Gas	Duke Energy Hot Spring LLC	652
7. Wrightsville Power Fa	Other, Gas	Wrightsville Power Fac LLC	568
8. Flint Creek	Petroleum, Coal	Southwestern Electric Power Co	480
9. Bull Shoals	Hydro	USCE-Little Rock District	391
10. Pine Bluff Energy Cen	Gas	Pine Bluff Energy LLC	198

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Arkansas					
A. Entergy Arkansas, Inc	19,599,834	7,049,328	5,221,073	7,074,241	255,192
B. Southwestern Electric Power Co	3,840,092	987,231	940,205	1,815,812	96,844
C. Mississippi Cnty Elec Coop Inc	3,031,672	56,098	18,476	2,955,389	1,709
D. Oklahoma Gas & Electric Co	2,587,316	684,492	705,086	1,079,651	118,087
E. First Electric Coop Corp	1,446,264	946,362	178,054	264,297	57,551
Total	30,505,178	9,723,511	7,062,894	13,189,390	529,383
Percentage of Utility Sales	72	63	76	78	72

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Arkansas							
Coal	3,817	3,865	3,757	−0.2	37.8	38.3	33.2
Petroleum	204	206	18	−23.8	2.0	2.0	.2
Natural Gas	67	14	199	12.9	.7	.1	1.8
Dual Fired	2,564	2,582	2,386	−.8	25.4	25.6	21.1
Nuclear	1,694	1,694	1,776	.5	16.8	16.8	15.7
Hydroelectric	1,326	1,327	1,415	.7	13.1	13.2	12.5
Total Electric Utilities	**9,672**	**9,688**	**9,551**	**−.1**	**95.7**	**96.1**	**84.5**
Petroleum	3	3	0	NM	.0	.0	.0
Natural Gas	58	21	1,292	41.3	.6	.2	11.4
Dual Fired	35	35	156	18.1	.3	.3	1.4
Hydroelectric	1	1	1	−2.7	.0	.0	.0
Other Renewables	335	335	301	−1.2	3.3	3.3	2.7
Total IPP's & Combined Heat and Power	**432**	**395**	**1,750**	**16.8**	**4.3**	**3.9**	**15.5**
Coal	3,817	3,865	3,757	−.2	37.8	38.3	33.2
Petroleum	207	209	18	−23.9	2.0	2.1	.2
Natural Gas	124	35	1,490	31.8	1.2	.3	13.2
Dual Fired	2,599	2,617	2,542	−.2	25.7	26.0	22.5
Nuclear	1,694	1,694	1,776	.5	16.8	16.8	15.7
Hydroelectric	1,327	1,328	1,416	.7	13.1	13.2	12.5
Other Renewables	335	335	301	−1.2	3.3	3.3	2.7
Total Electric Industry	**10,104**	**10,083**	**11,300**	**1.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Arkansas							
Coal	18,025,615	22,760,970	22,986,650	2.7	44.5	50.4	48.3
Petroleum	65,624	66,622	136,134	8.4	.2	.1	.3
Natural Gas	1,928,399	2,242,628	1,755,867	−1.0	4.8	5.0	3.7
Nuclear	13,521,676	14,208,157	14,558,884	.8	33.4	31.4	30.6
Hydroelectric	4,507,758	3,511,260	3,435,829	−3.0	11.1	7.8	7.2
Total Electric Utilities	**38,049,072**	**42,789,637**	**42,873,364**	**1.3**	**94.0**	**94.7**	**90.0**
Coal	65,913	49,400	111,720	6.0	.2	.1	.2
Petroleum	7,502	7,282	23,572	13.6	.0	.0	.0
Natural Gas	774,862	756,356	2,847,091	15.6	1.9	1.7	6.0
Other Gases	0	265	0	NM	.0	.0	.0
Hydroelectric	1,534	4,444	0	NM	.0	.0	.0
Other Renewables	1,599,769	1,586,216	1,585,266	−.1	4.0	3.5	3.3
Other	0	0	170,631	NM	.0	.0	.4
Total IPP's & Combined Heat and Power	**2,449,580**	**2,403,962**	**4,738,280**	**7.6**	**6.0**	**5.3**	**10.0**
Coal	18,091,528	22,810,370	23,098,370	2.8	44.7	50.5	48.5
Petroleum	73,126	73,904	159,706	9.1	.2	.2	.3
Natural Gas	2,703,261	2,998,984	4,602,958	6.1	6.7	6.6	9.7
Other Gases	0	265	0	NM	.0	.0	.0
Nuclear	13,521,676	14,208,157	14,558,884	.8	33.4	31.4	30.6
Hydroelectric	4,509,292	3,515,704	3,435,829	−3.0	11.1	7.8	7.2
Other Renewables	1,599,769	1,586,216	1,585,266	−.1	4.0	3.5	3.3
Other	0	0	170,631	NM	.0	.0	.4
Total Electric Industry	**40,498,652**	**45,193,599**	**47,611,644**	**1.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Arkansas				
Coal (2002 cents per million Btu)	189.8	168.5	83.6	−8.7
Average heat value (Btu per pound)	8,665	8,707	8,694	*
Average sulfur Content(percent)	.3	.3	.3	−1.6
Petroleum (2002 cents per million Btu)	510.4	483.3	550.0	.8
Average heat value (Btu per gallon)	136,833	140,074	138,705	.1
Average sulfur Content(percent)	.0	.0	.4	NM
Gas (2002 cents per million Btu)	245.8	269.2	351.4	4.0
Average heat value (Btu per cubic foot)	1,029	1,029	1,019	−.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Arkansas				
Sulfur Dioxide				
Coal	63	85	72	1.5
Petroleum	*	*	1	30.9
Gas	0	0	*	NM
Other	3	4	7	8.2
Total	66	90	80	2.1
Nitrogen Oxide				
Coal	67	41	40	-5.5
Petroleum	*	*	*	17.2
Gas	4	4	3	-1.0
Other	1	1	2	5.0
Total	72	47	45	-5.0
Carbon Dioxide				
Coal	20,491	25,488	26,358	2.8
Petroleum	67	66	163	10.4
Gas	1,877	1,974	2,535	3.4
Other	1	0	0	NM
Total	22,437	27,528	29,057	2.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Arkansas							
Retail Sales (thousand megawatthours)							
Residential	11,762	12,990	15,527	3.1	37.1	35.2	36.6
Commercial	6,698	7,597	9,304	3.7	21.1	20.6	21.9
Industrial	12,609	15,632	16,887	3.3	39.8	42.4	39.8
Other	594	638	731	2.3	1.9	1.7	1.7
Total	31,663	36,858	42,450	3.3	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,084	1,041	1,126	.4	46.4	44.7	47.3
Commercial	525	529	528	.1	22.5	22.7	22.2
Industrial	681	714	678	*	29.1	30.7	28.5
Other	46	43	48	.4	2.0	1.9	2.0
Total	2,335	2,328	2,380	.2	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	9.21	8.02	7.25	-2.6	NA	NA	NA
Commercial	7.84	6.97	5.68	-3.5	NA	NA	NA
Industrial	5.40	4.57	4.01	-3.2	NA	NA	NA
Other	7.72	6.79	6.52	-1.9	NA	NA	NA
Total	7.38	6.32	5.61	-3.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Arkansas						
Number of Entities	4	15	0	17	0	36
Number of Retail Customers	818,661	161,076	0	411,154	0	1,390,891
Retail Sales (thousand megawatthours)	26,161	5,452	0	10,836	0	42,450
Percentage of Retail Sales	61.63	12.84	.00	25.53	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,502	297	0	581	0	2,380
Percentage of Revenue	63.10	12.47	.00	24.43	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.74	5.44	.00	5.37	0	5.61

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
California		
NERC Region(s)		WSCC
Primary Energy Source		Gas
Net Summer Capability (megawatts)	56,663	2
Electric Utilities	24,609	5
Independent Power Producers & Combined Heat and Power	32,054	4
Net Generation (megawatthours)	184,210,030	5
Electric Utilities	74,588,271	15
Independent Power Producers & Combined Heat and Power	109,621,759	4
Emissions (thousand short tons)		
Sulfur Dioxide	48	37
Nitrogen Oxide	72	31
Carbon Dioxide	52,627	17
Sulfur Dioxide/sq. mile	0	46
Nitrogen Oxide/sq. mile	0	42
Carbon Dioxide/sq. mile	337	40
Utility and ESP Retail Electricity Sales (megawatthours)	235,248,942	2
Utility Retail Electricity Sales (megawatthours)	171,531,228	3
ESP Retail Electricity Sales (megawatthours)	63,717,714	1
Direct Use (megawatthours)	29,270,234	2
Average Retail Price (cents/kWh)	12.50	2

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
California			
1. Moss Landing Power Pl	Gas	Duke Energy North America LLC	2,680
2. Diablo Canyon	Nuclear	Pacific Gas & Electric Co	2,174
3. San Onofre	Nuclear	Southern California Edison Co	2,150
4. AES Alamitos LLC	Gas	AES Alamitos LLC	2,083
5. Pittsburg Power	Gas	Mirant Delta LLC	1,906
6. Haynes	Gas	Los Angeles City of	1,570
7. Ormond Beach	Gas	Reliant Energy Ormond Bch LLC	1,499
8. Castaic	Hydro	Los Angeles City of	1,495
9. AES Redondo Beach LLC	Gas	AES Redondo Beach LLC	1,310
10. Helms Pumped Storage	Hydro	Pacific Gas & Electric Co	1,212

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
California					
A. Southern California Edison Co	54,391,384	20,369,957	26,434,396	6,952,221	634,810
B. Pacific Gas and Electric Co	49,830,092	19,088,200	22,933,040	7,179,531	629,321
C. California DWR-Elec Power Fund	45,153,230	16,932,597	21,346,415	6,450,410	423,808
D. Los Angeles Dept of Wtr & Pwr	22,289,149	7,344,707	11,956,556	2,454,582	533,304
E. Sacramento Municipal Util Dist	9,505,300	4,093,714	631,710	4,699,565	80,311
Total	181,169,155	67,829,175	83,302,117	27,736,309	2,301,554
Percentage of Utility Sales	77	86	77	67	32

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
California							
Petroleum	558	590	184	−11.6	1.0	1.1	0.3
Natural Gas	18,022	18,731	1,572	−23.7	33.1	34.8	2.8
Dual Fired	6,258	4,945	4,494	−3.6	11.5	9.2	7.9
Nuclear	4,310	4,310	4,324	.0	7.9	8.0	7.6
Hydroelectric	13,448	13,537	13,770	.3	24.7	25.1	24.3
Other Renewables	1,716	1,597	265	−18.7	3.2	3.0	.5
Total Electric Utilities	**44,313**	**43,709**	**24,609**	**−6.3**	**81.4**	**81.2**	**43.4**
Coal	439	420	352	−2.4	.8	.8	.6
Petroleum	48	46	521	30.2	.1	.1	.9
Natural Gas	3,646	4,468	23,744	23.1	6.7	8.3	41.9
Other Gases	213	171	226	.7	.4	.3	.4
Dual Fired	956	631	2,034	8.7	1.8	1.2	3.6
Hydroelectric	593	588	323	−6.5	1.1	1.1	.6
Other Renewables	4,192	3,819	4,837	1.6	7.7	7.1	8.5
Other	9	9	17	7.8	.0	.0	.0
Total IPP's & Combined Heat and Power	**10,095**	**10,152**	**32,054**	**13.7**	**18.6**	**18.8**	**56.6**
Coal	439	420	352	−2.4	.8	.8	.6
Petroleum	607	636	705	1.7	1.1	1.2	1.2
Natural Gas	21,668	23,198	25,317	1.7	39.8	43.1	44.7
Other Gases	213	171	226	.7	.4	.3	.4
Dual Fired	7,215	5,576	6,527	−1.1	13.3	10.4	11.5
Nuclear	4,310	4,310	4,324	.0	7.9	8.0	7.6
Hydroelectric	14,041	14,125	14,094	.0	25.8	26.2	24.9
Other Renewables	5,908	5,416	5,102	−1.6	10.9	10.1	9.0
Other	9	9	17	7.8	.0	.0	.0
Total Electric Industry	**54,408**	**53,861**	**56,663**	**.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
California							
Petroleum	2,007,674	141,872	43,933	-34.6	1.1	0.1	0.0
Natural Gas	46,499,103	36,300,778	8,808,012	-16.9	24.9	21.0	4.8
Nuclear	31,580,692	30,512,118	34,352,340	.9	16.9	17.7	18.6
Hydroelectric	38,264,443	39,797,042	29,995,647	-2.7	20.5	23.0	16.3
Other Renewables	7,430,151	5,431,253	1,388,339	-17.0	4.0	3.1	.8
Total Electric Utilities	**125,782,063**	**112,183,063**	**74,588,271**	**-5.6**	**67.3**	**64.9**	**40.5**
Coal	3,129,951	2,331,970	2,327,809	-3.2	1.7	1.3	1.3
Petroleum	1,594,009	1,950,319	1,917,133	2.1	.9	1.1	1.0
Natural Gas	33,145,067	34,701,286	80,816,032	10.4	17.7	20.1	43.9
Other Gases	3,097,462	2,984,277	1,240,053	-9.7	1.7	1.7	.7
Hydroelectric	2,511,007	2,271,408	903,984	-10.7	1.3	1.3	.5
Other Renewables	17,719,662	16,353,592	22,292,229	2.6	9.5	9.5	12.1
Other	11,423	21,680	124,520	30.4	.0	.0	.1
Total IPP's & Combined Heat and Power	**61,208,582**	**60,614,532**	**109,621,759**	**6.7**	**32.7**	**35.1**	**59.5**
Coal	3,129,951	2,331,970	2,327,809	-3.2	1.7	1.3	1.3
Petroleum	3,601,683	2,092,191	1,961,066	-6.5	1.9	1.2	1.1
Natural Gas	79,644,170	71,002,064	89,624,044	1.3	42.6	41.1	48.7
Other Gases	3,097,462	2,984,277	1,240,053	-9.7	1.7	1.7	.7
Nuclear	31,580,692	30,512,118	34,352,340	.9	16.9	17.7	18.6
Hydroelectric	40,775,450	42,068,450	30,899,631	-3.0	21.8	24.3	16.8
Other Renewables	25,149,813	21,784,845	23,680,568	-.7	13.4	12.6	12.9
Other	11,423	21,680	124,520	30.4	.0	.0	.1
Total Electric Industry	**186,990,645**	**172,797,595**	**184,210,030**	**-.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
California				
Coal (2002 cents per million Btu)	0.0	0.0	180.2	NM
Average heat value (Btu per pound)	0	0	11,868	NM
Average sulfur Content(percent)	.0	.0	.5	NM
Petroleum (2002 cents per million Btu)	261.7	.0	114.4	-8.8
Average heat value (Btu per gallon)	146,727	0	96,990	-4.5
Average sulfur Content(percent)	.3	.0	1.9	23.9
Gas (2002 cents per million Btu)	330.3	310.6	372.1	1.3
Average heat value (Btu per cubic foot)	1,030	1,019	1,019	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
California				
Sulfur Dioxide				
Coal	23	20	6	-13.9
Petroleum	16	25	42	11.1
Gas	*	*	*	.0
Other	1	1	1	3.0
Total	40	46	48	2.2
Nitrogen Oxide				
Coal	12	9	9	-3.4
Petroleum	5	6	8	5.6
Gas	61	46	44	-3.6
Other	10	10	11	.9
Total	89	70	72	-2.3
Carbon Dioxide				
Coal	3,365	2,330	2,600	-2.8
Petroleum	3,503	2,420	3,019	-1.6
Gas	44,487	39,565	46,901	.6
Other	103	99	106	.3
Total	51,459	44,414	52,627	.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
California							
Retail Sales (thousand megawatthours)							
Residential	67,359	73,086	78,556	1.7	32.0	32.1	33.4
Commercial	79,058	83,570	108,295	3.6	37.6	36.7	46.0
Industrial	56,189	62,017	41,124	-3.4	26.7	27.2	17.5
Other	7,894	9,203	7,274	-.9	3.8	4.0	3.1
Total	210,500	227,876	235,249	1.2	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	8,481	8,638	10,136	2.0	37.3	38.6	34.5
Commercial	9,212	8,573	14,321	5.0	40.5	38.4	48.7
Industrial	4,590	4,431	4,454	-.3	20.2	19.8	15.1
Other	444	710	486	1.0	1.9	3.2	1.6
Total	22,726	22,352	29,398	2.9	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	12.59	11.82	12.90	.3	NA	NA	NA
Commercial	11.65	10.26	13.22	1.4	NA	NA	NA
Industrial	8.17	7.14	10.83	3.2	NA	NA	NA
Other	5.62	7.71	6.68	1.9	NA	NA	NA
Total	10.80	9.81	12.50	1.6	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
California						
Number of Entities	6	35	0	4	14	59
Number of Retail Customers	10,563,127	2,968,938	0	14,377	76,483	13,622,925
Retail Sales (thousand megawatthours)	112,860	58,411	0	260	63,718	235,249
Percentage of Retail Sales	47.97	24.83	.00	.11	27.09	100.00
Revenue from Retail Sales (million 2002 dollars)	18,821	5,210	0	22	5,345	29,398
Percentage of Revenue	64.02	17.72	.00	.08	18.18	100.00
Revenue per Kilowatthour (2002 cents/kWh)	16.68	8.92	.00	8.54	0	12.50

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Colorado		
NERC Region(s)		WSCC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	9,435	32
Electric Utilities	7,603	28
Independent Power Producers & Combined Heat and Power	1,833	30
Net Generation (megawatthours)	45,600,388	30
Electric Utilities	41,509,933	26
Independent Power Producers & Combined Heat and Power	4,090,455	34
Emissions (thousand short tons)		
Sulfur Dioxide	90	27
Nitrogen Oxide	79	28
Carbon Dioxide	44,590	23
Sulfur Dioxide/sq. mile	1	37
Nitrogen Oxide/sq. mile	1	39
Carbon Dioxide/sq. mile	430	39
Utility and ESP Retail Electricity Sales (megawatthours)	45,936,696	27
Utility Retail Electricity Sales (megawatthours)	45,936,696	26
Direct Use (megawatthours)	416,999	32
Average Retail Price (cents/kWh)	6.00	34

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Colorado			
1. Craig	Petroleum, Gas, Coal	Tri-State G & T Assn Inc	1,264
2. Cherokee	Gas, Coal	Public Service Co of Colorado	722
3. Fort St Vrain	Gas	Public Service Co of Colorado	691
4. Comanche	Gas, Coal	Public Service Co of Colorado	660
5. Pawnee	Gas, Coal	Public Service Co of Colorado	505
6. Rawhide	Petroleum, Gas, Coal	Platte River Power Authority	450
7. Hayden	Petroleum, Gas, Coal	Public Service Co of Colorado	446
8. Cabin Creek	Hydro	Public Service Co of Colorado	324
9. Ray D Nixon	Petroleum, Gas, Coal	Colorado Springs City of	268
10. Manchief Electric Gen	Gas	Manchief Power Co LLC	264

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Colorado					
A. Public Service Co of Colorado	25,814,418	8,128,867	12,396,124	5,011,832	277,595
B. Colorado Springs Utilities	4,293,863	1,274,181	1,376,755	1,179,479	463,448
C. Intermountain Rural Elec Assn	1,659,282	1,062,908	485,736	97,645	12,993
D. UtiliCorp United, Inc	1,643,020	542,896	604,326	410,067	85,731
E. Fort Collins Utilities	1,302,636	422,426	458,585	421,419	206
Total	34,713,219	11,431,278	15,321,526	7,120,442	839,973
Percentage of Utility Sales	76	74	83	67	60

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Colorado							
Coal	4,950	4,955	4,891	-0.1	71.0	65.8	51.8
Petroleum	141	141	162	1.5	2.0	1.9	1.7
Natural Gas	35	154	944	44.3	.5	2.0	10.0
Dual Fired	424	423	420	-.1	6.1	5.6	4.5
Hydroelectric	1,098	1,178	1,162	.6	15.7	15.6	12.3
Other Renewables	0	0	24	NM	.0	.0	.3
Total Electric Utilities	**6,648**	**6,850**	**7,603**	**1.5**	**95.3**	**91.0**	**80.6**
Coal	33	33	40	2.4	.5	.4	.4
Petroleum	4	7	2	-6.5	.1	.1	.0
Natural Gas	227	565	1,426	22.6	3.3	7.5	15.1
Dual Fired	28	28	298	30.3	.4	.4	3.2
Hydroelectric	30	38	43	4.3	.4	.5	.5
Other Renewables	5	5	23	19.1	.1	.1	.2
Total IPP's & Combined Heat and Power	**326**	**676**	**1,833**	**21.2**	**4.7**	**9.0**	**19.4**
Coal	4,982	4,988	4,931	-.1	71.4	66.3	52.3
Petroleum	146	148	164	1.3	2.1	2.0	1.7
Natural Gas	262	719	2,370	27.7	3.8	9.6	25.1
Dual Fired	452	452	718	5.3	6.5	6.0	7.6
Hydroelectric	1,128	1,215	1,206	.7	16.2	16.1	12.8
Other Renewables	5	5	47	29.2	.1	.1	.5
Total Electric Industry	**6,974**	**7,526**	**9,435**	**3.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Colorado							
Coal	30,456,351	32,002,082	35,135,198	1.6	88.9	85.0	77.1
Petroleum	8,898	14,623	22,519	10.9	.0	.0	.0
Natural Gas	364,237	423,540	5,321,770	34.7	1.1	1.1	11.7
Other Gases	0	0	2,884	NM	.0	.0	.0
Hydroelectric	1,857,831	1,935,328	967,575	-7.0	5.4	5.1	2.1
Other Renewables	0	0	59,987	NM	.0	.0	.1
Total Electric Utilities	**32,687,317**	**34,375,573**	**41,509,933**	**2.7**	**95.5**	**91.3**	**91.0**
Coal	244,968	250,938	253,053	.4	.7	.7	.6
Petroleum	68	861	661	28.7	.0	.0	.0
Natural Gas	1,146,627	2,848,632	3,706,720	13.9	3.3	7.6	8.1
Hydroelectric	126,756	133,998	21,168	-18.0	.4	.4	.0
Other Renewables	34,449	32,558	108,853	13.6	.1	.1	.2
Total IPP's & Combined Heat and Power	**1,552,867**	**3,266,988**	**4,090,455**	**11.4**	**4.5**	**8.7**	**9.0**
Coal	30,701,319	32,253,020	35,388,251	1.6	89.7	85.7	77.6
Petroleum	8,966	15,484	23,180	11.1	.0	.0	.1
Natural Gas	1,510,864	3,272,172	9,028,490	22.0	4.4	8.7	19.8
Other Gases	0	0	2,884	NM	.0	.0	.0
Hydroelectric	1,984,587	2,069,326	988,743	-7.4	5.8	5.5	2.2
Other Renewables	34,449	32,558	168,840	19.3	.1	.1	.4
Total Electric Industry	**34,240,184**	**37,642,561**	**45,600,388**	**3.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Colorado				
Coal (2002 cents per million Btu)	121.7	103.8	95.1	–2.7
Average heat value (Btu per pound)	9,888	9,872	9,787	–.1
Average sulfur Content(percent)	.4	.4	.4	.5
Petroleum (2002 cents per million Btu)	393.3	.0	704.6	6.7
Average heat value (Btu per gallon)	117,493	0	137,395	1.8
Average sulfur Content(percent)	6.0	.0	*	–46.9
Gas (2002 cents per million Btu)	278.8	326.3	246.3	–1.4
Average heat value (Btu per cubic foot)	1,012	995	1,019	.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Colorado				
Sulfur Dioxide				
Coal	89	102	90	0.2
Petroleum	0	*	*	NM
Gas	0	*	*	NM
Other	*	*	0	NM
Total	89	102	90	.2
Nitrogen Oxide				
Coal	130	83	74	–6.1
Petroleum	0	0	0	NM
Gas	2	3	5	12.3
Other	*	*	*	1.2
Total	132	86	79	–5.6
Carbon Dioxide				
Coal	33,696	35,279	39,521	1.8
Petroleum	13	18	25	7.5
Gas	837	1,624	5,045	22.1
Total	34,546	36,921	44,590	2.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Colorado							
Retail Sales (thousand megawatthours)							
Residential	10,656	12,261	15,425	4.2	32.3	32.2	33.6
Commercial	14,422	14,600	18,438	2.8	43.8	38.3	40.1
Industrial	7,024	10,297	10,672	4.8	21.3	27.0	23.2
Other	856	911	1,401	5.6	2.6	2.4	3.0
Total	32,958	38,069	45,937	3.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	859	935	1,137	3.2	38.7	40.2	41.2
Commercial	935	865	1,045	1.3	42.1	37.2	37.9
Industrial	354	453	483	3.5	15.9	19.5	17.5
Other	74	75	93	2.6	3.3	3.2	3.4
Total	2,221	2,328	2,758	2.4	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.07	7.62	7.37	−1.0	NA	NA	NA
Commercial	6.48	5.92	5.67	−1.5	NA	NA	NA
Industrial	5.04	4.40	4.52	−1.2	NA	NA	NA
Other	8.60	8.22	6.64	−2.8	NA	NA	NA
Total	6.74	6.11	6.00	−1.3	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Colorado						
Number of Entities	2	30	0	28	0	60
Number of Retail Customers	1,345,055	381,315	0	491,371	0	2,217,741
Retail Sales (thousand megawatthours)	27,457	8,219	0	10,260	0	45,937
Percentage of Retail Sales	59.77	17.89	.00	22.34	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,583	458	0	717	0	2,758
Percentage of Revenue	57.40	16.60	.00	26.00	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.77	5.57	.00	6.99	0	6.00

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Connecticut		
NERC Region(s)		NPCC
Primary Energy Source		Nuclear
Net Summer Capability (megawatts)	7,400	34
Electric Utilities	34	48
Independent Power Producers & Combined Heat and Power	7,365	11
Net Generation (megawatthours)	31,311,218	38
Electric Utilities	21,463	48
Independent Power Producers & Combined Heat and Power	31,289,755	11
Emissions (thousand short tons)		
Sulfur Dioxide	11	46
Nitrogen Oxide	10	45
Carbon Dioxide	9,719	40
Sulfur Dioxide/sq. mile	2	29
Nitrogen Oxide/sq. mile	2	23
Carbon Dioxide/sq. mile	2,006	13
Utility and ESP Retail Electricity Sales (megawatthours)	30,905,605	33
Utility Retail Electricity Sales (megawatthours)	30,615,280	33
ESP Retail Electricity Sales (megawatthours)	290,325	16
Direct Use (megawatthours)	2,774,346	15
Average Retail Price (cents/kWh)	9.73	9

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Connecticut			
1. Millstone	Nuclear	Dominion Nuclear Conn Inc	2,006
2. Middletown	Other, Petroleum, Gas	NRG Middletown Operations Inc	837
3. Lake Road Generating	Petroleum, Gas	Lake Road Generating Co LP	696
4. Montville Station	Gas, Petroleum	NRG Montville Operations Inc	496
5. New Haven Harbor	Gas, Petroleum	PSEG Power Connecticut LLC	461
6. Bridgeport Energy Pro	Gas	Bridgeport Energy LLC	454
7. Bridgeport Station	Petroleum, Coal	PSEG Power Connecticut LLC	417
8. Devon Station	Petroleum, Gas	NRG Devon Operations Inc	351
9. NRG Norwalk Harbor	Petroleum	NRG Norwalk Harbor Ops Inc	342
10. PPL Wallingford Energ	Gas	PPL Wallingford Energy LLC	190

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Connecticut					
A. Connecticut Light & Power Co	22,951,701	9,525,042	9,561,822	3,573,159	291,678
B. United Illuminating Company	5,781,010	2,247,196	2,465,711	1,021,586	46,517
C. Town of Wallingford	608,893	201,498	200,187	184,179	23,029
D. City of Groton Dept of Utils	568,347	107,338	120,168	332,755	8,086
E. City of Norwich	328,438	117,661	129,629	54,354	26,794
Total	30,238,389	12,198,735	12,477,517	5,166,033	396,104
Percentage of Utility Sales	98	98	100	96	72

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Connecticut							
Coal	385	385	0	NM	5.2	5.5	0.0
Petroleum	2,429	2,273	25	-39.8	33.0	32.7	.3
Natural Gas	0	341	0	NM	.0	4.9	.0
Dual Fired	528	528	0	NM	7.2	7.6	.0
Nuclear	3,211	2,631	0	NM	43.7	37.8	.0
Hydroelectric	137	136	9	-25.9	1.9	2.0	.1
Other Renewables	64	0	0	NM	.9	.0	.0
Total Electric Utilities	**6,754**	**6,294**	**34**	**-44.4**	**91.9**	**90.5**	**.5**
Coal	200	200	553	11.9	2.7	2.9	7.5
Petroleum	0	0	1,229	NM	.0	.0	16.6
Natural Gas	43	14	832	38.9	.6	.2	11.2
Dual Fired	199	184	2,350	31.5	2.7	2.6	31.8
Nuclear	0	0	2,006	NM	.0	.0	27.1
Hydroelectric	21	21	141	23.7	.3	.3	1.9
Other Renewables	135	241	254	7.3	1.8	3.5	3.4
Other	0	3	1	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**599**	**663**	**7,365**	**32.2**	**8.1**	**9.5**	**99.5**
Coal	585	585	553	-.6	8.0	8.4	7.5
Petroleum	2,429	2,273	1,254	-7.1	33.0	32.7	16.9
Natural Gas	43	355	832	38.9	.6	5.1	11.2
Dual Fired	727	712	2,350	13.9	9.9	10.2	31.8
Nuclear	3,211	2,631	2,006	-5.1	43.7	37.8	27.1
Hydroelectric	158	157	150	-.5	2.1	2.3	2.0
Other Renewables	199	241	254	2.7	2.7	3.5	3.4
Other	0	3	1	NM	.0	.0	.0
Total Electric Industry	**7,353**	**6,957**	**7,400**	**.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Connecticut							
Coal	1,907,826	2,557,934	0	NM	5.8	14.5	0.0
Petroleum	4,206,354	8,431,425	928	-60.8	12.8	47.7	.0
Natural Gas	47,401	1,545,712	0	NM	.1	8.7	.0
Nuclear	21,801,782	-124,722	0	NM	66.3	-.7	.0
Hydroelectric	345,409	366,668	20,535	-26.9	1.1	2.1	.1
Other Renewables	406,095	450,749	0	NM	1.2	2.6	.0
Total Electric Utilities	**28,714,867**	**13,227,766**	**21,463**	**-55.1**	**87.3**	**74.8**	**.1**
Coal	1,600,491	1,601,210	3,227,202	8.1	4.9	9.1	10.3
Petroleum	178,147	77,284	2,336,957	33.1	.5	.4	7.5
Natural Gas	1,336,515	1,049,652	8,868,470	23.4	4.1	5.9	28.3
Other Gases	0	51	8,834	NM	.0	.0	.0
Nuclear	0	0	14,918,272	NM	.0	.0	47.6
Hydroelectric	65,022	72,585	304,352	18.7	.2	.4	1.0
Other Renewables	989,528	1,645,749	1,625,668	5.7	3.0	9.3	5.2
Total IPP's & Combined Heat and Power	**4,169,704**	**4,446,530**	**31,289,755**	**25.1**	**12.7**	**25.2**	**99.9**
Coal	3,508,317	4,159,144	3,227,202	-.9	10.7	23.5	10.3
Petroleum	4,384,501	8,508,709	2,337,885	-6.7	13.3	48.1	7.5
Natural Gas	1,383,916	2,595,364	8,868,470	22.9	4.2	14.7	28.3
Other Gases	0	51	8,834	NM	.0	.0	.0
Nuclear	21,801,782	-124,722	14,918,272	-4.1	66.3	-.7	47.6
Hydroelectric	410,431	439,253	324,887	-2.6	1.2	2.5	1.0
Other Renewables	1,395,623	2,096,498	1,625,668	1.7	4.2	11.9	5.2
Total Electric Industry	**32,884,571**	**17,674,296**	**31,311,218**	**-.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Connecticut				
Coal (2002 cents per million Btu)	190.0	195.8	244.9	2.9
Average heat value (Btu per pound)	13,144	13,132	11,309	-1.6
Average sulfur Content(percent)	.6	.5	.9	5.4
Petroleum (2002 cents per million Btu)	267.3	300.8	422.4	5.2
Average heat value (Btu per gallon)	151,739	152,432	149,929	-.1
Average sulfur Content(percent)	.8	.7	.4	-8.1
Gas (2002 cents per million Btu)	421.2	248.8	392.0	-.8
Average heat value (Btu per cubic foot)	1,032	1,019	1,023	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Connecticut				
Sulfur Dioxide				
Coal	9	13	4	-8.9
Petroleum	22	40	7	-12.0
Gas	0	0	*	NM
Other	1	*	*	-10.8
Total	32	53	11	-11.0
Nitrogen Oxide				
Coal	10	10	2	-15.9
Petroleum	4	12	2	-5.7
Gas	1	3	2	5.8
Other	4	4	3	-2.5
Total	20	28	10	-7.6
Carbon Dioxide				
Coal	3,597	4,510	3,373	-.7
Petroleum	3,954	7,657	2,048	-7.0
Gas	659	1,534	3,999	22.2
Other	167	290	299	6.7
Total	8,376	13,991	9,719	1.7

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Connecticut							
Retail Sales (thousand megawatthours)							
Residential	10,597	10,859	12,459	1.8	38.9	38.2	40.3
Commercial	10,677	11,278	12,532	1.8	39.2	39.7	40.5
Industrial	5,597	5,919	5,367	-.5	20.5	20.8	17.4
Other	368	376	548	4.5	1.3	1.3	1.8
Total	27,238	28,432	30,906	1.4	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,345	1,354	1,366	.2	43.2	44.0	45.4
Commercial	1,194	1,191	1,172	-.2	38.3	38.8	39.0
Industrial	517	472	412	-2.5	16.6	15.4	13.7
Other	58	56	57	-.2	1.8	1.8	1.9
Total	3,114	3,073	3,007	-.4	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	12.69	12.47	10.96	-1.6	NA	NA	NA
Commercial	11.18	10.56	9.35	-2.0	NA	NA	NA
Industrial	9.23	7.97	7.68	-2.0	NA	NA	NA
Other	15.69	14.92	10.36	-4.5	NA	NA	NA
Total	11.43	10.81	9.73	-1.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Connecticut						
Number of Entities	3	7	0	0	4	14
Number of Retail Customers	1,464,597	68,330	0	0	22,063	1,554,990
Retail Sales (thousand megawatthours)	28,751	1,864	0	0	290	30,906
Percentage of Retail Sales	93.03	6.03	.00	.00	.94	100.00
Revenue from Retail Sales (million 2002 dollars)	2,851	143	0	0	14	3,007
Percentage of Revenue	94.80	4.75	.00	.00	.46	100.00
Revenue per Kilowatthour (2002 cents/kWh)	9.91	7.66	.00	.00	0	9.73

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Delaware		
NERC Region(s)		MACC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	3,390	44
Electric Utilities	58	47
Independent Power Producers & Combined Heat and Power	3,332	22
Net Generation (megawatthours)	6,002,490	49
Electric Utilities	170,994	46
Independent Power Producers & Combined Heat and Power	5,831,496	30
Emissions (thousand short tons)		
Sulfur Dioxide	33	40
Nitrogen Oxide	12	42
Carbon Dioxide	5,989	44
Sulfur Dioxide/sq. mile	17	7
Nitrogen Oxide/sq. mile	6	6
Carbon Dioxide/sq. mile	3,063	8
Utility and ESP Retail Electricity Sales (megawatthours)	11,557,069	42
Utility Retail Electricity Sales (megawatthours)	10,863,633	41
ESP Retail Electricity Sales (megawatthours)	693,436	15
Direct Use (megawatthours)	346,740	35
Average Retail Price (cents/kWh)	7.05	17

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Delaware			
1. Hay Road	Petroleum, Gas	Conectiv Delmarva Gen Inc	1,060
2. Indian River Operatio	Petroleum, Coal	Indian River Operations Inc	784
3. Edge Moor	Gas, Petroleum, Coal	Conectiv Delmarva Gen Inc	717
4. Delaware City Plant	Petroleum, Gas	Motiva Enterprises LLC	382
5. McKee Run	Gas, Petroleum	DFD Operating Services LLC	136
6. Dover Energy	Gas, Petroleum	NRG Energy Center Dover LLC	120
7. NA1	Gas, Petroleum	Delaware Municipal Electric Cor	49
8. Christiana	Petroleum	Conectiv Delmarva Gen Inc	45
9. Van Sant Station	Gas, Petroleum	DFD Operating Services LLC	39
10. Delaware City 10	Petroleum	Conectiv Delmarva Gen Inc	16

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Delaware					
A. Delmarva Power & Light Company	8,297,881	2,817,181	3,166,888	2,274,693	39,119
B. Delaware Electric Coop, Inc	891,013	738,403	136,572	9,996	6,042
C. City of Dover	747,980	179,763	215,077	344,415	8,725
D. Conectiv Energy Supply, Inc	419,577	0	2,501	417,076	0
E. City of Newark	381,645	93,695	65,212	222,738	0
Total	10,738,096	3,829,042	3,586,250	3,268,918	53,886
Percentage of Utility Sales	93	95	90	95	60

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Delaware							
Coal	931	1,019	0	NM	38.1	41.7	0.0
Petroleum	124	572	9	-25.6	5.1	23.4	.3
Natural Gas	399	175	0	NM	16.3	7.2	.0
Dual Fired	815	511	49	-26.8	33.3	20.9	1.4
Total Electric Utilities	**2,269**	**2,277**	**58**	**-33.5**	**92.8**	**93.2**	**1.7**
Coal	37	27	1,050	45.0	1.5	1.1	31.0
Petroleum	134	135	561	17.2	5.5	5.5	16.5
Natural Gas	0	0	184	NM	.0	.0	5.4
Other Gases	1	0	303	84.9	.0	.0	8.9
Dual Fired	4	4	1,235	87.4	.2	.2	36.4
Total IPP's & Combined Heat and Power	**177**	**167**	**3,332**	**38.6**	**7.2**	**6.8**	**98.3**
Coal	968	1,046	1,050	.9	39.6	42.8	31.0
Petroleum	258	707	570	9.2	10.5	28.9	16.8
Natural Gas	399	175	184	-8.3	16.3	7.2	5.4
Other Gases	1	0	303	84.9	.0	.0	8.9
Dual Fired	819	515	1,284	5.1	33.5	21.1	37.9
Total Electric Industry	**2,446**	**2,443**	**3,390**	**3.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Delaware							
Coal	5,185,396	3,925,643	0	NM	57.5	54.4	0.0
Petroleum	2,094,383	832,577	154,118	-25.2	23.2	11.5	2.6
Natural Gas	1,026,683	1,820,379	16,876	-36.6	11.4	25.2	.3
Total Electric Utilities	**8,306,462**	**6,578,599**	**170,994**	**-35.0**	**92.1**	**91.1**	**2.8**
Coal	189,219	74,941	3,463,565	38.1	2.1	1.0	57.7
Petroleum	410,238	382,924	795,578	7.6	4.5	5.3	13.3
Natural Gas	2,507	8,379	1,426,007	102.3	.0	.1	23.8
Other Gases	103,206	177,792	146,346	4.0	1.1	2.5	2.4
Other	6,049	0	0	NM	.1	.0	.0
Total IPP's & Combined Heat and Power	**711,219**	**644,036**	**5,831,496**	**26.3**	**7.9**	**8.9**	**97.2**
Coal	5,374,615	4,000,584	3,463,565	-4.8	59.6	55.4	57.7
Petroleum	2,504,621	1,215,501	949,696	-10.2	27.8	16.8	15.8
Natural Gas	1,029,190	1,828,758	1,442,883	3.8	11.4	25.3	24.0
Other Gases	103,206	177,792	146,346	4.0	1.1	2.5	2.4
Other	6,049	0	0	NM	.1	.0	.0
Total Electric Industry	**9,017,681**	**7,222,635**	**6,002,490**	**-4.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Delaware				
Coal (2002 cents per million Btu)	188.4	161.5	177.8	-0.6
Average heat value (Btu per pound)	13,027	13,062	12,352	-.6
Average sulfur Content(percent)	.9	1.0	.9	-.3
Petroleum (2002 cents per million Btu)	256.4	285.7	405.6	5.2
Average heat value (Btu per gallon)	151,287	151,465	146,095	-.4
Average sulfur Content(percent)	.9	.9	.7	-3.3
Gas (2002 cents per million Btu)	290.8	313.2	374.9	2.9
Average heat value (Btu per cubic foot)	1,033	1,035	1,023	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Delaware				
Sulfur Dioxide				
Coal	41	37	29	-3.5
Petroleum	22	18	3	-18.9
Gas	0	0	0	NM
Other	*	0	0	NM
Total	63	55	33	-7.0
Nitrogen Oxide				
Coal	21	14	8	-10.7
Petroleum	4	2	2	-7.0
Gas	1	1	2	6.6
Total	26	17	12	-8.3
Carbon Dioxide				
Coal	6,125	4,580	3,934	-4.8
Petroleum	2,189	1,197	863	-9.8
Gas	584	1,113	1,191	8.3
Total	8,898	6,891	5,989	-4.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Delaware							
Retail Sales (thousand megawatthours)							
Residential	3,044	3,257	4,020	3.1	33.4	32.2	34.8
Commercial	2,605	3,068	3,994	4.9	28.6	30.3	34.6
Industrial	3,417	3,741	3,452	.1	37.5	37.0	29.9
Other	56	56	90	5.5	.6	.5	.8
Total	9,121	10,122	11,557	2.7	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	306	309	350	1.5	43.1	42.4	42.9
Commercial	210	227	279	3.2	29.7	31.1	34.2
Industrial	186	185	177	–.6	26.2	25.5	21.7
Other	7	7	10	3.0	1.0	1.0	1.2
Total	709	728	815	1.5	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	10.04	9.48	8.70	–1.6	NA	NA	NA
Commercial	8.08	7.39	6.98	–1.6	NA	NA	NA
Industrial	5.44	4.96	5.11	–.7	NA	NA	NA
Other	13.12	12.80	10.62	–2.3	NA	NA	NA
Total	7.78	7.19	7.05	–1.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Delaware						
Number of Entities	1	9	0	1	5	16
Number of Retail Customers	276,332	53,148	0	62,643	12	392,135
Retail Sales (thousand megawatthours)	8,298	1,675	0	891	693	11,557
Percentage of Retail Sales	71.80	14.49	.00	7.71	6.00	100.00
Revenue from Retail Sales (million 2002 dollars)	576	137	0	76	26	815
Percentage of Revenue	70.73	16.81	.00	9.30	3.16	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.95	8.18	.00	8.50	0	7.05

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
District of Columbia		
NERC Region(s)		MAAC
Primary Energy Source		Petroleum
Net Summer Capability (megawatts)	806	51
Independent Power Producers & Combined Heat and Power	806	40
Net Generation (megawatthours)	261,980	51
Independent Power Producers & Combined Heat and Power	261,980	48
Emissions (thousand short tons)		
Sulfur Dioxide	1	49
Nitrogen Oxide	1	50
Carbon Dioxide	288	50
Sulfur Dioxide/sq. mile	18	6
Nitrogen Oxide/sq. mile	11	2
Carbon Dioxide/sq. mile	4,721	1
Utility and ESP Retail Electricity Sales (megawatthours)	11,066,099	43
Utility Retail Electricity Sales (megawatthours)	5,680,946	48
ESP Retail Electricity Sales (megawatthours)	5,385,153	9
Direct Use (megawatthours)	–7,528	43
Average Retail Price (cents/kWh)	7.37	14

See footnotes at end of tables.

Table 2. Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
District of Columbia			
1. Benning	Petroleum	Potomac Power Resources	550
2. Buzzard Point	Petroleum	Potomac Power Resources	256

See footnotes at end of tables.

Table 3. Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
District of Columbia					
A. Potomac Electric Power Company	5,680,946	1,660,279	3,635,358	282,397	102,912
B. Washington Gas Engy Serv Inc	2,948,389	179,698	2,462,677	0	306,014
C. Power Choice	2,436,764	60,745	2,376,019	0	0
Total	11,066,099	1,900,722	8,474,054	282,397	408,926
Percentage of Utility Sales	100	100	100	100	100

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
District of Columbia							
Petroleum	806	806	0	NM	99.7	100.0	0.0
Total Electric Utilities	806	806	0	NM	99.7	100.0	.0
Coal	3	0	0	NM	.3	.0	.0
Petroleum	0	0	806	NM	.0	.0	100.0
Total IPP's & Combined Heat and Power	3	0	806	89.0	.3	.0	100.0
Coal	3	0	0	NM	.3	.0	.0
Petroleum	806	806	806	.0	99.7	100.0	100.0
Total Electric Industry	809	806	806	.0	100.0	100.0	100.0

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
District of Columbia							
Petroleum	188,452	70,661	0	NM	100.0	100.0	0.0
Total Electric Utilities	188,452	70,661	0	NM	100.0	100.0	.0
Petroleum	0	0	261,980	NM	.0	.0	100.0
Total IPP's & Combined Heat and Power	0	0	261,980	NM	.0	.0	100.0
Petroleum	188,452	70,661	261,980	3.7	100.0	100.0	100.0
Total Electric Industry	188,452	70,661	261,980	3.7	100.0	100.0	100.0

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
District of Columbia				
Petroleum (2002 cents per million Btu)	338.7	367.6	498.8	4.4
Average heat value (Btu per gallon)	143,552	144,404	138,483	–.4
Average sulfur Content(percent)	.9	1.0	.6	–4.8

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
District of Columbia				
Petroleum	1	*	1	-2.3
Total	1	*	1	-2.3
Petroleum	*	*	1	12.2
Total	*	*	1	12.2
Petroleum	241	98	288	2.0
Total	241	98	288	2.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
District of Columbia							
Retail Sales (thousand megawatthours)							
Residential	1,635	1,554	1,901	1.7	15.8	15.4	17.2
Commercial	5,418	7,925	8,474	5.1	52.2	78.4	76.6
Industrial	2,976	262	282	-23.0	28.7	2.6	2.5
Other	346	366	409	1.9	3.3	3.6	3.7
Total	10,375	10,107	11,066	.7	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	131	126	149	1.4	16.7	16.4	18.2
Commercial	431	605	626	4.2	55.1	78.9	76.7
Industrial	196	12	14	-25.4	25.0	1.5	1.7
Other	25	25	27	.9	3.2	3.2	3.3
Total	783	767	815	.4	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.00	8.09	7.82	-.3	NA	NA	NA
Commercial	7.96	7.64	7.38	-.8	NA	NA	NA
Industrial	6.59	4.55	4.95	-3.1	NA	NA	NA
Other	7.20	6.72	6.60	-1.0	NA	NA	NA
Total	7.55	7.59	7.37	-.3	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
District of Columbia						
Number of Entities	1	0	0	0	2	3
Number of Retail Customers	207,424	0	0	0	24,560	231,984
Retail Sales (thousand megawatthours)	5,681	0	0	0	5,385	11,066
Percentage of Retail Sales	51.34	.00	.00	.00	48.66	100.00
Revenue from Retail Sales (million 2002 dollars)	583	0	0	0	233	815
Percentage of Revenue	71.46	.00	.00	.00	28.54	100.00
Revenue per Kilowatthour (2002 cents/kWh)	10.26	.00	.00	.00	0	7.37

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Florida		
NERC Region(s)		FRCC/SERC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	47,054	3
Electric Utilities	40,313	1
Independent Power Producers & Combined Heat and Power	6,740	12
Net Generation (megawatthours)	203,352,775	3
Electric Utilities	182,346,629	1
Independent Power Producers & Combined Heat and Power	21,006,146	13
Emissions (thousand short tons)		
Sulfur Dioxide	502	7
Nitrogen Oxide	289	4
Carbon Dioxide	131,482	3
Sulfur Dioxide/sq. mile	9	12
Nitrogen Oxide/sq. mile	5	8
Carbon Dioxide/sq. mile	2,438	11
Utility and ESP Retail Electricity Sales (megawatthours)	210,473,530	3
Utility Retail Electricity Sales (megawatthours)	210,473,530	2
Direct Use (megawatthours)	6,576,949	6
Average Retail Price (cents/kWh)	7.31	15

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Florida			
1. Crystal River	Petroleum, Nuclear, Coal	Florida Power Corp	3,144
2. Martin	Petroleum, Gas	Florida Power & Light Co	2,850
3. Turkey Point	Gas, Petroleum, Nuclear	Florida Power & Light Co	2,198
4. Fort Myers	Petroleum, Gas	Florida Power & Light Co	2,059
5. Big Bend	Petroleum, Coal	Tampa Electric Co	1,852
6. Lauderdale	Petroleum, Gas	Florida Power & Light Co	1,694
7. St Lucie	Nuclear	Florida Power & Light Co	1,678
8. Port Everglades	Gas, Petroleum	Florida Power & Light Co	1,632
9. Manatee	Gas, Petroleum	Florida Power & Light Co	1,620
10. Seminole	Petroleum, Coal	Seminole Electric Coop Inc	1,316

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Florida					
A. Florida Power & Light Company	95,542,625	50,875,435	40,037,337	4,058,048	571,805
B. Florida Power Corporation	36,859,347	18,753,816	11,420,084	3,835,061	2,850,386
C. Tampa Electric Company	17,925,140	8,046,430	5,831,617	2,611,973	1,435,120
D. JEA	11,925,601	5,072,732	3,839,135	2,901,895	111,839
E. Gulf Power Company	10,771,897	5,143,802	3,552,931	2,053,668	21,496
Total	173,024,610	87,892,215	64,681,104	15,460,645	4,990,646
Percentage of Utility Sales	82	81	83	82	86

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Florida							
Coal	10,030	10,823	11,301	1.3	27.0	26.8	24.0
Petroleum	5,568	5,693	4,894	−1.4	15.0	14.1	10.4
Natural Gas	2,669	3,515	3,570	3.3	7.2	8.7	7.6
Dual Fired	12,674	12,770	16,587	3.0	34.1	31.6	35.3
Nuclear	3,826	3,876	3,906	.2	10.3	9.6	8.3
Hydroelectric	47	47	50	.7	.1	.1	.1
Other Renewables	0	3	5	NM	.0	.0	.0
Total Electric Utilities	**34,814**	**36,727**	**40,313**	**1.6**	**93.5**	**91.0**	**85.7**
Coal	235	734	806	14.7	.6	1.8	1.7
Petroleum	66	58	18	−13.5	.2	.1	.0
Natural Gas	334	798	521	5.0	.9	2.0	1.1
Dual Fired	545	608	4,043	24.9	1.5	1.5	8.6
Other Renewables	875	1,080	962	1.1	2.4	2.7	2.0
Other	347	347	391	1.3	.9	.9	.8
Total IPP's & Combined Heat and Power	**2,402**	**3,624**	**6,740**	**12.1**	**6.5**	**9.0**	**14.3**
Coal	10,266	11,557	12,107	1.9	27.6	28.6	25.7
Petroleum	5,634	5,750	4,912	−1.5	15.1	14.3	10.4
Natural Gas	3,004	4,313	4,091	3.5	8.1	10.7	8.7
Dual Fired	13,219	13,378	20,630	5.1	35.5	33.2	43.8
Nuclear	3,826	3,876	3,906	.2	10.3	9.6	8.3
Hydroelectric	47	47	50	.7	.1	.1	.1
Other Renewables	875	1,083	967	1.1	2.4	2.7	2.1
Other	347	347	391	1.3	.9	.9	.8
Total Electric Industry	**37,216**	**40,351**	**47,054**	**2.6**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Florida							
Coal	61,889,050	66,034,628	60,997,142	-0.2	40.7	39.2	30.0
Petroleum	34,277,523	25,742,149	32,449,236	-.6	22.6	15.3	16.0
Natural Gas	17,802,730	32,997,876	54,883,087	13.3	11.7	19.6	27.0
Nuclear	25,886,864	22,967,743	33,704,230	3.0	17.0	13.7	16.6
Hydroelectric	210,776	241,280	184,114	-1.5	.1	.1	.1
Other Renewables	0	0	128,820	NM	.0	.0	.1
Total Electric Utilities	**140,066,943**	**147,983,676**	**182,346,629**	**3.0**	**92.2**	**88.0**	**89.7**
Coal	1,249,624	4,899,877	4,929,251	16.5	.8	2.9	2.4
Petroleum	449,569	417,573	1,232,115	11.9	.3	.2	.6
Natural Gas	2,952,072	6,877,808	8,280,948	12.1	1.9	4.1	4.1
Other Gases	72,413	56,209	13,079	-17.3	.0	.0	.0
Other Renewables	5,466,581	5,953,025	5,014,581	-1.0	3.6	3.5	2.5
Other	1,676,955	2,058,826	1,536,172	-1.0	1.1	1.2	.8
Total IPP's & Combined Heat and Power	**11,867,212**	**20,263,318**	**21,006,146**	**6.6**	**7.8**	**12.0**	**10.3**
Coal	63,138,674	70,934,505	65,926,393	.5	41.6	42.2	32.4
Petroleum	34,727,092	26,159,722	33,681,351	-.3	22.9	15.5	16.6
Natural Gas	20,754,802	39,875,684	63,164,035	13.2	13.7	23.7	31.1
Other Gases	72,413	56,209	13,079	-17.3	.0	.0	.0
Nuclear	25,886,864	22,967,743	33,704,230	3.0	17.0	13.7	16.6
Hydroelectric	210,776	241,280	184,114	-1.5	.1	.1	.1
Other Renewables	5,466,581	5,953,025	5,143,401	-.7	3.6	3.5	2.5
Other	1,676,955	2,058,826	1,536,172	-1.0	1.1	1.2	.8
Total Electric Industry	**151,934,155**	**168,246,994**	**203,352,775**	**3.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Florida				
Coal (2002 cents per million Btu)	197.0	177.3	176.2	-1.2
Average heat value (Btu per pound)	12,332	12,122	12,247	-.1
Average sulfur Content(percent)	1.6	1.6	1.5	-.1
Petroleum (2002 cents per million Btu)	245.4	260.9	324.0	3.1
Average heat value (Btu per gallon)	151,661	143,488	147,664	-.3
Average sulfur Content(percent)	1.5	1.9	1.8	1.9
Gas (2002 cents per million Btu)	260.9	312.7	396.7	4.8
Average heat value (Btu per cubic foot)	1,009	1,044	1,026	.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Florida				
Sulfur Dioxide				
Coal	463	472	303	-4.6
Petroleum	259	231	190	-3.3
Gas	*	*	*	.0
Other	12	14	8	-4.9
Total	734	717	501	-4.2
Nitrogen Oxide				
Coal	239	220	188	-2.6
Petroleum	47	57	57	2.1
Gas	34	42	37	.8
Other	8	10	9	.8
Total	328	328	289	-1.4
Carbon Dioxide				
Coal	63,399	72,577	68,578	.9
Petroleum	29,487	23,402	30,160	.3
Gas	11,741	21,393	32,013	11.8
Other	632	684	731	1.6
Total	105,259	118,055	131,482	2.5

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Florida							
Retail Sales (thousand megawatthours)							
Residential	76,827	87,845	108,164	3.9	50.3	50.2	51.4
Commercial	54,876	63,337	77,561	3.9	35.9	36.2	36.8
Industrial	16,298	18,266	18,959	1.7	10.7	10.4	9.0
Other	4,747	5,593	5,789	2.2	3.1	3.2	2.8
Total	152,748	175,041	210,474	3.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	6,836	7,293	8,823	2.9	55.8	56.4	57.3
Commercial	4,087	4,306	5,150	2.6	33.4	33.3	33.5
Industrial	955	945	991	.4	7.8	7.3	6.4
Other	368	391	430	1.8	3.0	3.0	2.8
Total	12,247	12,936	15,394	2.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.90	8.30	8.16	-1.0	NA	NA	NA
Commercial	7.45	6.80	6.64	-1.3	NA	NA	NA
Industrial	5.86	5.18	5.23	-1.3	NA	NA	NA
Other	7.75	6.99	7.43	-.5	NA	NA	NA
Total	8.02	7.39	7.31	-1.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Florida						
Number of Entities	5	32	0	16	0	53
Number of Retail Customers	6,493,560	1,178,945	0	860,774	0	8,533,279
Retail Sales (thousand megawatthours)	161,843	32,987	.0	15,644	0	210,474
Percentage of Retail Sales	76.89	15.67	.00	7.43	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	11,941	2,266	0	1,186	0	15,394
Percentage of Revenue	77.57	14.72	.00	7.71	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.38	6.87	.00	7.58	0	7.31

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Georgia		
NERC Region(s)		SERC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	34,601	7
Electric Utilities	25,821	4
Independent Power Producers & Combined Heat and Power	8,780	10
Net Generation (megawatthours)	126,512,216	9
Electric Utilities	111,855,967	7
Independent Power Producers & Combined Heat and Power	14,656,249	16
Emissions (thousand short tons)		
Sulfur Dioxide	566	5
Nitrogen Oxide	165	10
Carbon Dioxide	83,943	10
Sulfur Dioxide/sq. mile	10	11
Nitrogen Oxide/sq. mile	3	17
Carbon Dioxide/sq. mile	1,449	18
Utility and ESP Retail Electricity Sales (megawatthours)	123,789,078	8
Utility Retail Electricity Sales (megawatthours)	123,789,078	7
Direct Use (megawatthours)	5,455,994	8
Average Retail Price (cents/kWh)	6.24	28

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Georgia			
1. Scherer	Petroleum, Coal	Georgia Power Co	3,430
2. Bowen	Petroleum, Coal	Georgia Power Co	3,294
3. Wansley	Petroleum, Coal	Georgia Power Co	2,805
4. Vogtle	Nuclear	Georgia Power Co	2,297
5. Edwin I Hatch	Nuclear	Georgia Power Co	1,726
6. Harllee Branch	Petroleum, Coal	Georgia Power Co	1,607
7. Yates	Petroleum, Gas, Coal	Georgia Power Co	1,295
8. Murray Energy Facilit	Gas	Duke Energy North Amer-Murray	1,244
9. Wansley	Gas	Southern Power Co	973
10. Tenaska Georgia Gener	Petroleum, Gas	Tenaska Georgia Partners LP	933

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Georgia					
A. Georgia Power Company	75,432,469	22,144,559	26,954,922	25,739,785	593,203
B. Savannah Electric & Power Co	4,203,626	1,793,330	1,477,224	793,181	139,891
C. Jackson Electric Member Corp	3,823,910	2,205,407	986,068	489,439	142,996
D. Cobb Electric Membership Corp	3,362,087	2,120,993	908,281	197,389	135,424
E. North Georgia Elec Member Corp	2,550,739	1,358,670	443,663	729,134	19,272
Total	89,372,831	29,622,959	30,770,158	27,948,928	1,030,786
Percentage of Utility Sales	72	61	79	81	61

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Georgia							
Coal	13,115	13,222	13,498	0.3	58.2	53.2	39.0
Petroleum	1,057	1,061	991	–.7	4.7	4.3	2.9
Natural Gas	33	33	2,315	60.3	.1	.1	6.7
Dual Fired	622	1,415	1,225	7.8	2.8	5.7	3.5
Nuclear	3,825	3,955	4,023	.6	17.0	15.9	11.6
Hydroelectric	2,853	3,461	3,769	3.1	12.7	13.9	10.9
Total Electric Utilities	**21,504**	**23,147**	**25,821**	**2.1**	**95.5**	**93.1**	**74.6**
Coal	64	51	317	19.4	.3	.2	.9
Petroleum	150	185	253	6.0	.7	.7	.7
Natural Gas	23	161	4,185	78.5	.1	.6	12.1
Dual Fired	87	582	3,613	51.3	.4	2.3	10.4
Hydroelectric	13	14	10	–3.0	.1	.1	.0
Other Renewables	679	715	402	–5.6	3.0	2.9	1.2
Total IPP's & Combined Heat and Power	**1,015**	**1,707**	**8,780**	**27.1**	**4.5**	**6.9**	**25.4**
Coal	13,179	13,273	13,815	.5	58.5	53.4	39.9
Petroleum	1,206	1,246	1,243	.3	5.4	5.0	3.6
Natural Gas	56	194	6,500	69.6	.2	.8	18.8
Dual Fired	710	1,997	4,838	23.8	3.2	8.0	14.0
Nuclear	3,825	3,955	4,023	.6	17.0	15.9	11.6
Hydroelectric	2,865	3,474	3,779	3.1	12.7	14.0	10.9
Other Renewables	679	715	402	–5.6	3.0	2.9	1.2
Total Electric Industry	**22,519**	**24,854**	**34,601**	**4.9**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Georgia							
Coal	63,295,811	66,179,551	77,288,328	2.2	62.4	61.5	61.1
Petroleum	237,473	200,873	233,940	–.2	.2	.2	.2
Natural Gas	218,218	567,727	1,189,392	20.7	.2	.5	.9
Nuclear	27,233,352	30,414,494	31,107,735	1.5	26.8	28.3	24.6
Hydroelectric	4,752,651	4,417,788	2,036,572	–9.0	4.7	4.1	1.6
Total Electric Utilities	**95,737,505**	**101,780,433**	**111,855,967**	**1.7**	**94.4**	**94.6**	**88.4**
Coal	956,755	996,020	1,539,796	5.4	.9	.9	1.2
Petroleum	900,439	730,296	970,625	.8	.9	.7	.8
Natural Gas	477,995	648,381	5,699,758	31.7	.5	.6	4.5
Hydroelectric	48,444	51,420	30,982	–4.8	.0	.0	.0
Other Renewables	3,326,431	3,415,216	6,415,087	7.6	3.3	3.2	5.1
Other	0	4,194	0	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**5,710,064**	**5,845,526**	**14,656,249**	**11.0**	**5.6**	**5.4**	**11.6**
Coal	64,252,566	67,175,571	78,828,124	2.3	63.3	62.4	62.3
Petroleum	1,137,912	931,169	1,204,565	.6	1.1	.9	1.0
Natural Gas	696,213	1,216,108	6,889,150	29.0	.7	1.1	5.4
Nuclear	27,233,352	30,414,494	31,107,735	1.5	26.8	28.3	24.6
Hydroelectric	4,801,095	4,469,208	2,067,554	–8.9	4.7	4.2	1.6
Other Renewables	3,326,431	3,415,216	6,415,087	7.6	3.3	3.2	5.1
Other	0	4,194	0	NM	.0	.0	.0
Total Electric Industry	**101,447,569**	**107,625,959**	**126,512,216**	**2.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Georgia				
Coal (2002 cents per million Btu)	198.6	163.0	167.7	–1.9
Average heat value (Btu per pound)	12,148	11,755	11,698	–.4
Average sulfur Content(percent)	1.4	.8	.8	–6.0
Petroleum (2002 cents per million Btu)	386.7	432.5	548.6	4.0
Average heat value (Btu per gallon)	142,391	140,473	140,850	–.1
Average sulfur Content(percent)	1.2	.5	.4	–11.8
Gas (2002 cents per million Btu)	360.8	272.8	362.3	*
Average heat value (Btu per cubic foot)	1,023	1,024	1,022	.0

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Georgia				
Sulfur Dioxide				
Coal	696	519	524	-3.1
Petroleum	4	7	24	23.0
Gas	0	0	*	NM
Other	12	10	18	4.5
Total	712	535	566	-2.5
Nitrogen Oxide				
Coal	186	183	152	-2.2
Petroleum	2	2	2	-.5
Gas	1	2	5	23.3
Other	4	3	5	4.4
Total	193	189	165	-1.8
Carbon Dioxide				
Coal	63,347	73,610	78,752	2.4
Petroleum	1,485	1,076	1,149	-2.8
Gas	449	1,185	4,041	27.6
Other	0	3	1	NM
Total	65,281	75,874	83,943	2.8

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Georgia							
Retail Sales (thousand megawatthours)							
Residential	33,867	36,831	48,600	4.1	38.0	36.0	39.3
Commercial	25,169	30,200	38,887	4.9	28.2	29.5	31.4
Industrial	29,084	33,957	34,603	1.9	32.6	33.2	27.9
Other	1,071	1,262	1,699	5.3	1.2	1.2	1.4
Total	89,191	102,250	123,789	3.7	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	2,940	2,931	3,706	2.6	44.1	43.8	48.0
Commercial	2,087	2,207	2,513	2.1	31.3	33.0	32.5
Industrial	1,536	1,441	1,366	-1.3	23.0	21.5	17.7
Other	101	117	141	3.8	1.5	1.8	1.8
Total	6,664	6,695	7,726	1.7	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.68	7.96	7.63	-1.4	NA	NA	NA
Commercial	8.29	7.31	6.46	-2.7	NA	NA	NA
Industrial	5.28	4.24	3.95	-3.2	NA	NA	NA
Other	9.47	9.30	8.31	-1.4	NA	NA	NA
Total	7.47	6.55	6.24	-2.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Georgia						
Number of Entities	2	55	0	41	0	98
Number of Retail Customers	2,115,664	374,809	0	1,581,011	0	4,071,484
Retail Sales (thousand megawatthours)	79,636	12,342	0	31,811	0	123,789
Percentage of Retail Sales	64.33	9.97	.00	25.70	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	4,574	807	0	2,344	0	7,726
Percentage of Revenue	59.20	10.45	.00	30.35	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.74	6.54	.00	7.37	0	6.24

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Hawaii		
NERC Region(s)		–
Primary Energy Source		Petroleum
Net Summer Capability (megawatts)	2,267	47
Electric Utilities	1,622	41
Independent Power Producers & Combined Heat and Power	645	42
Net Generation (megawatthours)	11,663,069	44
Electric Utilities	7,513,051	40
Independent Power Producers & Combined Heat and Power	4,150,018	33
Emissions (thousand short tons)		
Sulfur Dioxide	29	41
Nitrogen Oxide	15	41
Carbon Dioxide	9,028	41
Sulfur Dioxide/sq. mile	4	22
Nitrogen Oxide/sq. mile	2	21
Carbon Dioxide/sq. mile	1,406	19
Utility and ESP Retail Electricity Sales (megawatthours)	9,891,638	46
Utility Retail Electricity Sales (megawatthours)	9,891,638	45
Direct Use (megawatthours)	521,088	28
Average Retail Price (cents/kWh)	13.39	1

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Hawaii			
1. Kahe	Petroleum	Hawaiian Electric Co Inc	582
2. Waiau	Petroleum	Hawaiian Electric Co Inc	457
3. Maalaea	Petroleum	Maui Electric Co Ltd	190
4. AES Hawaii	Petroleum, Other, Coal	AES Hawaii Inc	180
5. Kalaeola Cogen Plant	Petroleum	Kalaeloa Partners LP	180
6. Honolulu	Petroleum	Hawaiian Electric Co Inc	100
7. Port Allen	Petroleum	Citizens Utilities Co	96
8. Hamakua Energy Plant	Other	Hamakua Energy Partners LP	61
9. H Power	Other	DFO Partnership	60
10. HC & S - Puunene Fact	Petroleum, Hydro, Coal	Hawaiian Com & Sugar Co Ltd	46

See footnotes at end of tables.

Table 3. Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Hawaii					
A. Hawaiian Electric Company, Inc	7,390,367	2,002,655	2,309,597	3,034,903	43,212
B. Maui Electric Company, Ltd	1,158,717	398,871	372,076	382,093	5,677
C. Hawaii Electric Light Co, Inc	995,198	377,022	391,901	222,161	4,114
D. Citizens Communications Co	347,356	119,832	94,359	131,244	1,921
Total	9,891,638	2,898,380	3,167,933	3,770,401	54,924
Percentage of Utility Sales	100	100	100	100	100

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Hawaii							
Petroleum	1,598	1,574	1,618	0.1	67.4	67.3	71.4
Natural Gas	0	18	0	NM	.0	.8	.0
Hydroelectric	3	3	2	-7.3	.1	.1	.1
Other Renewables	0	0	2	NM	.0	.0	.1
Total Electric Utilities	1,602	1,595	1,622	.1	67.5	68.3	71.6
Coal	213	213	202	-.6	9.0	9.1	8.9
Petroleum	275	275	197	-3.7	11.6	11.8	8.7
Natural Gas	0	0	67	NM	.0	.0	3.0
Other Gases	8	8	9	1.8	.3	.3	.4
Hydroelectric	14	25	22	4.8	.6	1.1	1.0
Other Renewables	259	221	148	-6.1	10.9	9.4	6.5
Total IPP's & Combined Heat and Power	770	742	645	-2.0	32.5	31.7	28.4
Coal	213	213	202	-.6	9.0	9.1	8.9
Petroleum	1,874	1,849	1,815	-.4	79.0	79.1	80.1
Natural Gas	0	18	67	NM	.0	.8	3.0
Other Gases	8	8	9	1.8	.3	.3	.4
Hydroelectric	18	28	23	3.2	.7	1.2	1.0
Other Renewables	259	221	150	-5.9	10.9	9.4	6.6
Total Electric Industry	2,372	2,337	2,267	-.5	100.0	100.0	100.0

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Hawaii							
Petroleum	6,070,063	6,193,852	7,502,913	2.4	61.0	60.1	64.3
Hydroelectric	13,752	18,791	8,533	-5.2	.1	.2	.1
Other Renewables	0	0	1,605	NM	.0	.0	.0
Total Electric Utilities	6,083,815	6,212,643	7,513,051	2.4	61.2	60.2	64.4
Coal	1,479,075	1,574,731	1,545,797	.5	14.9	15.3	13.3
Petroleum	1,323,918	1,495,288	1,964,077	4.5	13.3	14.5	16.8
Other Gases	63,068	65,383	40,816	-4.7	.6	.6	.3
Hydroelectric	42,491	96,540	86,535	8.2	.4	.9	.7
Other Renewables	951,321	867,663	512,794	-6.6	9.6	8.4	4.4
Total IPP's & Combined Heat and Power	3,859,872	4,099,604	4,150,018	.8	38.8	39.8	35.6
Coal	1,479,075	1,574,731	1,545,797	.5	14.9	15.3	13.3
Petroleum	7,393,981	7,689,140	9,466,990	2.8	74.4	74.6	81.2
Other Gases	63,068	65,383	40,816	-4.7	.6	.6	.3
Hydroelectric	56,243	115,331	95,068	6.0	.6	1.1	.8
Other Renewables	951,321	867,663	514,399	-6.6	9.6	8.4	4.4
Total Electric Industry	9,943,687	10,312,247	11,663,069	1.8	100.0	100.0	100.0

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Hawaii				
Coal (2002 cents per million Btu)	0.0	0.0	303.4	NM
Average heat value (Btu per pound)	0	0	11,454	NM
Average sulfur Content(percent)	.0	.0	.3	NM
Petroleum (2002 cents per million Btu)	344.0	374.4	491.8	4.0
Average heat value (Btu per gallon)	149,195	149,351	142,633	-.5
Average sulfur Content(percent)	.4	.4	.4	.3

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Hawaii				
Sulfur Dioxide				
Coal	3	4	7	10.1
Petroleum	20	27	22	.9
Other	*	*	*	10.5
Total	23	31	29	2.4
Nitrogen Oxide				
Coal	5	7	3	-4.5
Petroleum	9	9	11	2.4
Gas	*	*	*	-14.3
Other	1	1	1	.9
Total	15	17	15	.1
Carbon Dioxide				
Coal	1,374	1,682	1,698	2.4
Petroleum	6,512	6,840	7,253	1.2
Gas	74	44	23	-12.2
Other	76	68	54	-3.8
Total	8,036	8,634	9,028	1.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Hawaii							
Retail Sales (thousand megawatthours)							
Residential	2,469	2,668	2,898	1.8	28.5	28.5	29.3
Commercial	2,363	2,782	3,168	3.3	27.3	29.7	32.0
Industrial	3,770	3,856	3,770	.0	43.5	41.2	38.1
Other	56	57	55	–.3	.6	.6	.6
Total	8,658	9,363	9,892	1.5	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	338	406	453	3.3	32.8	33.8	34.2
Commercial	308	379	447	4.2	29.9	31.5	33.7
Industrial	376	409	415	1.1	36.5	34.0	31.4
Other	7	8	9	3.1	.7	.6	.7
Total	1,028	1,202	1,325	2.9	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	13.68	15.21	15.63	1.5	NA	NA	NA
Commercial	13.01	13.63	14.11	.9	NA	NA	NA
Industrial	9.97	10.61	11.02	1.1	NA	NA	NA
Other	12.55	13.56	16.85	3.3	NA	NA	NA
Total	11.87	12.83	13.39	1.3	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Hawaii						
Number of Entities	3	1	0	0	0	4
Number of Retail Customers	408,605	26,203	0	0	0	434,808
Retail Sales (thousand megawatthours)	9,544	347	0	0	0	9,892
Percentage of Retail Sales	96.49	3.51	.00	.00	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,248	77	0	0	0	1,325
Percentage of Revenue	94.22	5.78	.00	.00	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	13.08	22.06	.00	.00	0	13.39

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Idaho		
NERC Region(s)		WSCC
Primary Energy Source		Hydro
Net Summer Capability (megawatts)	3,264	45
Electric Utilities	2,690	38
Independent Power Producers & Combined Heat and Power	574	43
Net Generation (megawatthours)	9,786,933	45
Electric Utilities	8,164,140	38
Independent Power Producers & Combined Heat and Power	1,622,793	41
Emissions (thousand short tons)		
Sulfur Dioxide	5	47
Nitrogen Oxide	2	48
Carbon Dioxide	809	49
Sulfur Dioxide/sq. mile	0	49
Nitrogen Oxide/sq. mile	0	50
Carbon Dioxide/sq. mile	10	49
Utility and ESP Retail Electricity Sales (megawatthours)	20,699,666	38
Utility Retail Electricity Sales (megawatthours)	20,699,666	38
Direct Use (megawatthours)	120,331	39
Average Retail Price (cents/kWh)	5.58	44

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Idaho			
1. Brownlee	Hydro	Idaho Power Co	728
2. Dworshak	Hydro	USCE-North Pacific Division	460
3. Cabinet Gorge	Hydro	Avista Corporation	272
4. Rathdrum Power LLC	Gas	Rathdrum Operating Services Co.	248
5. Palisades	Hydro	U S Bureau of Reclamation	176
6. Rathdrum	Gas	Avista Corporation	136
7. C J Strike	Hydro	Idaho Power Co	88
8. American Falls	Hydro	Idaho Power Co	86
9. Mountain Home	Gas	Idaho Power Co	76
10. Bliss	Hydro	Idaho Power Co	75

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Idaho					
A. Idaho Power Company	12,265,349	4,197,803	5,057,033	2,982,939	27,574
B. PacifiCorp	3,225,369	582,967	354,840	2,285,481	2,081
C. Avista Corporation	2,600,246	1,010,456	881,248	699,502	9,040
D. Idaho Falls Power	623,863	282,632	253,003	45,909	42,319
E. Kootenai Electric Coop, Inc	289,952	200,128	76,804	9,012	4,008
Total	19,004,779	6,273,986	6,622,928	6,022,843	85,022
Percentage of Utility Sales	92	89	95	95	26

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Idaho							
Petroleum	6	6	5	–0.2	0.2	0.2	0.2
Natural Gas	0	136	212	NM	.0	4.5	6.5
Hydroelectric	2,299	2,435	2,472	.8	84.9	80.9	75.7
Total Electric Utilities	**2,304**	**2,576**	**2,690**	**1.7**	**85.1**	**85.6**	**82.4**
Coal	12	18	16	3.3	.5	.6	.5
Natural Gas	0	18	269	NM	.0	.6	8.2
Hydroelectric	247	253	193	–2.7	9.1	8.4	5.9
Other Renewables	130	130	81	–5.1	4.8	4.3	2.5
Other	15	15	15	.0	.5	.5	.5
Total IPP's & Combined Heat and Power	**404**	**434**	**574**	**4.0**	**14.9**	**14.4**	**17.6**
Coal	12	18	16	3.3	.5	.6	.5
Petroleum	6	6	5	–.2	.2	.2	.2
Natural Gas	0	154	481	NM	.0	5.1	14.7
Hydroelectric	2,546	2,688	2,665	.5	94.0	89.3	81.7
Other Renewables	130	130	81	–5.1	4.8	4.3	2.5
Other	15	15	15	.0	.5	.5	.5
Total Electric Industry	**2,708**	**3,011**	**3,264**	**2.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Idaho							
Petroleum	103	95	65	–5.0	0.0	0.0	0.0
Natural Gas	0	0	76,168	NM	.0	.0	.8
Hydroelectric	9,022,551	13,511,728	8,087,907	–1.2	85.7	86.7	82.6
Total Electric Utilities	**9,022,654**	**13,511,823**	**8,164,140**	**–1.1**	**85.7**	**86.7**	**83.4**
Coal	39,299	27,462	90,673	9.7	.4	.2	.9
Petroleum	329	11,651	0	NM	.0	.1	.0
Natural Gas	156,736	312,988	252,820	5.5	1.5	2.0	2.6
Hydroelectric	692,934	1,163,899	681,414	–.2	6.6	7.5	7.0
Other Renewables	546,637	471,238	508,303	–.8	5.2	3.0	5.2
Other	74,844	89,950	89,583	2.0	.7	.6	.9
Total IPP's & Combined Heat and Power	**1,510,779**	**2,077,187**	**1,622,793**	**.8**	**14.3**	**13.3**	**16.6**
Coal	39,299	27,462	90,673	9.7	.4	.2	.9
Petroleum	432	11,746	65	–19.0	.0	.1	.0
Natural Gas	156,736	312,988	328,988	8.6	1.5	2.0	3.4
Hydroelectric	9,715,485	14,675,627	8,769,321	–1.1	92.2	94.1	89.6
Other Renewables	546,637	471,238	508,303	–.8	5.2	3.0	5.2
Other	74,844	89,950	89,583	2.0	.7	.6	.9
Total Electric Industry	**10,533,433**	**15,589,010**	**9,786,933**	**–.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Idaho				
Average heat value (Btu per pound)	0	0	11,041	NM
Average heat value (Btu per gallon)	0	0	138,660	NM
Gas (2002 cents per million Btu)	.0	.0	298.1	NM
Average heat value (Btu per cubic foot)	0	0	1,003	NM

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Idaho				
Sulfur Dioxide				
Coal	1	1	3	7.1
Petroleum	0	*	0	NM
Gas	0	0	0	NM
Other	1	1	2	9.3
Total	2	2	5	8.1
Nitrogen Oxide				
Coal	*	*	1	7.7
Petroleum	0	*	0	NM
Gas	*	*	1	13.0
Other	*	*	1	6.6
Total	1	1	2	8.6
Carbon Dioxide				
Coal	75	39	129	6.3
Petroleum	*	9	*	-15.5
Gas	101	185	680	23.6
Total	176	233	809	18.4

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Idaho							
Retail Sales (thousand megawatthours)							
Residential	6,245	6,628	7,056	1.4	33.4	31.2	34.1
Commercial	4,969	5,969	6,963	3.8	26.5	28.1	33.6
Industrial	7,222	8,322	6,352	-1.4	38.6	39.2	30.7
Other	284	316	329	1.6	1.5	1.5	1.6
Total	18,720	21,235	20,700	1.1	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	347	351	465	3.3	41.7	41.6	40.2
Commercial	244	256	398	5.6	29.3	30.3	34.4
Industrial	226	222	276	2.2	27.1	26.3	23.9
Other	16	15	17	.8	1.9	1.8	1.5
Total	834	844	1,156	3.7	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	5.56	5.29	6.59	1.9	NA	NA	NA
Commercial	4.92	4.28	5.71	1.7	NA	NA	NA
Industrial	3.13	2.67	4.34	3.7	NA	NA	NA
Other	5.56	4.81	5.18	-.8	NA	NA	NA
Total	4.45	3.97	5.58	2.5	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Idaho						
Number of Entities	3	12	0	16	0	31
Number of Retail Customers	501,458	97,338	0	69,259	0	668,055
Retail Sales (thousand megawatthours)	14,866	4,276	0	1,558	0	20,700
Percentage of Retail Sales	71.82	20.66	.00	7.52	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	899	161	0	95	0	1,156
Percentage of Revenue	77.83	13.97	.00	8.20	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.05	3.78	.00	6.08	0	5.58

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Illinois		
NERC Region(s)		MAIN/MAPP
Primary Energy Source		Nuclear
Net Summer Capability (megawatts)	44,712	4
Electric Utilities	4,150	36
Independent Power Producers & Combined Heat and Power	40,561	2
Net Generation (megawatthours)	188,054,449	4
Electric Utilities	17,149,913	36
Independent Power Producers & Combined Heat and Power	170,904,536	3
Emissions (thousand short tons)		
Sulfur Dioxide	405	11
Nitrogen Oxide	191	8
Carbon Dioxide	101,237	6
Sulfur Dioxide/sq. mile	7	15
Nitrogen Oxide/sq. mile	3	14
Carbon Dioxide/sq. mile	1,821	14
Utility and ESP Retail Electricity Sales (megawatthours)	137,665,583	7
Utility Retail Electricity Sales (megawatthours)	121,879,478	9
ESP Retail Electricity Sales (megawatthours)	15,786,105	4
Direct Use (megawatthours)	1,704,013	21
Average Retail Price (cents/kWh)	6.97	18

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Illinois			
1. Collins	Petroleum, Gas	Midwest Generations EME LLC	2,671
2. Braidwood Generation	Nuclear	Exelon Generation Co LLC	2,362
3. Byron Generating Stat	Nuclear	Exelon Generation Co LLC	2,356
4. LaSalle Generating St	Nuclear	Exelon Generation Co LLC	2,260
5. Baldwin Energy Comple	Petroleum, Other, Coal	Dynegy Midwest Generation Inc	1,761
6. Dresden Generating St	Nuclear	Exelon Generation Co LLC	1,700
7. Quad Cities Generatin	Nuclear	Exelon Generation Co LLC	1,617
8. Powerton	Gas, Coal	Midwest Generations EME LLC	1,538
9. Elwood Energy LLC	Gas	Dominion Elwood Services Co	1,350
10. Kincaid Generation LL	Gas, Coal	Dominion Energy Services Co	1,168

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Illinois					
A. Commonwealth Edison Company	73,835,297	27,474,341	25,517,175	13,016,569	7,827,212
B. Illinois Power Company	16,637,617	5,548,382	4,415,749	6,305,777	367,709
C. Central Illinois Pub Serv Co	10,468,874	3,154,750	2,771,546	4,397,805	144,773
D. Central Illinois Light Company	9,023,123	1,993,346	1,819,814	2,278,858	2,931,105
E. Exelon Energy Company	4,022,967	0	4,022,967	0	0
Total	113,987,878	38,170,819	38,547,251	25,999,009	11,270,799
Percentage of Utility Sales	83	85	86	73	95

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Illinois							
Coal	15,063	15,339	2,862	-16.9	45.1	44.5	6.4
Petroleum	2,630	2,314	297	-21.5	7.9	6.7	.7
Natural Gas	1,982	2,602	387	-16.6	5.9	7.5	.9
Dual Fired	472	673	593	2.6	1.4	2.0	1.3
Nuclear	12,609	12,609	0	NM	37.7	36.6	.0
Hydroelectric	12	13	12	-.4	.0	.0	.0
Total Electric Utilities	**32,769**	**33,549**	**4,151**	**-20.5**	**98.1**	**97.3**	**9.3**
Coal	328	393	12,792	50.2	1.0	1.1	28.6
Petroleum	8	7	998	72.0	.0	.0	2.2
Natural Gas	169	275	11,495	59.8	.5	.8	25.7
Other Gases	55	45	40	-3.6	.2	.1	.1
Dual Fired	36	54	3,763	67.4	.1	.2	8.4
Nuclear	0	0	11,312	NM	.0	.0	25.3
Hydroelectric	18	21	9	-7.4	.1	.1	.0
Other Renewables	32	135	154	19.2	.1	.4	.3
Total IPP's & Combined Heat and Power	**646**	**929**	**40,561**	**58.4**	**1.9**	**2.7**	**90.7**
Coal	15,391	15,732	15,654	.2	46.1	45.6	35.0
Petroleum	2,638	2,320	1,295	-7.6	7.9	6.7	2.9
Natural Gas	2,151	2,877	11,881	20.9	6.4	8.3	26.6
Other Gases	55	45	40	-3.6	.2	.1	.1
Dual Fired	509	727	4,356	26.9	1.5	2.1	9.7
Nuclear	12,609	12,609	11,312	-1.2	37.7	36.6	25.3
Hydroelectric	30	34	21	-4.0	.1	.1	.0
Other Renewables	32	135	154	19.2	.1	.4	.3
Total Electric Industry	**33,415**	**34,478**	**44,712**	**3.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Illinois							
Coal	59,764,568	76,091,528	16,897,445	-13.1	41.7	56.3	9.0
Petroleum	719,130	495,250	34,464	-28.6	.5	.4	.0
Natural Gas	1,184,217	3,442,363	161,134	-19.9	.8	2.5	.1
Nuclear	78,373,458	51,068,818	0	NM	54.6	37.8	.0
Hydroelectric	39,647	16,773	56,870	4.1	.0	.0	.0
Other Renewables	0	23,595	0	NM	.0	.0	.0
Total Electric Utilities	**140,081,020**	**131,138,327**	**17,149,913**	**-20.8**	**97.6**	**97.0**	**9.1**
Coal	1,725,747	2,029,739	69,787,902	50.8	1.2	1.5	37.1
Petroleum	14,962	32,672	188,219	32.5	.0	.0	.1
Natural Gas	942,393	840,242	8,917,601	28.4	.7	.6	4.7
Other Gases	347,139	361,119	232,850	-4.3	.2	.3	.1
Nuclear	0	0	90,860,108	NM	.0	.0	48.3
Hydroelectric	90,548	80,401	71,952	-2.5	.1	.1	.0
Other Renewables	251,281	658,269	845,361	14.4	.2	.5	.4
Other	0	0	543	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**3,372,071**	**4,002,442**	**170,904,536**	**54.7**	**2.4**	**3.0**	**90.9**
Coal	61,490,315	78,121,267	86,685,347	3.9	42.9	57.8	46.1
Petroleum	734,092	527,922	222,683	-12.4	.5	.4	.1
Natural Gas	2,126,610	4,282,605	9,078,735	17.5	1.5	3.2	4.8
Other Gases	347,139	361,119	232,850	-4.3	.2	.3	.1
Nuclear	78,373,458	51,068,818	90,860,108	1.7	54.6	37.8	48.3
Hydroelectric	130,195	97,174	128,822	-.1	.1	.1	.1
Other Renewables	251,281	681,864	845,361	14.4	.2	.5	.4
Other	0	0	543	NM	.0	.0	.0
Total Electric Industry	**143,453,091**	**135,140,769**	**188,054,449**	**3.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Illinois				
Coal (2002 cents per million Btu)	189.9	159.8	118.5	-5.1
Average heat value (Btu per pound)	10,362	9,781	9,151	-1.4
Average sulfur Content(percent)	1.6	1.2	.7	-9.0
Petroleum (2002 cents per million Btu)	331.0	317.6	524.5	5.2
Average heat value (Btu per gallon)	148,695	126,779	146,974	-.1
Average sulfur Content(percent)	.7	2.1	.1	-16.1
Gas (2002 cents per million Btu)	272.5	258.3	342.7	2.6
Average heat value (Btu per cubic foot)	1,016	1,016	988	-.3

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Illinois				
Sulfur Dioxide				
Coal	823	840	403	-7.6
Petroleum	4	2	1	-15.0
Gas	0	0	*	NM
Other	*	*	1	34.0
Total	828	842	405	-7.6
Nitrogen Oxide				
Coal	307	316	180	-5.8
Petroleum	1	1	*	-20.2
Gas	5	6	6	1.1
Other	1	2	4	14.3
Total	315	325	191	-5.4
Carbon Dioxide				
Coal	69,840	86,587	95,743	3.6
Petroleum	1,120	597	225	-16.3
Gas	1,731	3,270	5,269	13.2
Other	*	30	0	NM
Total	72,692	90,483	101,237	3.8

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Illinois							
Retail Sales (thousand megawatthours)							
Residential	35,226	37,246	45,030	2.8	29.9	29.5	32.7
Commercial	34,355	38,136	44,957	3.0	29.2	30.2	32.7
Industrial	40,249	42,375	35,802	-1.3	34.2	33.5	26.0
Other	7,956	8,692	11,876	4.5	6.8	6.9	8.6
Total	117,786	126,449	137,666	1.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	4,034	3,994	3,778	-.7	39.7	39.9	39.4
Commercial	3,062	3,107	3,367	1.1	30.1	31.0	35.1
Industrial	2,443	2,305	1,792	-3.4	24.0	23.0	18.7
Other	623	611	660	.6	6.1	6.1	6.9
Total	10,162	10,016	9,597	-.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	11.45	10.72	8.39	-3.4	NA	NA	NA
Commercial	8.91	8.15	7.49	-1.9	NA	NA	NA
Industrial	6.07	5.44	5.01	-2.1	NA	NA	NA
Other	7.83	7.03	5.56	-3.7	NA	NA	NA
Total	8.63	7.92	6.97	-2.3	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Illinois						
Number of Entities	7	43	0	27	10	87
Number of Retail Customers	4,792,092	346,388	0	255,106	10,655	5,404,241
Retail Sales (thousand megawatthours)	108,511	8,769	0	4,600	15,786	137,666
Percentage of Retail Sales	78.82	6.37	.00	3.34	11.47	100.00
Revenue from Retail Sales (million 2002 dollars)	7,924	552	0	406	715	9,597
Percentage of Revenue	82.57	5.75	.00	4.23	7.45	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.30	6.29	.00	8.82	0	6.97

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Indiana		
NERC Region(s)		ECAR
Primary Energy Source		Coal
Net Summer Capability (megawatts)	25,252	14
Electric Utilities	20,802	10
Independent Power Producers & Combined Heat and Power	4,450	16
Net Generation (megawatthours)	125,608,139	10
Electric Utilities	112,029,989	6
Independent Power Producers & Combined Heat and Power	13,578,150	18
Emissions (thousand short tons)		
Sulfur Dioxide	786	3
Nitrogen Oxide	354	2
Carbon Dioxide	129,912	4
Sulfur Dioxide/sq. mile	22	3
Nitrogen Oxide/sq. mile	10	4
Carbon Dioxide/sq. mile	3,622	3
Utility and ESP Retail Electricity Sales (megawatthours)	101,428,550	11
Utility Retail Electricity Sales (megawatthours)	101,428,550	11
Direct Use (megawatthours)	4,594,016	10
Average Retail Price (cents/kWh)	5.34	48

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Indiana			
1. Gibson	Petroleum, Coal	PSI Energy Inc	3,131
2. Rockport	Petroleum, Coal	Indiana Michigan Power Co	2,600
3. R M Schahfer	Gas, Petroleum, Coal	Northern Indiana Pub Serv Co	1,780
4. AES Petersburg	Petroleum, Coal	Indianapolis Power & Light Co	1,702
5. Clifty Creek	Petroleum, Coal	Indiana-Kentucky Electric Corp	1,235
6. Cayuga	Petroleum, Gas, Coal	PSI Energy Inc	1,104
7. Harding Street	Petroleum, Gas, Coal	Indianapolis Power & Light Co	1,102
8. Merom	Petroleum, Coal	Hoosier Energy R E C Inc	1,000
9. Tanners Creek	Petroleum, Coal	Indiana Michigan Power Co	980
10. Wabash River	Petroleum, Gas, Coal	PSI Energy Inc	936

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Indiana					
A. PSI Energy, Inc.	27,272,584	8,483,853	7,131,102	11,587,870	69,759
B. Indiana Michigan Power Co.	15,916,602	4,581,098	4,144,351	7,118,111	73,042
C. Northern Indiana Pub Serv Co	15,792,412	3,228,343	3,618,327	8,822,406	123,336
D. Indianapolis Power & Light Co	14,446,437	4,938,673	2,018,031	7,417,297	72,436
E. Southern Indiana Gas & Elec Co	5,569,447	1,567,215	1,467,781	2,516,335	18,116
Total	78,997,482	22,799,182	18,379,592	37,462,019	356,689
Percentage of Utility Sales	78	72	84	79	61

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Indiana							
Coal	19,542	18,426	18,530	–0.6	90.2	87.6	73.4
Petroleum	480	486	473	–.2	2.2	2.3	1.9
Natural Gas	172	297	1,051	22.3	.8	1.4	4.2
Other Gases	0	143	0	NM	.0	.7	.0
Dual Fired	638	790	690	.9	2.9	3.8	2.7
Hydroelectric	69	59	59	–1.8	.3	.3	.2
Total Electric Utilities	**20,901**	**20,200**	**20,802**	**–.1**	**96.5**	**96.0**	**82.4**
Coal	206	185	1,410	23.8	1.0	.9	5.6
Petroleum	7	9	9	2.0	.0	.0	.0
Natural Gas	165	102	2,301	34.0	.8	.5	9.1
Other Gases	286	428	525	7.0	1.3	2.0	2.1
Dual Fired	96	96	185	7.5	.4	.5	.7
Other Renewables	6	17	21	14.7	.0	.1	.1
Total IPP's & Combined Heat and Power	**767**	**838**	**4,450**	**21.6**	**3.5**	**4.0**	**17.6**
Coal	19,748	18,611	19,940	.1	91.1	88.5	79.0
Petroleum	487	495	482	–.1	2.2	2.4	1.9
Natural Gas	337	399	3,352	29.1	1.6	1.9	13.3
Other Gases	286	571	525	7.0	1.3	2.7	2.1
Dual Fired	734	886	875	2.0	3.4	4.2	3.5
Hydroelectric	69	59	59	–1.8	.3	.3	.2
Other Renewables	6	17	21	14.7	.0	.1	.1
Total Electric Industry	**21,668**	**21,039**	**25,252**	**1.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Indiana							
Coal	98,776,088	108,911,799	109,441,044	1.1	95.3	94.9	87.1
Petroleum	197,848	606,905	470,976	10.1	.2	.5	.4
Natural Gas	528,813	385,994	1,706,699	13.9	.5	.3	1.4
Hydroelectric	448,400	561,593	411,270	–1.0	.4	.5	.3
Total Electric Utilities	**99,951,149**	**110,466,291**	**112,029,989**	**1.3**	**96.4**	**96.3**	**89.2**
Coal	900,865	1,139,863	8,218,656	27.8	.9	1.0	6.5
Petroleum	174,428	156,242	146,156	–1.9	.2	.1	.1
Natural Gas	445,785	847,108	2,075,753	18.6	.4	.7	1.7
Other Gases	2,130,459	1,995,347	3,005,998	3.9	2.1	1.7	2.4
Other Renewables	32,454	124,056	131,588	16.8	.0	.1	.1
Total IPP's & Combined Heat and Power	**3,683,990**	**4,262,616**	**13,578,150**	**15.6**	**3.6**	**3.7**	**10.8**
Coal	99,676,953	110,051,662	117,659,700	1.9	96.2	95.9	93.7
Petroleum	372,276	763,147	617,132	5.8	.4	.7	.5
Natural Gas	974,598	1,233,102	3,782,452	16.3	.9	1.1	3.0
Other Gases	2,130,459	1,995,347	3,005,998	3.9	2.1	1.7	2.4
Hydroelectric	448,400	561,593	411,270	–1.0	.4	.5	.3
Other Renewables	32,454	124,056	131,588	16.8	.0	.1	.1
Total Electric Industry	**103,635,139**	**114,728,907**	**125,608,139**	**2.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Indiana				
Coal (2002 cents per million Btu)	141.4	119.6	117.3	–2.0
Average heat value (Btu per pound)	10,539	10,461	10,326	–.2
Average sulfur Content(percent)	1.8	1.6	1.5	–2.0
Petroleum (2002 cents per million Btu)	406.5	154.0	208.1	–7.2
Average heat value (Btu per gallon)	126,977	81,176	139,717	1.1
Average sulfur Content(percent)	5.0	4.1	2.0	–9.7
Gas (2002 cents per million Btu)	305.1	325.0	323.5	.6
Average heat value (Btu per cubic foot)	1,013	1,021	1,023	.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Indiana				
Sulfur Dioxide				
Coal	1,266	998	785	–5.2
Petroleum	*	1	1	10.0
Gas	*	*	*	–.7
Other	*	*	*	–1.5
Total	1,266	999	786	–5.2
Nitrogen Oxide				
Coal	487	393	282	–5.9
Petroleum	*	*	*	–13.3
Gas	64	51	72	1.2
Other	*	*	1	25.8
Total	552	445	354	–4.8
Carbon Dioxide				
Coal	106,604	118,479	124,932	1.8
Petroleum	395	865	600	4.8
Gas	2,941	2,385	4,375	4.5
Other	7	7	6	–1.8
Total	109,946	121,736	129,912	1.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Indiana							
Retail Sales (thousand megawatthours)							
Residential	24,978	26,550	31,568	2.6	30.5	29.8	31.1
Commercial	17,015	18,514	21,790	2.8	20.8	20.8	21.5
Industrial	39,415	43,550	47,481	2.1	48.1	48.8	46.8
Other	523	533	589	1.3	.6	.6	.6
Total	81,931	89,147	101,429	2.4	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,856	1,895	2,183	1.8	39.3	39.1	40.3
Commercial	1,104	1,149	1,303	1.9	23.4	23.7	24.0
Industrial	1,705	1,748	1,877	1.1	36.1	36.1	34.6
Other	52	52	57	1.0	1.1	1.1	1.1
Total	4,718	4,843	5,420	1.5	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.43	7.14	6.91	–.8	NA	NA	NA
Commercial	6.49	6.20	5.98	–.9	NA	NA	NA
Industrial	4.32	4.01	3.95	–1.0	NA	NA	NA
Other	10.02	9.70	9.75	–.3	NA	NA	NA
Total	5.76	5.43	5.34	–.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Indiana						
Number of Entities	6	72	0	41	0	119
Number of Retail Customers	2,196,525	253,693	0	484,458	0	2,934,676
Retail Sales (thousand megawatthours)	83,449	7,696	0	10,283	0	101,429
Percentage of Retail Sales	82.27	7.59	.00	10.14	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	4,338	392	0	690	0	5,420
Percentage of Revenue	80.04	7.23	.00	12.74	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.20	5.09	.00	6.71	0	5.34

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Iowa		
NERC Region(s)		MAPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	9,338	33
Electric Utilities	8,407	27
Independent Power Producers & Combined Heat and Power	931	39
Net Generation (megawatthours)	42,528,385	33
Electric Utilities	40,051,665	27
Independent Power Producers & Combined Heat and Power	2,476,720	40
Emissions (thousand short tons)		
Sulfur Dioxide	148	22
Nitrogen Oxide	86	26
Carbon Dioxide	42,069	25
Sulfur Dioxide/sq. mile	3	26
Nitrogen Oxide/sq. mile	2	26
Carbon Dioxide/sq. mile	753	29
Utility and ESP Retail Electricity Sales (megawatthours)	40,897,543	31
Utility Retail Electricity Sales (megawatthours)	40,897,543	31
Direct Use (megawatthours)	1,350,932	23
Average Retail Price (cents/kWh)	6.01	33

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Iowa			
1. George Neal North	Gas, Coal	MidAmerican Energy Co	950
2. Council Bluffs	Gas, Petroleum, Coal	MidAmerican Energy Co	806
3. Ottumwa	Petroleum, Coal	Interstate Power and Light	720
4. Louisa	Petroleum, Gas, Coal	MidAmerican Energy Co	700
5. George Neal South	Petroleum, Coal	MidAmerican Energy Co	644
6. Duane Arnold	Nuclear	Interstate Power and Light	566
7. Lansing	Petroleum, Coal	Interstate Power and Light	319
8. Burlington	Gas, Coal	Interstate Power and Light	285
9. Archer Daniels Midlan	Coal	Archer Daniels Midland Co	260
10. Milton L Kapp	Gas, Coal	Interstate Power and Light	236

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Iowa					
A. MidAmerican Energy Company	16,389,557	4,759,645	3,445,081	5,995,047	2,189,784
B. Interstate Power & Light Co	14,375,098	3,787,754	3,199,333	7,316,726	71,285
C. Eastern Iowa Light&Power Coop	1,203,905	261,867	32,278	906,201	3,559
D. Muscatine Power and Water	826,189	99,460	147,408	554,931	24,390
E. City of Ames	577,353	145,094	204,330	127,960	99,969
Total	33,372,102	9,053,820	7,028,430	14,900,865	2,388,987
Percentage of Utility Sales	82	70	80	90	91

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Iowa							
Coal	5,818	5,573	5,620	–0.4	68.6	64.9	60.2
Petroleum	508	660	846	5.8	6.0	7.7	9.1
Natural Gas	162	152	104	–4.8	1.9	1.8	1.1
Dual Fired	946	974	1,036	1.0	11.1	11.3	11.1
Nuclear	515	535	566	1.0	6.1	6.2	6.1
Hydroelectric	125	136	129	.4	1.5	1.6	1.4
Other Renewables	*	*	107	122.4	.0	.0	1.1
Other	0	209	0	NM	.0	2.4	.0
Total Electric Utilities	**8,074**	**8,238**	**8,407**	**.5**	**95.1**	**95.9**	**90.0**
Coal	259	268	419	5.5	3.1	3.1	4.5
Petroleum	80	69	82	.4	.9	.8	.9
Natural Gas	*	*	4	27.7	.0	.0	.0
Dual Fired	64	3	0	NM	.8	.0	.0
Hydroelectric	5	5	2	–9.5	.1	.1	.0
Other Renewables	5	8	422	64.1	.1	.1	4.5
Total IPP's & Combined Heat and Power	**413**	**353**	**931**	**9.4**	**4.9**	**4.1**	**10.0**
Coal	6,077	5,840	6,039	–.1	71.6	68.0	64.7
Petroleum	587	729	929	5.2	6.9	8.5	9.9
Natural Gas	163	152	108	–4.4	1.9	1.8	1.2
Dual Fired	1,010	977	1,036	.3	11.9	11.4	11.1
Nuclear	515	535	566	1.0	6.1	6.2	6.1
Hydroelectric	130	141	131	.1	1.5	1.6	1.4
Other Renewables	5	8	529	68.0	.1	.1	5.7
Other	0	209	0	NM	.0	2.4	.0
Total Electric Industry	**8,487**	**8,591**	**9,338**	**1.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Iowa							
Coal	26,642,524	28,739,404	34,033,119	2.8	83.1	81.1	80.0
Petroleum	49,511	81,984	55,552	1.3	.2	.2	.1
Natural Gas	308,065	276,627	406,796	3.1	1.0	.8	1.0
Nuclear	3,235,009	4,149,111	4,573,958	3.9	10.1	11.7	10.8
Hydroelectric	737,023	794,739	936,689	2.7	2.3	2.2	2.2
Other Renewables	19,558	22,478	45,552	9.8	.1	.1	.1
Total Electric Utilities	**30,991,690**	**34,064,343**	**40,051,665**	**2.9**	**96.7**	**96.2**	**94.2**
Coal	889,120	1,093,821	1,338,939	4.7	2.8	3.1	3.1
Petroleum	7,415	8,208	8,312	1.3	.0	.0	.0
Natural Gas	140,924	161,064	147,924	.5	.4	.5	.3
Hydroelectric	10,159	10,205	9,695	–.5	.0	.0	.0
Other Renewables	9,705	81,298	971,850	66.8	.0	.2	2.3
Total IPP's & Combined Heat and Power	**1,057,323**	**1,354,596**	**2,476,720**	**9.9**	**3.3**	**3.8**	**5.8**
Coal	27,531,644	29,833,225	35,372,058	2.8	85.9	84.2	83.2
Petroleum	56,926	90,192	63,864	1.3	.2	.3	.2
Natural Gas	448,989	437,691	554,719	2.4	1.4	1.2	1.3
Nuclear	3,235,009	4,149,111	4,573,958	3.9	10.1	11.7	10.8
Hydroelectric	747,182	804,944	946,384	2.7	2.3	2.3	2.2
Other Renewables	29,263	103,776	1,017,402	48.3	.1	.3	2.4
Total Electric Industry	**32,049,013**	**35,418,939**	**42,528,385**	**3.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Iowa				
Coal (2002 cents per million Btu)	112.8	96.3	88.8	–2.6
Average heat value (Btu per pound)	8,660	8,662	8,860	.3
Average sulfur Content(percent)	.5	.4	.4	–3.1
Petroleum (2002 cents per million Btu)	141.3	144.9	579.0	17.0
Average heat value (Btu per gallon)	83,080	83,517	137,281	5.7
Average sulfur Content(percent)	5.1	5.6	*	–49.9
Gas (2002 cents per million Btu)	345.8	349.2	386.6	1.2
Average heat value (Btu per cubic foot)	1,006	1,003	1,015	.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Iowa				
Sulfur Dioxide				
Coal	184	159	148	-2.4
Petroleum	6	9	*	-42.0
Gas	0	0	0	NM
Other	*	1	0	NM
Total	190	169	148	-2.7
Nitrogen Oxide				
Coal	144	79	85	-5.7
Petroleum	1	1	*	-33.5
Gas	1	1	1	.2
Other	*	1	*	3.0
Total	146	82	86	-5.7
Carbon Dioxide				
Coal	31,721	34,784	41,458	3.0
Petroleum	63	107	69	1.1
Gas	397	444	542	3.5
Other	*	0	0	NM
Total	32,181	35,335	42,069	3.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Iowa							
Retail Sales (thousand megawatthours)							
Residential	11,103	11,673	12,921	1.7	34.6	32.3	31.6
Commercial	7,269	7,594	8,803	2.1	22.6	21.0	21.5
Industrial	12,465	15,531	16,548	3.2	38.8	43.0	40.5
Other	1,267	1,350	2,626	8.4	3.9	3.7	6.4
Total	32,104	36,148	40,898	2.7	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	992	985	1,079	.9	46.5	44.4	43.9
Commercial	515	516	578	1.3	24.1	23.3	23.5
Industrial	545	631	672	2.4	25.5	28.5	27.3
Other	83	84	129	5.1	3.9	3.8	5.3
Total	2,134	2,216	2,458	1.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.93	8.43	8.35	-.7	NA	NA	NA
Commercial	7.09	6.80	6.56	-.8	NA	NA	NA
Industrial	4.37	4.06	4.06	-.8	NA	NA	NA
Other	6.52	6.26	4.92	-3.1	NA	NA	NA
Total	6.65	6.13	6.01	-1.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Iowa						
Number of Entities	3	138	0	43	0	184
Number of Retail Customers	1,058,715	200,267	0	200,997	0	1,459,979
Retail Sales (thousand megawatthours)	30,852	4,978	0	5,067	0	40,898
Percentage of Retail Sales	75.44	12.17	.00	12.39	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,828	282	0	348	0	2,458
Percentage of Revenue	74.35	11.47	.00	14.18	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.92	5.67	.00	6.88	0	6.01

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Kansas		
NERC Region(s)		SPP/MAPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	10,396	31
Electric Utilities	10,244	23
Independent Power Producers & Combined Heat and Power	152	48
Net Generation (megawatthours)	47,188,446	28
Electric Utilities	46,691,936	22
Independent Power Producers & Combined Heat and Power	496,510	47
Emissions (thousand short tons)		
Sulfur Dioxide	130	24
Nitrogen Oxide	95	21
Carbon Dioxide	43,523	24
Sulfur Dioxide/sq. mile	2	31
Nitrogen Oxide/sq. mile	1	31
Carbon Dioxide/sq. mile	532	33
Utility and ESP Retail Electricity Sales (megawatthours)	36,713,540	32
Utility Retail Electricity Sales (megawatthours)	36,713,540	32
Direct Use (megawatthours)	7,994	42
Average Retail Price (cents/kWh)	6.31	25

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Kansas			
1. Jeffrey Energy Center	Petroleum, Coal	Western Resources Inc	2,212
2. La Cygne	Petroleum, Coal	Kansas City Power & Light Co	1,362
3. Wolf Creek Generating	Nuclear	Wolf Creek Nuclear Optg Corp	1,170
4. Gordon Evans Energy C	Petroleum, Gas	Kansas Gas & Electric Co	833
5. Lawrence Energy Cente	Gas, Coal	Western Resources Inc	598
6. Hutchinson Energy Cen	Petroleum, Gas	Western Resources Inc	478
7. Holcomb	Gas, Coal	Sunflower Electric Power Corp	360
8. Murray Gill	Petroleum, Gas	Kansas Gas & Electric Co	323
9. Quindaro	Petroleum, Gas, Coal	Kansas City City of	316
10. Tecumseh Energy Cente	Gas, Coal	Western Resources Inc	284

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Kansas					
A. Western Resources, Inc	9,539,068	3,281,055	4,141,584	2,053,967	62,462
B. Kansas Gas & Electric Company	9,005,365	2,889,469	2,675,312	3,396,771	43,813
C. Kansas City Power & Light Co	5,771,059	2,550,772	2,826,563	374,782	18,942
D. Board of Public Utilities	2,271,425	568,601	806,032	822,335	74,457
E. UtiliCorp United, Inc	1,831,780	489,924	558,259	760,050	23,547
Total	28,418,697	9,779,821	11,007,750	7,407,905	223,221
Percentage of Utility Sales	77	77	82	73	59

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Kansas							
Coal	5,189	5,364	5,310	0.3	53.2	54.5	51.1
Petroleum	214	216	265	2.4	2.2	2.2	2.5
Natural Gas	532	378	590	1.1	5.5	3.8	5.7
Dual Fired	2,637	2,666	2,910	1.1	27.0	27.1	28.0
Nuclear	1,134	1,163	1,170	.3	11.6	11.8	11.3
Other Renewables	*	0	0	NM	.0	.0	.0
Total Electric Utilities	**9,706**	**9,786**	**10,244**	**.6**	**99.5**	**99.5**	**98.5**
Petroleum	4	4	4	.2	.0	.0	.0
Natural Gas	1	6	29	42.3	.0	.1	.3
Dual Fired	37	37	4	-22.5	.4	.4	.0
Hydroelectric	2	2	2	.6	.0	.0	.0
Other Renewables	0	0	112	NM	.0	.0	1.1
Total IPP's & Combined Heat and Power	**44**	**49**	**152**	**14.6**	**.5**	**.5**	**1.5**
Coal	5,189	5,364	5,310	.3	53.2	54.5	51.1
Petroleum	218	220	269	2.4	2.2	2.2	2.6
Natural Gas	533	383	619	1.7	5.5	3.9	6.0
Dual Fired	2,674	2,703	2,914	1.0	27.4	27.5	28.0
Nuclear	1,134	1,163	1,170	.3	11.6	11.8	11.3
Hydroelectric	2	2	2	.6	.0	.0	.0
Other Renewables	*	0	112	135.6	.0	.0	1.1
Total Electric Industry	**9,750**	**9,836**	**10,396**	**.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Kansas							
Coal	26,799,665	27,235,875	35,369,189	3.1	72.9	71.8	75.0
Petroleum	76,463	109,885	508,857	23.4	.2	.3	1.1
Natural Gas	1,656,848	2,067,501	1,772,188	.8	4.5	5.5	3.8
Nuclear	7,899,543	8,430,455	9,041,702	1.5	21.5	22.2	19.2
Other Renewables	58	0	0	NM	.0	.0	.0
Total Electric Utilities	**36,432,577**	**37,843,716**	**46,691,936**	**2.8**	**99.2**	**99.8**	**98.9**
Petroleum	19,400	878	222	-39.2	.1	.0	.0
Natural Gas	285,606	59,010	16,864	-27.0	.8	.2	.0
Hydroelectric	4,985	13,881	12,746	11.0	.0	.0	.0
Other Renewables	0	0	466,679	NM	.0	.0	1.0
Total IPP's & Combined Heat and Power	**309,990**	**73,769**	**496,510**	**5.4**	**.8**	**.2**	**1.1**
Coal	26,799,665	27,235,875	35,369,189	3.1	72.9	71.8	75.0
Petroleum	95,863	110,763	509,078	20.4	.3	.3	1.1
Natural Gas	1,942,454	2,126,511	1,789,052	-.9	5.3	5.6	3.8
Nuclear	7,899,543	8,430,455	9,041,702	1.5	21.5	22.2	19.2
Hydroelectric	4,985	13,881	12,746	11.0	.0	.0	.0
Other Renewables	58	0	466,679	171.6	.0	.0	1.0
Total Electric Industry	**36,742,567**	**37,917,485**	**47,188,446**	**2.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Kansas				
Coal (2002 cents per million Btu)	113.9	105.0	98.3	–1.6
Average heat value (Btu per pound)	8,654	8,766	8,548	–.1
Average sulfur Content(percent)	.4	.5	.4	.3
Petroleum (2002 cents per million Btu)	448.6	289.9	272.7	–5.4
Average heat value (Btu per gallon)	138,636	154,118	152,240	1.0
Average sulfur Content(percent)	1.7	1.1	1.6	–.8
Gas (2002 cents per million Btu)	258.7	265.5	309.4	2.0
Average heat value (Btu per cubic foot)	975	978	1,000	.3

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Kansas				
Sulfur Dioxide				
Coal	70	108	124	6.6
Petroleum	*	1	5	31.5
Gas	0	0	0	NM
Total	71	109	130	7.0
Nitrogen Oxide				
Coal	116	78	91	–2.7
Petroleum	*	*	1	28.5
Gas	3	4	3	–.3
Total	120	83	95	–2.5
Carbon Dioxide				
Coal	31,540	32,472	41,781	3.2
Petroleum	105	127	504	19.1
Gas	1,363	1,526	1,238	–1.1
Total	33,007	34,126	43,523	3.1

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Kansas							
Retail Sales (thousand megawatthours)							
Residential	9,986	10,862	12,745	2.8	34.7	33.7	34.7
Commercial	9,753	11,424	13,392	3.6	33.9	35.4	36.5
Industrial	8,702	9,365	10,195	1.8	30.2	29.0	27.8
Other	367	618	381	.4	1.3	1.9	1.0
Total	28,808	32,270	36,714	2.7	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	875	860	977	1.2	41.3	41.1	42.2
Commercial	728	759	841	1.6	34.4	36.3	36.3
Industrial	479	434	462	–.4	22.6	20.8	19.9
Other	36	38	35	–.3	1.7	1.8	1.5
Total	2,119	2,092	2,315	1.0	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.76	7.92	7.67	–1.5	NA	NA	NA
Commercial	7.47	6.64	6.28	–1.9	NA	NA	NA
Industrial	5.51	4.64	4.53	–2.1	NA	NA	NA
Other	9.93	6.14	9.30	–.7	NA	NA	NA
Total	7.35	6.48	6.31	–1.7	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Kansas						
Number of Entities	4	124	0	26	0	154
Number of Retail Customers	865,469	340,274	0	173,604	0	1,379,347
Retail Sales (thousand megawatthours)	24,338	9,133	0	3,242	0	36,714
Percentage of Retail Sales	66.29	24.88	.00	8.83	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,464	578	0	274	0	2,315
Percentage of Revenue	63.24	24.94	.00	11.82	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.02	6.32	.00	8.44	0	6.31

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Kentucky		
NERC Region(s)		ECAR/SERC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	19,122	20
Electric Utilities	15,418	16
Independent Power Producers & Combined Heat and Power	3,704	20
Net Generation (megawatthours)	92,106,668	19
Electric Utilities	80,161,524	13
Independent Power Producers & Combined Heat and Power	11,945,144	21
Emissions (thousand short tons)		
Sulfur Dioxide	485	8
Nitrogen Oxide	199	7
Carbon Dioxide	95,879	7
Sulfur Dioxide/sq. mile	12	9
Nitrogen Oxide/sq. mile	5	9
Carbon Dioxide/sq. mile	2,413	12
Utility and ESP Retail Electricity Sales (megawatthours)	87,266,835	14
Utility Retail Electricity Sales (megawatthours)	87,266,835	14
Direct Use (megawatthours)	438,767	31
Average Retail Price (cents/kWh)	4.26	51

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Kentucky			
1. Paradise	Petroleum, Coal	Tennessee Valley Authority	2,159
2. Ghent	Petroleum, Coal	Kentucky Utilities Co	1,966
3. E W Brown	Petroleum, Gas, Coal	Kentucky Utilities Co	1,663
4. Mill Creek	Petroleum, Gas, Coal	Louisville Gas & Electric Co	1,485
5. Shawnee	Petroleum, Coal	Tennessee Valley Authority	1,330
6. Big Sandy	Petroleum, Coal	Kentucky Power Co	1,060
7. H L Spurlock	Petroleum, Coal	East Kentucky Power Coop Inc	850
8. Trimble County	Petroleum, Gas, Coal	Louisville Gas & Electric Co	822
9. East Bend	Petroleum, Coal	Cincinnati Gas & Electric Co	600
10. Cane Run	Petroleum, Gas, Coal	Louisville Gas & Electric Co	577

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Kentucky					
A. Kentucky Utilities Company	16,731,361	5,784,469	3,974,238	5,504,635	1,468,019
B. Tennessee Valley Authority	12,497,936	0	0	12,468,308	29,628
C. Louisville Gas & Electric Co	11,810,125	4,035,725	3,492,517	3,028,490	1,253,393
D. Kenergy Corporation	9,299,459	704,769	231,655	8,319,315	43,720
E. Kentucky Power Company	6,961,064	2,468,625	1,327,062	3,154,026	11,351
Total	57,299,945	12,993,588	9,025,472	32,474,774	2,806,111
Percentage of Utility Sales	66	51	61	74	83

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Kentucky							
Coal	14,093	14,135	12,496	–1.3	92.1	90.2	65.3
Petroleum	134	134	70	–7.0	.9	.9	.4
Natural Gas	207	92	673	14.0	1.4	.6	3.5
Dual Fired	68	508	1,358	39.5	.4	3.2	7.1
Hydroelectric	795	791	821	.4	5.2	5.0	4.3
Total Electric Utilities	**15,297**	**15,660**	**15,419**	**.1**	**100.0**	**100.0**	**80.6**
Coal	0	0	1,716	NM	.0	.0	9.0
Natural Gas	0	0	1,328	NM	.0	.0	6.9
Dual Fired	0	0	609	NM	.0	.0	3.2
Other Renewables	0	4	51	NM	.0	.0	.3
Total IPP's & Combined Heat and Power	**0**	**4**	**3,704**	**NM**	**.0**	**.0**	**19.4**
Coal	14,093	14,135	14,212	.1	92.1	90.2	74.3
Petroleum	134	134	70	–7.0	.9	.9	.4
Natural Gas	207	92	2,001	28.7	1.4	.6	10.5
Dual Fired	68	508	1,967	45.3	.4	3.2	10.3
Hydroelectric	795	791	821	.4	5.2	5.0	4.3
Other Renewables	0	4	51	NM	.0	.0	.3
Total Electric Industry	**15,297**	**15,663**	**19,123**	**2.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Kentucky							
Coal	81,722,246	87,875,331	75,308,162	–0.9	96.1	96.0	81.8
Petroleum	96,727	125,625	135,412	3.8	.1	.1	.1
Natural Gas	23,632	176,857	693,201	45.6	.0	.2	.8
Hydroelectric	3,155,113	3,380,233	4,024,749	2.7	3.7	3.7	4.4
Total Electric Utilities	**84,997,718**	**91,558,046**	**80,161,524**	**–.6**	**100.0**	**100.0**	**87.0**
Coal	0	0	7,966,084	NM	.0	.0	8.6
Petroleum	0	0	2,933,086	NM	.0	.0	3.2
Natural Gas	0	0	680,509	NM	.0	.0	.7
Other Renewables	0	14,049	365,465	NM	.0	.0	.4
Total IPP's & Combined Heat and Power	**0**	**14,049**	**11,945,144**	**NM**	**.0**	**.0**	**13.0**
Coal	81,722,246	87,875,331	83,274,246	.2	96.1	96.0	90.4
Petroleum	96,727	125,625	3,068,498	46.8	.1	.1	3.3
Natural Gas	23,632	176,857	1,373,710	57.1	.0	.2	1.5
Hydroelectric	3,155,113	3,380,233	4,024,749	2.7	3.7	3.7	4.4
Other Renewables	0	14,049	365,465	NM	.0	.0	.4
Total Electric Industry	**84,997,718**	**91,572,095**	**92,106,668**	**.9**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Kentucky				
Coal (2002 cents per million Btu)	130.0	107.5	118.8	-1.0
Average heat value (Btu per pound)	11,697	11,571	11,513	-.2
Average sulfur Content(percent)	2.4	2.5	2.2	-1.1
Petroleum (2002 cents per million Btu)	227.5	371.2	464.6	8.3
Average heat value (Btu per gallon)	90,576	116,977	133,017	4.4
Average sulfur Content(percent)	5.4	4.8	1.0	-16.7
Gas (2002 cents per million Btu)	335.7	346.7	351.2	.5
Average heat value (Btu per cubic foot)	1,020	1,023	1,023	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Kentucky				
Sulfur Dioxide				
Coal	979	671	471	-7.8
Petroleum	*	*	12	59.2
Gas	0	0	*	NM
Other	0	0	2	NM
Total	979	671	485	-7.5
Nitrogen Oxide				
Coal	356	365	192	-6.6
Petroleum	*	*	6	58.9
Gas	*	*	1	48.9
Other	0	*	1	NM
Total	356	365	199	-6.2
Carbon Dioxide				
Coal	83,468	90,024	90,567	.9
Petroleum	100	124	4,439	52.4
Gas	16	130	874	56.0
Total	83,584	90,279	95,879	1.5

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Kentucky							
Retail Sales (thousand megawatthours)							
Residential	19,223	20,998	25,347	3.1	28.2	27.3	29.0
Commercial	9,829	12,169	14,745	4.6	14.4	15.8	16.9
Industrial	36,320	40,600	43,812	2.1	53.3	52.8	50.2
Other	2,777	3,069	3,362	2.1	4.1	4.0	3.8
Total	68,149	76,836	87,267	2.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,221	1,205	1,431	1.8	37.2	37.8	38.5
Commercial	579	662	782	3.4	17.6	20.8	21.0
Industrial	1,334	1,170	1,353	.1	40.7	36.8	36.3
Other	145	146	155	.8	4.4	4.6	4.2
Total	3,279	3,183	3,721	1.4	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	6.35	5.74	5.65	−1.3	NA	NA	NA
Commercial	5.89	5.44	5.30	−1.1	NA	NA	NA
Industrial	3.67	2.88	3.09	−1.9	NA	NA	NA
Other	5.21	4.77	4.61	−1.4	NA	NA	NA
Total	4.81	4.14	4.26	−1.3	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Kentucky						
Number of Entities	6	31	0	24	0	61
Number of Retail Customers	1,160,234	201,168	0	730,491	0	2,091,893
Retail Sales (thousand megawatthours)	43,208	19,153	0	24,906	0	87,267
Percentage of Retail Sales	49.51	21.95	.00	28.54	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,852	672	0	1,197	0	3,721
Percentage of Revenue	49.78	18.06	.00	32.16	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	4.29	3.51	.00	4.80	0	4.26

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Louisiana		
NERC Region(s)		SPP/SERC
Primary Energy Source		Gas
Net Summer Capability (megawatts)	25,633	13
Electric Utilities	14,233	17
Independent Power Producers & Combined Heat and Power	11,399	8
Net Generation (megawatthours)	94,970,963	16
Electric Utilities	54,921,960	18
Independent Power Producers & Combined Heat and Power	40,049,003	9
Emissions (thousand short tons)		
Sulfur Dioxide	181	20
Nitrogen Oxide	116	15
Carbon Dioxide	56,112	16
Sulfur Dioxide/sq. mile	4	23
Nitrogen Oxide/sq. mile	3	19
Carbon Dioxide/sq. mile	1,288	22
Utility and ESP Retail Electricity Sales (megawatthours)	79,260,989	16
Utility Retail Electricity Sales (megawatthours)	79,260,989	16
Direct Use (megawatthours)	22,346,903	3
Average Retail Price (cents/kWh)	5.99	35

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Louisiana			
1. Willow Glen	Petroleum, Gas	Entergy Gulf States Inc	1,787
2. Big Cajun 2	Petroleum, Coal	Louisiana Generating LLC	1,730
3. Nine Mile Point	Petroleum, Gas	Entergy Louisiana Inc	1,705
4. Little Gypsy	Gas	Entergy Louisiana Inc	1,204
5. R S Nelson	Petroleum, Gas, Coal	Entergy Gulf States Inc	1,203
6. Waterford 3	Nuclear	Entergy Louisiana Inc	1,091
7. Acadia Energy Center	Gas	Calpine Corp	1,082
8. River Bend	Nuclear	Entergy Gulf States Inc	980
9. Rodemacher	Petroleum, Gas, Coal	CLECO Power LLC	963
10. Michoud	Petroleum, Gas	Entergy New Orleans Inc	825

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Louisiana					
A. Entergy Louisiana, Inc	29,566,325	8,780,158	5,538,479	14,737,545	510,143
B. Entergy Gulf States, Inc	18,772,582	4,519,927	4,316,062	9,714,398	222,195
C. Cleco Power, LLC	8,470,579	3,400,026	1,721,711	2,756,212	592,630
D. Entergy New Orleans, Inc	5,877,846	2,158,084	2,255,283	409,152	1,055,327
E. Southwestern Electric Power Co	5,156,957	2,154,103	1,725,381	1,077,504	199,969
Total	67,844,289	21,012,298	15,556,916	28,694,811	2,580,264
Percentage of Utility Sales	86	75	83	97	94

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Louisiana							
Coal	3,343	3,453	1,723	-7.1	17.0	16.9	6.7
Petroleum	16	16	16	.0	.1	.1	.1
Natural Gas	1,811	1,910	1,735	-.5	9.2	9.4	6.8
Dual Fired	9,709	9,689	8,689	-1.2	49.5	47.5	33.9
Nuclear	2,006	2,011	2,071	.4	10.2	9.9	8.1
Total Electric Utilities	**16,885**	**17,079**	**14,233**	**-1.9**	**86.0**	**83.7**	**55.5**
Coal	8	8	1,730	81.8	.0	.0	6.7
Petroleum	0	6	46	NM	.0	.0	.2
Natural Gas	1,652	2,285	8,724	20.3	8.4	11.2	34.0
Other Gases	10	27	62	22.7	.1	.1	.2
Dual Fired	378	290	451	2.0	1.9	1.4	1.8
Hydroelectric	182	182	192	.6	.9	.9	.7
Other Renewables	487	517	170	-11.0	2.5	2.5	.7
Other	21	21	24	1.6	.1	.1	.1
Total IPP's & Combined Heat and Power	**2,739**	**3,337**	**11,399**	**17.2**	**14.0**	**16.3**	**44.5**
Coal	3,351	3,461	3,453	.3	17.1	17.0	13.5
Petroleum	16	22	62	16.2	.1	.1	.2
Natural Gas	3,463	4,195	10,458	13.1	17.6	20.5	40.8
Other Gases	10	27	62	22.7	.1	.1	.2
Dual Fired	10,087	9,980	9,140	-1.1	51.4	48.9	35.7
Nuclear	2,006	2,011	2,071	.4	10.2	9.9	8.1
Hydroelectric	182	182	192	.6	.9	.9	.7
Other Renewables	487	517	170	-11.0	2.5	2.5	.7
Other	21	21	24	1.6	.1	.1	.1
Total Electric Industry	**19,624**	**20,416**	**25,633**	**3.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Louisiana							
Coal	19,365,873	20,952,995	12,258,694	-5.0	24.5	25.3	12.9
Petroleum	1,837,844	645,547	68,460	-30.6	2.3	.8	.1
Natural Gas	23,750,752	26,010,452	25,085,994	.6	30.1	31.4	26.4
Other Gases	0	0	203,484	NM	.0	.0	.2
Nuclear	14,398,103	13,511,008	17,305,328	2.1	18.2	16.3	18.2
Total Electric Utilities	**59,352,572**	**61,120,002**	**54,921,960**	**-.9**	**75.2**	**73.8**	**57.8**
Coal	45,855	54,126	9,792,212	81.5	.1	.1	10.3
Petroleum	1,649,723	1,640,597	1,796,076	.9	2.1	2.0	1.9
Natural Gas	12,604,472	14,566,110	22,814,854	6.8	16.0	17.6	24.0
Other Gases	700,587	1,088,279	1,294,140	7.1	.9	1.3	1.4
Hydroelectric	1,231,946	1,035,961	891,441	-3.5	1.6	1.3	.9
Other Renewables	2,674,066	3,138,770	2,862,791	.8	3.4	3.8	3.0
Other	716,315	177,799	597,490	-2.0	.9	.2	.6
Total IPP's & Combined Heat and Power	**19,622,964**	**21,701,640**	**40,049,003**	**8.2**	**24.8**	**26.2**	**42.2**
Coal	19,411,728	21,007,121	22,050,906	1.4	24.6	25.4	23.2
Petroleum	3,487,567	2,286,144	1,864,536	-6.7	4.4	2.8	2.0
Natural Gas	36,355,224	40,576,562	47,900,848	3.1	46.0	49.0	50.4
Other Gases	700,587	1,088,279	1,497,624	8.8	.9	1.3	1.6
Nuclear	14,398,103	13,511,008	17,305,328	2.1	18.2	16.3	18.2
Hydroelectric	1,231,946	1,035,961	891,441	-3.5	1.6	1.3	.9
Other Renewables	2,674,066	3,138,770	2,862,791	.8	3.4	3.8	3.0
Other	716,315	177,799	597,490	-2.0	.9	.2	.6
Total Electric Industry	**78,975,536**	**82,821,642**	**94,970,963**	**2.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Louisiana				
Coal (2002 cents per million Btu)	176.7	152.0	126.8	-3.6
Average heat value (Btu per pound)	8,092	8,102	7,904	-.3
Average sulfur Content(percent)	.5	.6	.5	*
Petroleum (2002 cents per million Btu)	248.3	310.2	63.4	-14.1
Average heat value (Btu per gallon)	152,148	153,519	140,060	-.9
Average sulfur Content(percent)	1.1	1.3	5.4	19.8
Gas (2002 cents per million Btu)	265.9	276.8	342.4	2.8
Average heat value (Btu per cubic foot)	1,043	1,036	1,029	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Louisiana				
Sulfur Dioxide				
Coal	116	104	87	-3.2
Petroleum	120	82	88	-3.4
Gas	*	*	*	8.2
Other	6	7	6	-.6
Total	243	192	180	-3.2
Nitrogen Oxide				
Coal	94	43	44	-8.0
Petroleum	8	7	5	-4.8
Gas	40	57	64	5.4
Other	2	2	2	-.9
Total	145	109	116	-2.5
Carbon Dioxide				
Coal	22,565	23,789	24,609	1.0
Petroleum	3,976	2,662	2,148	-6.6
Gas	21,183	25,284	29,355	3.7
Other	*	0	0	NM
Total	47,725	51,735	56,112	1.8

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Louisiana							
Retail Sales (thousand megawatthours)							
Residential	22,430	24,502	28,157	2.6	33.1	32.3	35.5
Commercial	14,398	16,222	18,686	2.9	21.3	21.4	23.6
Industrial	28,439	32,493	29,662	.5	42.0	42.8	37.4
Other	2,488	2,669	2,756	1.1	3.7	3.5	3.5
Total	67,756	75,886	79,261	1.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,939	1,861	2,000	.3	41.0	39.9	42.1
Commercial	1,183	1,165	1,242	.5	25.0	24.9	26.2
Industrial	1,406	1,466	1,310	-.8	29.8	31.4	27.6
Other	197	178	194	-.2	4.2	3.8	4.1
Total	4,725	4,670	4,746	*	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.64	7.60	7.10	-2.2	NA	NA	NA
Commercial	8.22	7.18	6.64	-2.3	NA	NA	NA
Industrial	4.94	4.51	4.42	-1.2	NA	NA	NA
Other	7.93	6.66	7.05	-1.3	NA	NA	NA
Total	6.97	6.15	5.99	-1.7	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Louisiana						
Number of Entities	4	24	0	12	0	40
Number of Retail Customers	1,431,652	319,837	0	359,279	0	2,110,768
Retail Sales (thousand megawatthours)	62,687	9,341	0	7,232	0	79,261
Percentage of Retail Sales	79.09	11.79	.00	9.12	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	3,728	542	0	477	0	4,746
Percentage of Revenue	78.53	11.42	.00	10.05	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.95	5.80	.00	6.59	0	5.99

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Maine		
NERC Region(s)		NPCC
Primary Energy Source		Gas
Net Summer Capability (megawatts)	4,288	42
Electric Utilities	16	49
Independent Power Producers & Combined Heat and Power	4,272	18
Net Generation (megawatthours)	22,535,033	42
Electric Utilities	865	50
Independent Power Producers & Combined Heat and Power	22,534,168	12
Emissions (thousand short tons)		
Sulfur Dioxide	14	43
Nitrogen Oxide	9	46
Carbon Dioxide	7,360	43
Sulfur Dioxide/sq. mile	0	41
Nitrogen Oxide/sq. mile	0	45
Carbon Dioxide/sq. mile	238	43
Utility and ESP Retail Electricity Sales (megawatthours)	9,635,779	47
Utility Retail Electricity Sales (megawatthours)	1,025,206	51
ESP Retail Electricity Sales (megawatthours)	8,610,573	6
Direct Use (megawatthours)	4,601,858	9
Average Retail Price (cents/kWh)	11.36	3

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Maine			
1. William F Wyman	Petroleum	FPL Energy Wyman LLC	825
2. Westbrook Energy Cent	Gas	Calpine Eastern Corp	506
3. Maine Independence St	Gas	Casco Bay Energy Co LLC	494
4. Rumford Power Associa	Gas	Calpine Corp	254
5. Champion Clean Energy	Petroleum, Gas	IPC Bucksport	176
6. Androscoggin Energy C	Petroleum, Gas	Calpine Androscoggin Energy	130
7. Great Northern Paper	Hydro	Great Lakes Hydro America LLC	125
8. Somerset Plant	Petroleum, Other	S D Warren Co	115
9. Millinocket Mill	Other, Petroleum	Great Lakes Hydro America LLC	103
10. Mason Steam	Petroleum	FPL Energy Mason LLC	98

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Maine					
A. Constellation Power Source Inc	4,287,170	3,316,654	924,849	45,667	0
B. New Energy Ventures, Inc	1,357,465	0	1,357,465	0	0
C. WPS Energy Services, Inc	1,122,620	389,267	339,334	387,845	6,174
D. Energy Atlantic LLC	811,755	555,697	209,588	46,470	0
E. Enron Energy Services, Inc	567,053	0	567,053	0	0
Total	8,146,063	4,261,618	3,398,289	479,982	6,174
Percentage of Utility Sales	85	95	86	41	15

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Maine							
Petroleum	1,111	1,064	16	-37.4	29.4	37.2	0.4
Nuclear	870	0	0	NM	23.0	.0	.0
Hydroelectric	421	404	0	NM	11.1	14.1	.0
Other Renewables	0	30	0	NM	.0	1.0	.0
Total Electric Utilities	**2,402**	**1,498**	**16**	**-42.6**	**63.5**	**52.4**	**.4**
Coal	100	96	85	-1.8	2.6	3.3	2.0
Petroleum	181	227	1,097	22.1	4.8	8.0	25.6
Natural Gas	0	0	1,356	NM	.0	.0	31.6
Dual Fired	12	15	318	43.9	.3	.5	7.4
Hydroelectric	352	354	718	8.3	9.3	12.4	16.7
Other Renewables	737	669	698	-.6	19.5	23.4	16.3
Total IPP's & Combined Heat and Power	**1,382**	**1,361**	**4,272**	**13.4**	**36.5**	**47.6**	**99.6**
Coal	100	96	85	-1.8	2.6	3.3	2.0
Petroleum	1,292	1,292	1,113	-1.6	34.2	45.2	26.0
Natural Gas	0	0	1,356	NM	.0	.0	31.6
Dual Fired	12	15	318	43.9	.3	.5	7.4
Nuclear	870	0	0	NM	23.0	.0	.0
Hydroelectric	772	758	718	-.8	20.4	26.5	16.7
Other Renewables	737	699	698	-.6	19.5	24.4	16.3
Total Electric Industry	**3,784**	**2,859**	**4,288**	**1.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Maine							
Petroleum	760,460	1,442,898	865	-52.9	4.9	14.0	0.0
Nuclear	5,739,866	0	0	NM	36.8	.0	.0
Hydroelectric	1,575,593	1,779,887	0	NM	10.1	17.2	.0
Total Electric Utilities	**8,075,919**	**3,222,785**	**865**	**-63.8**	**51.7**	**31.2**	**.0**
Coal	549,170	612,223	603,938	1.1	3.5	5.9	2.7
Petroleum	1,102,631	1,042,309	1,228,620	1.2	7.1	10.1	5.5
Natural Gas	9,878	3,446	13,503,963	123.1	.1	.0	59.9
Other Gases	4,788	5,073	48	-40.0	.0	.0	.0
Hydroelectric	1,670,186	1,868,045	2,767,848	5.8	10.7	18.1	12.3
Other Renewables	4,201,700	3,579,526	4,429,751	.6	26.9	34.6	19.7
Total IPP's & Combined Heat and Power	**7,538,353**	**7,110,622**	**22,534,168**	**12.9**	**48.3**	**68.8**	**100.0**
Coal	549,170	612,223	603,938	1.1	3.5	5.9	2.7
Petroleum	1,863,091	2,485,207	1,229,485	-4.5	11.9	24.1	5.5
Natural Gas	9,878	3,446	13,503,963	123.1	.1	.0	59.9
Other Gases	4,788	5,073	48	-40.0	.0	.0	.0
Nuclear	5,739,866	0	0	NM	36.8	.0	.0
Hydroelectric	3,245,779	3,647,932	2,767,848	-1.8	20.8	35.3	12.3
Other Renewables	4,201,700	3,579,526	4,429,751	.6	26.9	34.6	19.7
Total Electric Industry	**15,614,272**	**10,333,407**	**22,535,033**	**4.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Maine				
Coal (2002 cents per million Btu)	0.0	0.0	241.0	NM
Average heat value (Btu per pound)	0	0	12,015	NM
Average sulfur Content(percent)	.0	.0	.7	NM
Petroleum (2002 cents per million Btu)	238.2	286.6	388.5	5.6
Average heat value (Btu per gallon)	150,295	151,068	147,876	–.2
Average sulfur Content(percent)	1.3	1.3	1.1	–1.1
Gas (2002 cents per million Btu)	.0	.0	391.3	NM
Average heat value (Btu per cubic foot)	0	0	1,039	NM

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Maine				
Sulfur Dioxide				
Coal	2	3	2	–0.2
Petroleum	6	22	7	1.1
Gas	0	0	*	NM
Other	4	3	5	1.8
Total	13	27	14	1.1
Nitrogen Oxide				
Coal	3	2	1	–9.7
Petroleum	2	4	1	–4.6
Gas	*	*	2	69.7
Other	4	3	4	–.3
Total	10	10	9	–.8
Carbon Dioxide				
Coal	884	701	324	–10.5
Petroleum	1,611	2,372	1,038	–4.8
Gas	11	7	5,908	101.5
Other	77	84	90	1.8
Total	2,584	3,164	7,360	12.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Maine							
Retail Sales (thousand megawatthours)							
Residential	3,872	3,659	4,486	1.6	32.4	30.6	46.5
Commercial	2,868	3,279	3,950	3.6	24.0	27.4	41.0
Industrial	5,040	4,957	1,160	−15.1	42.2	41.4	12.0
Other	172	63	40	−15.0	1.4	.5	.4
Total	11,952	11,959	9,636	−2.4	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	493	479	537	1.0	40.7	41.0	49.1
Commercial	302	350	414	3.6	24.9	30.0	37.8
Industrial	391	324	130	−11.5	32.3	27.7	11.9
Other	25	15	13	−7.1	2.1	1.3	1.2
Total	1,211	1,168	1,095	−1.1	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	12.74	13.10	11.98	−.7	NA	NA	NA
Commercial	10.52	10.68	10.47	*	NA	NA	NA
Industrial	7.75	6.53	11.24	4.2	NA	NA	NA
Other	14.73	23.87	32.82	9.3	NA	NA	NA
Total	10.13	9.77	11.36	1.3	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Maine						
Number of Entities	2	6	0	3	12	23
Number of Retail Customers	28,959	9,816	0	2,443	745,072	786,290
Retail Sales (thousand megawatthours)	611	371	0	43	8,611	9,636
Percentage of Retail Sales	6.34	3.85	.00	.44	89.36	100.00
Revenue from Retail Sales (million 2002 dollars)	575	57	0	10	453	1,095
Percentage of Revenue	52.52	5.19	.00	.88	41.41	100.00
Revenue per Kilowatthour (2002 cents/kWh)	94.09	15.30	.00	22.62	0	11.36

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Maryland		
NERC Region(s)		ECAR/MACC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	11,859	28
Electric Utilities	69	46
Independent Power Producers & Combined Heat and Power	11,790	7
Net Generation (megawatthours)	48,279,088	26
Electric Utilities	30,734	47
Independent Power Producers & Combined Heat and Power	48,248,354	7
Emissions (thousand short tons)		
Sulfur Dioxide	256	14
Nitrogen Oxide	106	16
Carbon Dioxide	34,312	30
Sulfur Dioxide/sq. mile	26	2
Nitrogen Oxide/sq. mile	11	1
Carbon Dioxide/sq. mile	3,510	4
Utility and ESP Retail Electricity Sales (megawatthours)	66,928,026	22
Utility Retail Electricity Sales (megawatthours)	59,271,452	24
ESP Retail Electricity Sales (megawatthours)	7,656,574	8
Direct Use (megawatthours)	-254,035	47
Average Retail Price (cents/kWh)	6.21	31

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Maryland			
1. Chalk Point LLC	Petroleum, Gas, Coal	Mirant Chalk Point LLC	2,429
2. Calvert Cliffs Nuclea	Nuclear	Calvert Cliffs Nuclear PP Inc	1,685
3. Morgantown Generating	Petroleum, Coal	Mirant Mid-Atlantic LLC	1,492
4. Brandon Shores	Petroleum, Coal	Constellation Power Source Gen	1,286
5. Herbert A Wagner	Gas, Petroleum, Coal	Constellation Power Source Gen	1,014
6. Dickerson	Petroleum, Gas, Coal	Mirant Mid-Atlantic LLC	853
7. Conowingo	Hydro	Exelon Generation Co LLC	512
8. C P Crane	Gas, Petroleum, Coal	Constellation Power Source Gen	399
9. Perryman	Gas, Petroleum	Constellation Power Source Gen	360
10. Riverside	Other, Petroleum, Gas	Constellation Power Source Gen	251

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Maryland					
A. Baltimore Gas & Electric Co	31,729,169	12,104,368	7,975,833	11,234,480	414,488
B. Potomac Electric Power Company	10,146,633	5,137,748	4,930,780	9,736	68,369
C. The Potomac Edison Company	9,071,481	2,843,971	1,778,566	4,433,959	14,985
D. Washington Gas Engy Serv Inc	4,190,731	842,777	3,044,540	150,813	152,601
E. Delmarva Power & Light Company	3,965,821	2,023,610	1,507,913	421,952	12,346
Total	59,103,835	22,952,474	19,237,632	16,250,940	662,789
Percentage of Utility Sales	88	89	82	97	79

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Maryland							
Coal	4,628	4,647	0	NM	42.1	39.7	0.0
Petroleum	1,408	1,285	48	-31.3	12.8	11.0	.4
Natural Gas	1,129	1,483	0	NM	10.3	12.7	.0
Dual Fired	1,455	1,481	21	-37.6	13.2	12.6	.2
Nuclear	1,660	1,675	0	NM	15.1	14.3	.0
Hydroelectric	428	530	0	NM	3.9	4.5	.0
Total Electric Utilities	**10,709**	**11,101**	**69**	**-42.9**	**97.4**	**94.8**	**.6**
Coal	60	60	4,897	63.0	.5	.5	41.3
Petroleum	2	2	835	96.0	.0	.0	7.0
Natural Gas	0	79	338	NM	.0	.7	2.9
Other Gases	0	0	152	NM	.0	.0	1.3
Dual Fired	162	343	3,170	39.1	1.5	2.9	26.7
Nuclear	0	0	1,685	NM	.0	.0	14.2
Hydroelectric	0	0	530	NM	.0	.0	4.5
Other Renewables	65	128	183	12.2	.6	1.1	1.5
Total IPP's & Combined Heat and Power	**290**	**612**	**11,790**	**51.0**	**2.6**	**5.2**	**99.4**
Coal	4,688	4,707	4,897	.5	42.6	40.2	41.3
Petroleum	1,410	1,287	883	-5.1	12.8	11.0	7.4
Natural Gas	1,129	1,561	338	-12.5	10.3	13.3	2.9
Other Gases	0	0	152	NM	.0	.0	1.3
Dual Fired	1,618	1,824	3,190	7.8	14.7	15.6	26.9
Nuclear	1,660	1,675	1,685	.2	15.1	14.3	14.2
Hydroelectric	428	530	530	2.4	3.9	4.5	4.5
Other Renewables	65	128	183	12.2	.6	1.1	1.5
Total Electric Industry	**10,998**	**11,713**	**11,859**	**.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Maryland							
Coal	24,890,670	27,394,342	0	NM	55.3	58.7	0.0
Petroleum	3,953,777	1,478,623	30,734	–41.7	8.8	3.2	.1
Natural Gas	684,750	878,598	0	NM	1.5	1.9	.0
Nuclear	12,300,816	13,212,967	0	NM	27.3	28.3	.0
Hydroelectric	1,658,271	1,588,375	0	NM	3.7	3.4	.0
Total Electric Utilities	**43,488,284**	**44,552,905**	**30,734**	**–55.3**	**96.7**	**95.4**	**.1**
Coal	236,309	226,583	28,712,053	70.5	.5	.5	59.5
Petroleum	211,013	86,387	2,251,698	30.1	.5	.2	4.7
Natural Gas	87,554	533,988	2,214,431	43.2	.2	1.1	4.6
Other Gases	475,788	564,035	504,513	.7	1.1	1.2	1.0
Nuclear	0	0	12,128,005	NM	.0	.0	25.1
Hydroelectric	0	0	1,660,989	NM	.0	.0	3.4
Other Renewables	478,940	743,497	776,665	5.5	1.1	1.6	1.6
Total IPP's & Combined Heat and Power	**1,489,604**	**2,154,491**	**48,248,354**	**47.2**	**3.3**	**4.6**	**99.9**
Coal	25,126,979	27,620,925	28,712,053	1.5	55.9	59.1	59.5
Petroleum	4,164,790	1,565,010	2,282,432	–6.5	9.3	3.4	4.7
Natural Gas	772,304	1,412,586	2,214,431	12.4	1.7	3.0	4.6
Other Gases	475,788	564,035	504,513	.7	1.1	1.2	1.0
Nuclear	12,300,816	13,212,967	12,128,005	–.2	27.3	28.3	25.1
Hydroelectric	1,658,271	1,588,375	1,660,989	.0	3.7	3.4	3.4
Other Renewables	478,940	743,497	776,665	5.5	1.1	1.6	1.6
Total Electric Industry	**44,977,888**	**46,707,396**	**48,279,088**	**.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Maryland				
Coal (2002 cents per million Btu)	178.2	154.2	–	NA
Average heat value (Btu per pound)	12,752	12,913	–	NA
Average sulfur Content(percent)	1.3	1.1	–	NA
Petroleum (2002 cents per million Btu)	255.2	304.6	–	NA
Average heat value (Btu per gallon)	150,580	150,922	–	NA
Average sulfur Content(percent)	1.5	1.1	–	NA
Gas (2002 cents per million Btu)	322.0	293.2	–	NA
Average heat value (Btu per cubic foot)	1,041	1,041	–	NA

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Maryland				
Sulfur Dioxide				
Coal	240	254	249	0.4
Petroleum	33	10	6	-16.6
Gas	*	0	*	2.4
Other	1	1	1	-5.5
Total	274	265	256	-.7
Nitrogen Oxide				
Coal	88	106	72	-2.2
Petroleum	6	3	3	-8.2
Gas	29	4	30	.6
Other	1	1	2	8.0
Total	123	114	106	-1.6
Carbon Dioxide				
Coal	25,086	27,754	29,981	2.0
Petroleum	4,316	1,656	2,143	-7.5
Gas	1,176	1,374	2,029	6.3
Other	63	145	158	10.7
Total	30,641	30,929	34,312	1.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Maryland							
Retail Sales (thousand megawatthours)							
Residential	21,546	21,937	25,770	2.0	40.0	39.0	38.5
Commercial	11,317	23,419	23,578	8.5	21.0	41.6	35.2
Industrial	20,201	10,128	16,740	-2.1	37.5	18.0	25.0
Other	809	781	841	.4	1.5	1.4	1.3
Total	53,872	56,264	66,928	2.4	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,971	1,877	1,986	.1	47.2	46.5	47.8
Commercial	904	1,651	1,436	5.3	21.6	40.9	34.5
Industrial	1,225	438	650	-6.8	29.3	10.8	15.6
Other	75	71	86	1.5	1.8	1.8	2.1
Total	4,175	4,037	4,158	*	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	9.15	8.56	7.71	-1.9	NA	NA	NA
Commercial	7.99	7.05	6.09	-3.0	NA	NA	NA
Industrial	6.07	4.32	3.88	-4.8	NA	NA	NA
Other	9.22	9.04	10.18	1.1	NA	NA	NA
Total	7.75	7.17	6.21	-2.4	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Maryland						
Number of Entities	2	7	0	3	7	19
Number of Retail Customers	1,385,839	646,169	0	169,779	69,984	2,271,771
Retail Sales (thousand megawatthours)	40,801	14,854	0	3,616	7,657	66,928
Percentage of Retail Sales	60.96	22.19	.00	5.40	11.44	100.00
Revenue from Retail Sales (million 2002 dollars)	2,388	1,169	0	267	334	4,158
Percentage of Revenue	57.44	28.11	.00	6.43	8.03	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.85	7.87	.00	7.39	0	6.21

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Massachusetts		
NERC Region(s)		NPCC
Primary Energy Source		Gas
Net Summer Capability (megawatts)	12,159	27
Electric Utilities	1,090	44
Independent Power Producers & Combined Heat and Power	11,069	9
Net Generation (megawatthours)	42,015,689	34
Electric Utilities	1,156,651	45
Independent Power Producers & Combined Heat and Power	40,859,038	8
Emissions (thousand short tons)		
Sulfur Dioxide	97	26
Nitrogen Oxide	38	38
Carbon Dioxide	25,699	33
Sulfur Dioxide/sq. mile	12	8
Nitrogen Oxide/sq. mile	5	11
Carbon Dioxide/sq. mile	3,279	6
Utility and ESP Retail Electricity Sales (megawatthours)	52,409,743	25
Utility Retail Electricity Sales (megawatthours)	43,879,763	29
ESP Retail Electricity Sales (megawatthours)	8,529,980	7
Direct Use (megawatthours)	−1,300,511	50
Average Retail Price (cents/kWh)	10.18	8

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Massachusetts			
1. Brayton Point	Gas, Petroleum, Coal	U S Gen New England Inc	1,538
2. Canal	Gas, Petroleum	Mirant Canal LLC	1,112
3. Northfield Mountain	Hydro	Northeast Generation Co	1,080
4. Mystic Generating Sta	Gas, Petroleum	Exelon New England Holdings LLC	778
5. Salem Harbor	Petroleum, Coal	U S Gen New England Inc	712
6. Pilgrim Nuclear Power	Nuclear	Entergy Nuclear Generation Co	667
7. Bear Swamp	Hydro	U S Gen New England Inc	570
8. Stony Brook	Petroleum, Gas	Massachusetts Mun Whls Elec Co	531
9. ANP Bellingham Energy	Petroleum, Gas	ANP Bellingham Energy Co	447
10. ANP Blackstone Energy	Gas	ANP Blackstone Energy Co	444

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Massachusetts					
A. Massachusetts Electric Company	17,145,737	8,056,404	6,505,182	2,532,104	52,047
B. Boston Edison Company	10,724,435	3,958,034	5,876,260	783,552	106,589
C. Western Massachusetts Elec Co	3,319,632	1,446,053	1,195,187	651,501	26,891
D. Commonwealth Electric Company	3,245,928	1,797,977	1,285,226	150,759	11,966
E. New Energy Ventures, Inc	3,173,115	0	3,173,115	0	0
Total	37,608,847	15,258,468	18,034,970	4,117,916	197,493
Percentage of Utility Sales	72	82	76	45	18

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Massachusetts							
Coal	1,679	1,737	145	-23.8	15.4	15.3	1.2
Petroleum	2,691	1,941	305	-21.5	24.6	17.1	2.5
Natural Gas	18	870	27	4.7	.2	7.7	.2
Dual Fired	2,552	2,370	569	-15.4	23.4	20.9	4.7
Nuclear	665	669	0	NM	6.1	5.9	.0
Hydroelectric	1,856	1,855	44	-34.1	17.0	16.4	.4
Other Renewables	*	*	0	NM	.0	.0	.0
Total Electric Utilities	**9,461**	**9,442**	**1,090**	**-21.3**	**86.6**	**83.4**	**9.0**
Coal	31	10	1,544	54.4	.3	.1	12.7
Petroleum	50	122	1,724	48.2	.5	1.1	14.2
Natural Gas	152	429	2,188	34.5	1.4	3.8	18.0
Dual Fired	867	929	2,783	13.8	7.9	8.2	22.9
Nuclear	0	0	667	NM	.0	.0	5.5
Hydroelectric	59	58	1,859	46.8	.5	.5	15.3
Other Renewables	306	337	305	.0	2.8	3.0	2.5
Total IPP's & Combined Heat and Power	**1,465**	**1,886**	**11,069**	**25.2**	**13.4**	**16.6**	**91.0**
Coal	1,710	1,747	1,689	-.1	15.6	15.4	13.9
Petroleum	2,741	2,063	2,029	-3.3	25.1	18.2	16.7
Natural Gas	170	1,299	2,215	33.0	1.6	11.5	18.2
Dual Fired	3,418	3,299	3,351	-.2	31.3	29.1	27.6
Nuclear	665	669	667	.0	6.1	5.9	5.5
Hydroelectric	1,915	1,913	1,903	-.1	17.5	16.9	15.6
Other Renewables	306	337	305	-.1	2.8	3.0	2.5
Total Electric Industry	**10,925**	**11,328**	**12,159**	**1.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Massachusetts							
Coal	9,815,909	12,488,802	0	NM	26.5	27.8	0.0
Petroleum	11,112,574	11,586,081	220,435	−35.3	30.0	25.8	.5
Natural Gas	2,897,352	5,213,021	728,570	−14.2	7.8	11.6	1.7
Nuclear	4,338,685	4,310,431	0	NM	11.7	9.6	.0
Hydroelectric	−976	300,362	207,646	NA	.0	.7	.5
Total Electric Utilities	**28,163,544**	**33,898,697**	**1,156,651**	**−29.9**	**76.0**	**75.4**	**2.8**
Coal	114,485	37,654	11,502,861	66.9	.3	.1	27.4
Petroleum	479,277	226,337	6,579,860	33.8	1.3	.5	15.7
Natural Gas	6,152,756	8,413,150	15,140,405	10.5	16.6	18.7	36.0
Nuclear	0	0	5,768,766	NM	.0	.0	13.7
Hydroelectric	204,540	243,147	−187,500	NA	.6	.5	−.4
Other Renewables	1,964,605	2,146,346	2,050,777	.5	5.3	4.8	4.9
Other	0	0	3,869	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**8,915,663**	**11,066,633**	**40,859,038**	**18.4**	**24.0**	**24.6**	**97.2**
Coal	9,930,394	12,526,456	11,502,861	1.6	26.8	27.9	27.4
Petroleum	11,591,851	11,812,418	6,800,295	−5.8	31.3	26.3	16.2
Natural Gas	9,050,108	13,626,171	15,868,975	6.4	24.4	30.3	37.8
Nuclear	4,338,685	4,310,431	5,768,766	3.2	11.7	9.6	13.7
Hydroelectric	203,564	543,509	20,146	−22.7	.5	1.2	.0
Other Renewables	1,964,605	2,146,346	2,050,777	.5	5.3	4.8	4.9
Other	0	0	3,869	NM	.0	.0	.0
Total Electric Industry	**37,079,207**	**44,965,330**	**42,015,689**	**1.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Massachusetts				
Coal (2002 cents per million Btu)	186.8	174.6	191.9	0.3
Average heat value (Btu per pound)	12,951	12,571	12,501	−.4
Average sulfur Content(percent)	1.0	.7	.7	−4.9
Petroleum (2002 cents per million Btu)	291.8	267.9	354.9	2.2
Average heat value (Btu per gallon)	151,281	151,641	150,202	−.1
Average sulfur Content(percent)	1.5	1.1	.9	−5.7
Gas (2002 cents per million Btu)	293.1	309.3	351.4	2.0
Average heat value (Btu per cubic foot)	1,034	1,033	1,019	−.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Massachusetts				
Sulfur Dioxide				
Coal	77	74	62	–2.3
Petroleum	71	71	34	–7.8
Gas	*	*	*	.8
Other	1	1	1	4.0
Total	149	145	97	–4.6
Nitrogen Oxide				
Coal	31	24	21	–4.1
Petroleum	11	14	7	–4.6
Gas	8	12	5	–4.9
Other	3	4	4	2.7
Total	53	54	38	–3.8
Carbon Dioxide				
Coal	9,774	12,396	11,665	2.0
Petroleum	10,231	9,563	5,904	–5.9
Gas	4,679	7,175	7,754	5.8
Other	371	419	375	.1
Total	25,054	29,552	25,699	.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Massachusetts							
Retail Sales (thousand megawatthours)							
Residential	15,785	16,274	18,548	1.8	34.9	34.1	35.4
Commercial	18,897	20,834	23,680	2.5	41.7	43.7	45.2
Industrial	9,605	9,930	9,077	–.6	21.2	20.8	17.3
Other	994	622	1,105	1.2	2.2	1.3	2.1
Total	45,281	47,659	52,410	1.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,935	1,938	2,034	.6	38.4	37.8	38.1
Commercial	2,036	2,204	2,400	1.8	40.4	42.9	45.0
Industrial	927	896	796	–1.7	18.4	17.5	14.9
Other	135	93	108	–2.4	2.7	1.8	2.0
Total	5,033	5,131	5,338	.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	12.26	11.91	10.97	–1.2	NA	NA	NA
Commercial	10.77	10.58	10.14	–.7	NA	NA	NA
Industrial	9.65	9.02	8.77	–1.1	NA	NA	NA
Other	13.60	14.89	9.79	–3.6	NA	NA	NA
Total	11.12	10.77	10.18	–1.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Massachusetts						
Number of Entities	7	40	0	0	8	55
Number of Retail Customers	2,470,435	384,759	0	0	35,324	2,890,518
Retail Sales (thousand megawatthours)	36,469	7,410	0	0	8,530	52,410
Percentage of Retail Sales	69.59	14.14	.00	.00	16.28	100.00
Revenue from Retail Sales (million 2002 dollars)	4,194	706	0	0	438	5,338
Percentage of Revenue	78.58	13.22	.00	.00	8.20	100.00
Revenue per Kilowatthour (2002 cents/kWh)	11.50	9.52	.00	.00	0	10.18

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Michigan		
NERC Region(s)		ECAR/MAPP/MAIN
Primary Energy Source		Coal
Net Summer Capability (megawatts)	29,335	9
Electric Utilities	23,279	9
Independent Power Producers & Combined Heat and Power	6,056	13
Net Generation (megawatthours)	117,889,087	12
Electric Utilities	100,451,718	8
Independent Power Producers & Combined Heat and Power	17,437,370	15
Emissions (thousand short tons)		
Sulfur Dioxide	355	12
Nitrogen Oxide	154	13
Carbon Dioxide	79,781	11
Sulfur Dioxide/sq. mile	6	19
Nitrogen Oxide/sq. mile	3	18
Carbon Dioxide/sq. mile	1,404	20
Utility and ESP Retail Electricity Sales (megawatthours)	107,310,696	10
Utility Retail Electricity Sales (megawatthours)	102,810,494	10
ESP Retail Electricity Sales (megawatthours)	4,500,202	10
Direct Use (megawatthours)	2,811,015	14
Average Retail Price (cents/kWh)	6.92	19

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Michigan			
1. Monroe	Petroleum, Coal	Detroit Edison Co	3,034
2. Donald C Cook	Nuclear	Indiana Michigan Power Co	2,060
3. Ludington	Hydro	Consumers Energy Co	1,872
4. Midland Cogeneration	Gas	Midland Cogeneration Venture	1,808
5. Dan E Karn	Petroleum, Gas, Coal	Consumers Energy Co	1,787
6. St Clair	Gas, Petroleum, Coal	Detroit Edison Co	1,690
7. Belle River	Petroleum, Gas, Coal	Detroit Edison Co	1,499
8. J H Campbell	Petroleum, Coal	Consumers Energy Co	1,448
9. Fermi	Petroleum, Nuclear	Detroit Edison Co	1,162
10. Greenwood	Petroleum, Gas	Detroit Edison Co	1,010

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Michigan					
A. Detroit Edison Company	48,345,861	15,957,874	18,395,314	13,589,485	403,188
B. Consumers Energy Company	35,746,492	12,698,034	11,361,137	11,453,899	233,422
C. Indiana Michigan Power Co	3,039,931	1,196,874	751,232	1,079,556	12,269
D. Quest Energy LLC	2,748,187	0	1,462,970	1,285,217	0
E. Wisconsin Electric Power Co	2,711,308	164,576	146,120	2,398,275	2,337
Total	92,591,779	30,017,358	32,116,773	29,806,432	651,216
Percentage of Utility Sales	86	87	85	88	68

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Michigan							
Coal	11,929	11,796	11,627	-0.3	47.4	47.5	39.6
Petroleum	1,505	2,367	1,567	.5	6.0	9.5	5.3
Natural Gas	403	405	2,132	20.3	1.6	1.6	7.3
Other Gases	282	11	0	NM	1.1	.0	.0
Dual Fired	2,128	1,280	1,913	-1.2	8.5	5.2	6.5
Nuclear	3,967	3,922	3,938	-.1	15.8	15.8	13.4
Hydroelectric	2,200	2,129	2,101	-.5	8.7	8.6	7.2
Total Electric Utilities	**22,412**	**21,909**	**23,279**	**.4**	**89.0**	**88.1**	**79.4**
Coal	643	636	354	-6.4	2.6	2.6	1.2
Petroleum	2	2	43	37.6	.0	.0	.1
Natural Gas	1,651	1,782	5,157	13.5	6.6	7.2	17.6
Dual Fired	88	79	87	-.1	.3	.3	.3
Hydroelectric	26	26	27	.3	.1	.1	.1
Other Renewables	346	426	388	1.3	1.4	1.7	1.3
Total IPP's & Combined Heat and Power	**2,757**	**2,950**	**6,056**	**9.1**	**11.0**	**11.9**	**20.6**
Coal	12,572	12,432	11,981	-.5	49.9	50.0	40.8
Petroleum	1,507	2,369	1,610	.7	6.0	9.5	5.5
Natural Gas	2,054	2,186	7,289	15.1	8.2	8.8	24.8
Other Gases	282	11	0	NM	1.1	.0	.0
Dual Fired	2,215	1,359	2,000	-1.1	8.8	5.5	6.8
Nuclear	3,967	3,922	3,938	-.1	15.8	15.8	13.4
Hydroelectric	2,226	2,154	2,129	-.5	8.8	8.7	7.3
Other Renewables	346	426	388	1.3	1.4	1.7	1.3
Total Electric Industry	**25,169**	**24,859**	**29,335**	**1.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Michigan							
Coal	61,558,991	65,552,021	65,389,899	0.7	57.9	61.3	55.5
Petroleum	619,777	602,053	1,090,767	6.5	.6	.6	.9
Natural Gas	680,194	838,412	2,336,031	14.7	.6	.8	2.0
Nuclear	28,525,000	21,913,808	31,087,454	1.0	26.8	20.5	26.4
Hydroelectric	866,145	658,322	522,382	−5.5	.8	.6	.4
Other Renewables	0	0	25,185	NM	.0	.0	.0
Total Electric Utilities	**92,250,107**	**89,564,616**	**100,451,718**	**1.0**	**86.7**	**83.7**	**85.2**
Coal	2,400,090	1,892,829	1,309,610	−6.5	2.3	1.8	1.1
Petroleum	141,798	155,600	12,718	−23.5	.1	.1	.0
Natural Gas	9,340,020	12,549,899	13,517,387	4.2	8.8	11.7	11.5
Other Gases	3,371	959	10,108	13.0	.0	.0	.0
Hydroelectric	122,483	119,758	111,310	−1.1	.1	.1	.1
Other Renewables	2,073,571	2,668,976	2,476,219	2.0	1.9	2.5	2.1
Other	37,112	18,122	18	−57.2	.0	.0	.0
Total IPP's & Combined Heat and Power	**14,118,445**	**17,406,144**	**17,437,370**	**2.4**	**13.3**	**16.3**	**14.8**
Coal	63,959,081	67,444,850	66,699,509	.5	60.1	63.0	56.6
Petroleum	761,575	757,653	1,103,485	4.2	.7	.7	.9
Natural Gas	10,020,214	13,388,311	15,853,418	5.2	9.4	12.5	13.4
Other Gases	3,371	959	10,108	13.0	.0	.0	.0
Nuclear	28,525,000	21,913,808	31,087,454	1.0	26.8	20.5	26.4
Hydroelectric	988,628	778,080	633,692	−4.8	.9	.7	.5
Other Renewables	2,073,571	2,668,976	2,501,404	2.1	1.9	2.5	2.1
Other	37,112	18,122	18	−57.2	.0	.0	.0
Total Electric Industry	**106,368,552**	**106,970,760**	**117,889,087**	**1.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Michigan				
Coal (2002 cents per million Btu)	170.4	140.7	131.7	−2.8
Average heat value (Btu per pound)	10,853	10,566	9,991	−.9
Average sulfur Content(percent)	.7	.7	.6	−1.9
Petroleum (2002 cents per million Btu)	340.9	317.2	273.8	−2.4
Average heat value (Btu per gallon)	147,229	135,205	146,871	*
Average sulfur Content(percent)	.9	1.6	1.9	9.0
Gas (2002 cents per million Btu)	269.4	263.4	352.1	3.0
Average heat value (Btu per cubic foot)	379	310	1,007	11.5

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Michigan				
Sulfur Dioxide				
Coal	372	421	350	-0.7
Petroleum	5	7	4	-4.6
Gas	*	*	*	1.7
Other	2	2	2	-2.1
Total	380	430	355	-.8
Nitrogen Oxide				
Coal	291	188	135	-8.2
Petroleum	1	1	1	-6.7
Gas	10	13	13	3.6
Other	3	4	5	7.3
Total	304	207	154	-7.3
Carbon Dioxide				
Coal	67,051	71,693	70,623	.6
Petroleum	822	838	1,082	3.1
Gas	5,294	7,088	7,977	4.7
Other	50	86	100	7.9
Total	73,217	79,705	79,781	1.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Michigan							
Retail Sales (thousand megawatthours)							
Residential	26,770	28,726	34,336	2.8	30.6	29.5	32.0
Commercial	28,930	32,411	37,969	3.1	33.0	33.3	35.4
Industrial	30,572	35,430	34,046	1.2	34.9	36.4	31.7
Other	1,317	824	960	-3.4	1.5	.8	.9
Total	87,589	97,391	107,311	2.3	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	2,433	2,530	2,845	1.8	34.9	35.9	38.3
Commercial	2,583	2,610	2,794	.9	37.1	37.1	37.6
Industrial	1,818	1,809	1,684	-.8	26.1	25.7	22.7
Other	134	92	100	-3.2	1.9	1.3	1.3
Total	6,969	7,041	7,423	.7	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	9.09	8.81	8.28	-1.0	NA	NA	NA
Commercial	8.93	8.05	7.36	-2.1	NA	NA	NA
Industrial	5.95	5.11	4.95	-2.0	NA	NA	NA
Other	10.19	11.18	10.43	.3	NA	NA	NA
Total	7.96	7.23	6.92	-1.5	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Michigan						
Number of Entities	8	44	0	9	6	67
Number of Retail Customers	3,989,397	450,696	0	241,973	16,947	4,699,013
Retail Sales (thousand megawatthours)	88,973	11,548	0	2,289	4,500	107,311
Percentage of Retail Sales	82.91	10.76	.00	2.13	4.19	100.00
Revenue from Retail Sales (million 2002 dollars)	6,253	729	0	212	229	7,423
Percentage of Revenue	84.23	9.82	.00	2.86	3.09	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.03	6.32	.00	9.28	0	6.92

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Minnesota		
NERC Region(s)		MAPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	11,287	30
Electric Utilities	10,329	22
Independent Power Producers & Combined Heat and Power	958	38
Net Generation (megawatthours)	52,777,966	25
Electric Utilities	48,568,719	21
Independent Power Producers & Combined Heat and Power	4,209,247	32
Emissions (thousand short tons)		
Sulfur Dioxide	111	25
Nitrogen Oxide	98	19
Carbon Dioxide	40,009	27
Sulfur Dioxide/sq. mile	1	34
Nitrogen Oxide/sq. mile	1	30
Carbon Dioxide/sq. mile	503	36
Utility and ESP Retail Electricity Sales (megawatthours)	62,162,361	24
Utility Retail Electricity Sales (megawatthours)	62,162,361	23
Direct Use (megawatthours)	2,701,154	16
Average Retail Price (cents/kWh)	5.84	36

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Minnesota			
1. Sherburne County	Petroleum, Coal	Northern States Power Co	2,292
2. Prairie Island	Nuclear	Northern States Power Co	1,049
3. Clay Boswell	Petroleum, Coal	Minnesota Power Inc	914
4. Monticello	Nuclear	Northern States Power Co	597
5. Allen S King	Gas, Petroleum, Coal	Northern States Power Co	571
6. Black Dog	Petroleum, Gas, Coal	Northern States Power Co	548
7. Lakefield Junction	Petroleum, Gas	Great River Energy	487
8. Pleasant Valley	Petroleum, Gas	Great River Energy	421
9. Riverside	Gas, Petroleum, Coal	Northern States Power Co	384
10. Inver Hills	Gas	Northern States Power Co	351

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Minnesota					
A. Northern States Power Company	30,177,176	8,487,493	12,080,327	9,369,198	240,158
B. Minnesota Power, Inc.	8,779,771	960,107	1,127,782	6,616,799	75,083
C. Otter Tail Power Company	1,908,089	502,102	989,506	383,160	33,321
D. Connexus Energy	1,693,572	1,017,852	584,482	72,640	18,598
E. Dakota Electric Association	1,626,875	834,273	299,415	478,464	14,723
Total	44,185,483	11,801,827	15,081,512	16,920,261	381,883
Percentage of Utility Sales	71	58	78	79	52

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Minnesota							
Coal	5,708	5,811	5,726	0.0	60.3	57.1	50.7
Petroleum	915	1,011	943	.3	9.7	9.9	8.4
Natural Gas	128	291	294	9.6	1.4	2.9	2.6
Dual Fired	329	264	1,420	17.6	3.5	2.6	12.6
Nuclear	1,554	1,572	1,646	.6	16.4	15.4	14.6
Hydroelectric	144	142	134	–.8	1.5	1.4	1.2
Other Renewables	85	126	166	7.7	.9	1.2	1.5
Total Electric Utilities	**8,864**	**9,216**	**10,329**	**1.7**	**93.7**	**90.6**	**91.5**
Coal	345	349	158	–8.3	3.6	3.4	1.4
Petroleum	14	20	29	8.3	.2	.2	.3
Natural Gas	30	29	133	17.9	.3	.3	1.2
Dual Fired	27	300	172	22.9	.3	2.9	1.5
Hydroelectric	64	72	42	–4.6	.7	.7	.4
Other Renewables	115	191	412	15.2	1.2	1.9	3.7
Other	0	0	11	NM	.0	.0	.1
Total IPP's & Combined Heat and Power	**595**	**961**	**958**	**5.4**	**6.3**	**9.4**	**8.5**
Coal	6,053	6,159	5,885	–.3	64.0	60.5	52.1
Petroleum	929	1,031	973	.5	9.8	10.1	8.6
Natural Gas	159	320	427	11.6	1.7	3.1	3.8
Dual Fired	356	564	1,592	18.1	3.8	5.5	14.1
Nuclear	1,554	1,572	1,646	.6	16.4	15.4	14.6
Hydroelectric	208	214	176	–1.8	2.2	2.1	1.6
Other Renewables	200	317	578	12.5	2.1	3.1	5.1
Other	0	0	11	NM	.0	.0	.1
Total Electric Industry	**9,459**	**10,177**	**11,287**	**2.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Minnesota							
Coal	27,110,850	27,081,067	32,200,713	1.9	61.6	62.6	61.0
Petroleum	630,166	763,764	640,129	.2	1.4	1.8	1.2
Natural Gas	279,415	511,966	897,018	13.8	.6	1.2	1.7
Nuclear	11,986,053	10,819,172	13,684,824	1.5	27.2	25.0	25.9
Hydroelectric	833,736	697,224	736,795	–1.4	1.9	1.6	1.4
Other Renewables	413,881	429,333	409,240	–.1	.9	1.0	.8
Total Electric Utilities	**41,254,101**	**40,302,526**	**48,568,719**	**1.8**	**93.7**	**93.2**	**92.0**
Coal	1,541,512	1,520,639	1,719,496	1.2	3.5	3.5	3.3
Petroleum	7,738	73,623	12,662	5.6	.0	.2	.0
Natural Gas	233,278	260,798	694,935	12.9	.5	.6	1.3
Hydroelectric	317,072	337,474	72,290	–15.1	.7	.8	.1
Other Renewables	686,934	745,237	1,667,855	10.4	1.6	1.7	3.2
Other	0	0	42,010	NM	.0	.0	.1
Total IPP's & Combined Heat and Power	**2,786,533**	**2,937,770**	**4,209,247**	**4.7**	**6.3**	**6.8**	**8.0**
Coal	28,652,362	28,601,706	33,920,209	1.9	65.1	66.1	64.3
Petroleum	637,904	837,387	652,790	.3	1.4	1.9	1.2
Natural Gas	512,693	772,764	1,591,953	13.4	1.2	1.8	3.0
Nuclear	11,986,053	10,819,172	13,684,824	1.5	27.2	25.0	25.9
Hydroelectric	1,150,808	1,034,698	809,085	–3.8	2.6	2.4	1.5
Other Renewables	1,100,815	1,174,570	2,077,095	7.3	2.5	2.7	3.9
Other	0	0	42,010	NM	.0	.0	.1
Total Electric Industry	**44,040,634**	**43,240,296**	**52,777,966**	**2.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Minnesota				
Coal (2002 cents per million Btu)	126.5	112.5	106.0	–1.9
Average heat value (Btu per pound)	8,844	8,895	8,818	*
Average sulfur Content(percent)	.4	.4	.4	.3
Petroleum (2002 cents per million Btu)	88.8	80.0	60.1	–4.2
Average heat value (Btu per gallon)	71,632	72,268	131,276	7.0
Average sulfur Content(percent)	5.3	5.6	5.8	.9
Gas (2002 cents per million Btu)	273.2	250.4	373.0	3.5
Average heat value (Btu per cubic foot)	1,008	1,004	1,006	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Minnesota				
Sulfur Dioxide				
Coal	116	123	110	-0.6
Petroleum	*	*	*	.0
Gas	0	0	0	NM
Other	2	3	1	-9.7
Total	119	126	111	-.8
Nitrogen Oxide				
Coal	136	103	94	-4.0
Petroleum	*	*	*	.0
Gas	1	1	1	5.0
Other	3	3	2	-1.5
Total	140	107	98	-3.9
Carbon Dioxide				
Coal	33,503	34,882	38,417	1.5
Petroleum	722	921	637	-1.4
Gas	384	536	900	9.9
Other	51	58	53	.5
Total	34,661	36,397	40,009	1.6

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Minnesota							
Retail Sales (thousand megawatthours)							
Residential	15,597	17,073	20,451	3.1	31.7	30.7	32.9
Commercial	8,535	10,137	19,457	9.6	17.3	18.2	31.3
Industrial	24,384	27,713	21,515	-1.4	49.5	49.8	34.6
Other	694	750	740	.7	1.4	1.3	1.2
Total	49,211	55,674	62,162	2.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,231	1,269	1,531	2.4	40.1	39.6	42.2
Commercial	589	649	1,143	7.6	19.2	20.2	31.5
Industrial	1,194	1,234	900	-3.1	38.9	38.5	24.8
Other	55	55	54	-.2	1.8	1.7	1.5
Total	3,070	3,207	3,630	1.9	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.89	7.43	7.49	-.6	NA	NA	NA
Commercial	6.90	6.40	5.88	-1.8	NA	NA	NA
Industrial	4.90	4.45	4.19	-1.7	NA	NA	NA
Other	7.99	7.32	7.36	-.9	NA	NA	NA
Total	6.24	5.76	5.84	-.7	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Minnesota						
Number of Entities	4	131	0	43	0	178
Number of Retail Customers	1,341,154	395,113	0	636,174	0	2,372,441
Retail Sales (thousand megawatthours)	40,866	10,108	0	11,188	0	62,162
Percentage of Retail Sales	65.74	16.26	.00	18.00	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	2,240	616	0	774	0	3,630
Percentage of Revenue	61.70	16.97	.00	21.32	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	5.48	6.09	.00	6.92	0	5.84

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Mississippi		
NERC Region(s)		SERC/SPP
Primary Energy Source		Gas
Net Summer Capability (megawatts)	13,691	25
Electric Utilities	8,888	26
Independent Power Producers & Combined Heat and Power	4,803	15
Net Generation (megawatthours)	42,900,941	32
Electric Utilities	35,099,283	30
Independent Power Producers & Combined Heat and Power	7,801,659	25
Emissions (thousand short tons)		
Sulfur Dioxide	72	30
Nitrogen Oxide	46	33
Carbon Dioxide	25,545	34
Sulfur Dioxide/sq. mile	2	33
Nitrogen Oxide/sq. mile	1	33
Carbon Dioxide/sq. mile	545	32
Utility and ESP Retail Electricity Sales (megawatthours)	45,451,850	28
Utility Retail Electricity Sales (megawatthours)	45,451,850	27
Direct Use (megawatthours)	2,055,476	19
Average Retail Price (cents/kWh)	6.24	29

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Mississippi			
1. Victor J Daniel Jr	Petroleum, Gas, Coal	Mississippi Power Co	1,965
2. Grand Gulf	Nuclear	Entergy Operations Inc	1,231
3. Baxter Wilson	Petroleum, Gas	Entergy Mississippi Inc	1,215
4. Jack Watson	Gas, Coal	Mississippi Power Co	1,074
5. Batesville Generation	Gas	LSP Energy Ltd Partnership	766
6. Gerald Andrus	Petroleum, Gas	Entergy Mississippi Inc	761
7. Southaven Energy Faci	Gas	Duke Energy Southaven LLC	624
8. Enterprise Energy Fac	Gas	Duke Energy Enterprise LLC	600
9. Attala Generating LLC	Gas	Attala Generating Co LLC	459
10. Hinds Energy Facility	Gas	Duke Energy Hinds LLC	450

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Mississippi					
A. Entergy Mississippi, Inc	12,829,410	5,092,000	4,445,079	2,910,241	382,090
B. Mississippi Power Company	9,403,846	2,300,017	2,902,291	4,161,902	39,636
C. Tennessee Valley Authority	3,005,423	0	0	3,005,423	0
D. Southern Pine Elec Power Assn	1,738,555	870,394	245,123	622,180	858
E. Coast Electric Power Assn	1,462,390	984,841	234,780	219,429	23,340
Total	28,439,624	9,247,252	7,827,273	10,919,175	445,924
Percentage of Utility Sales	63	52	66	73	55

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Mississippi							
Coal	2,238	2,131	2,225	-0.1	30.2	28.3	16.3
Petroleum	31	31	36	1.7	.4	.4	.3
Natural Gas	520	686	2,180	17.3	7.0	9.1	15.9
Dual Fired	3,114	3,112	3,216	.4	42.0	41.3	23.5
Nuclear	1,143	1,200	1,231	.8	15.4	15.9	9.0
Total Electric Utilities	7,045	7,159	8,888	2.6	95.1	94.9	64.9
Coal	0	0	440	NM	.0	.0	3.2
Petroleum	1	1	0	NM	.0	.0	.0
Natural Gas	67	71	4,080	57.9	.9	.9	29.8
Other Gases	0	0	4	NM	.0	.0	.0
Other Renewables	294	310	279	-.6	4.0	4.1	2.0
Total IPP's & Combined Heat and Power	362	382	4,803	33.3	4.9	5.1	35.1
Coal	2,238	2,131	2,665	2.0	30.2	28.3	19.5
Petroleum	32	32	36	1.2	.4	.4	.3
Natural Gas	586	757	6,260	30.1	7.9	10.0	45.7
Other Gases	0	0	4	NM	.0	.0	.0
Dual Fired	3,114	3,112	3,216	.4	42.0	41.3	23.5
Nuclear	1,143	1,200	1,231	.8	15.4	15.9	9.0
Other Renewables	294	310	279	-.6	4.0	4.1	2.0
Total Electric Industry	7,407	7,541	13,691	7.1	100.0	100.0	100.0

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Mississippi							
Coal	8,819,755	12,500,586	12,483,658	3.9	34.0	37.1	29.1
Petroleum	3,545,055	2,633,109	26,357	-42.0	13.7	7.8	.1
Natural Gas	2,965,671	5,281,362	12,529,809	17.4	11.4	15.7	29.2
Nuclear	7,903,547	10,812,562	10,059,459	2.7	30.5	32.1	23.4
Total Electric Utilities	23,234,028	31,227,619	35,099,283	4.7	89.6	92.7	81.8
Coal	60,459	45,948	2,369,485	50.3	.2	.1	5.5
Petroleum	55,485	11,111	3,945	-25.5	.2	.0	.0
Natural Gas	638,976	772,766	4,441,589	24.0	2.5	2.3	10.4
Other Gases	0	0	37,916	NM	.0	.0	.1
Hydroelectric	0	0	12,129	NM	.0	.0	.0
Other Renewables	1,952,578	1,621,509	936,595	-7.8	7.5	4.8	2.2
Total IPP's & Combined Heat and Power	2,707,497	2,451,333	7,801,659	12.5	10.4	7.3	18.2
Coal	8,880,214	12,546,534	14,853,143	5.9	34.2	37.3	34.6
Petroleum	3,600,540	2,644,220	30,302	-41.2	13.9	7.9	.1
Natural Gas	3,604,647	6,054,128	16,971,398	18.8	13.9	18.0	39.6
Other Gases	0	0	37,916	NM	.0	.0	.1
Nuclear	7,903,547	10,812,562	10,059,459	2.7	30.5	32.1	23.4
Hydroelectric	0	0	12,129	NM	.0	.0	.0
Other Renewables	1,952,578	1,621,509	936,595	-7.8	7.5	4.8	2.2
Total Electric Industry	25,941,525	33,678,952	42,900,941	5.7	100.0	100.0	100.0

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Mississippi				
Coal (2002 cents per million Btu)	183.0	159.0	159.5	-1.5
Average heat value (Btu per pound)	12,338	10,486	9,576	-2.8
Average sulfur Content(percent)	1.4	.7	.6	-8.5
Petroleum (2002 cents per million Btu)	196.4	276.5	427.7	9.0
Average heat value (Btu per gallon)	153,438	156,868	140,924	-.9
Average sulfur Content(percent)	2.7	2.2	1.4	-7.4
Gas (2002 cents per million Btu)	269.4	269.5	346.4	2.8
Average heat value (Btu per cubic foot)	1,022	1,036	1,026	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Mississippi				
Sulfur Dioxide				
Coal	89	76	57	-4.8
Petroleum	53	37	*	-51.8
Gas	0	0	*	NM
Other	6	5	4	-2.7
Total	147	118	62	-9.2
Nitrogen Oxide				
Coal	33	30	30	-.8
Petroleum	6	9	*	-46.8
Gas	6	13	15	10.5
Other	2	1	1	-4.3
Total	46	54	46	.1
Carbon Dioxide				
Coal	9,524	13,206	15,689	5.7
Petroleum	3,064	2,279	31	-39.9
Gas	2,827	4,976	9,825	14.8
Total	15,415	20,461	25,545	5.8

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Mississippi							
Retail Sales (thousand megawatthours)							
Residential	13,200	14,817	17,844	3.4	38.0	37.0	39.3
Commercial	6,685	9,955	11,773	6.5	19.2	24.8	25.9
Industrial	14,229	14,622	15,021	.6	40.9	36.5	33.0
Other	635	694	815	2.8	1.8	1.7	1.8
Total	34,749	40,089	45,452	3.0	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,048	1,069	1,299	2.4	43.8	43.9	45.8
Commercial	555	685	804	4.2	23.2	28.1	28.4
Industrial	728	619	661	−1.1	30.4	25.4	23.3
Other	62	61	71	1.6	2.6	2.5	2.5
Total	2,392	2,435	2,835	1.9	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.94	7.22	7.28	−.9	NA	NA	NA
Commercial	8.30	6.88	6.83	−2.1	NA	NA	NA
Industrial	5.11	4.24	4.40	−1.7	NA	NA	NA
Other	9.69	8.85	8.76	−1.1	NA	NA	NA
Total	6.88	6.07	6.24	−1.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Mississippi						
Number of Entities	2	25	0	24	0	51
Number of Retail Customers	600,277	192,469	0	613,337	0	1,406,083
Retail Sales (thousand megawatthours)	22,233	8,518	0	14,701	0	45,452
Percentage of Retail Sales	48.92	18.74	.00	32.34	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,415	432	0	988	0	2,835
Percentage of Revenue	49.90	15.24	.00	34.86	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.36	5.07	.00	6.72	0	6.24

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Missouri		
NERC Region(s)		SPP/MAIN
Primary Energy Source		Coal
Net Summer Capability (megawatts)	19,803	18
Electric Utilities	18,409	13
Independent Power Producers & Combined Heat and Power	1,394	36
Net Generation (megawatthours)	81,162,198	20
Electric Utilities	79,796,801	14
Independent Power Producers & Combined Heat and Power	1,365,397	42
Emissions (thousand short tons)		
Sulfur Dioxide	246	16
Nitrogen Oxide	142	14
Carbon Dioxide	77,663	12
Sulfur Dioxide/sq. mile	4	25
Nitrogen Oxide/sq. mile	2	22
Carbon Dioxide/sq. mile	1,127	25
Utility and ESP Retail Electricity Sales (megawatthours)	75,000,629	19
Utility Retail Electricity Sales (megawatthours)	75,000,629	19
Direct Use (megawatthours)	284,279	36
Average Retail Price (cents/kWh)	6.09	32

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Missouri			
1. Labadie	Petroleum, Coal	Union Electric Co	2,300
2. Rush Island	Petroleum, Coal	Union Electric Co	1,166
3. New Madrid	Petroleum, Coal	Associated Electric Coop Inc	1,160
4. Callaway	Nuclear	Union Electric Co	1,143
5. Thomas Hill	Petroleum, Coal	Associated Electric Coop Inc	1,120
6. Hawthorn	Gas, Coal	Kansas City Power & Light Co	988
7. Sioux	Other, Petroleum, Coal	Union Electric Co	950
8. Meramec	Petroleum, Gas, Coal	Union Electric Co	931
9. Iatan	Petroleum, Coal	Kansas City Power & Light Co	670
10. Audrain Generating St	Gas	NRG South Central Ops Inc	640

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Missouri					
A. Union Electric Company	32,261,745	12,864,857	13,482,191	5,798,346	116,351
B. Kansas City Power & Light Co	8,186,087	2,453,540	4,075,116	1,593,063	64,368
C. UtiliCorp United, Inc	6,930,424	3,041,865	2,179,856	1,289,371	419,332
D. Empire District Electric Co	3,734,580	1,520,693	1,277,276	847,154	89,457
E. City of Springfield	2,801,483	887,043	1,423,018	451,887	39,535
Total	53,914,319	20,767,998	22,437,457	9,979,821	729,043
Percentage of Utility Sales	72	66	84	65	62

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Missouri							
Coal	10,738	10,920	11,053	0.3	69.1	66.9	55.8
Petroleum	1,026	1,084	1,121	1.0	6.6	6.6	5.7
Natural Gas	312	625	1,551	19.5	2.0	3.8	7.8
Dual Fired	1,122	1,331	2,342	8.5	7.2	8.2	11.8
Nuclear	1,125	1,143	1,143	.2	7.2	7.0	5.8
Hydroelectric	1,110	1,110	1,200	.9	7.1	6.8	6.1
Total Electric Utilities	**15,433**	**16,212**	**18,409**	**2.0**	**99.3**	**99.4**	**93.0**
Coal	102	93	96	–.7	.7	.6	.5
Petroleum	2	8	11	20.4	.0	.0	.1
Natural Gas	6	3	1,265	80.9	.0	.0	6.4
Dual Fired	1	1	23	42.8	.0	.0	.1
Total IPP's & Combined Heat and Power	**111**	**106**	**1,394**	**32.5**	**.7**	**.6**	**7.0**
Coal	10,840	11,014	11,148	.3	69.7	67.5	56.3
Petroleum	1,028	1,092	1,131	1.1	6.6	6.7	5.7
Natural Gas	318	628	2,816	27.4	2.0	3.8	14.2
Dual Fired	1,123	1,331	2,365	8.6	7.2	8.2	11.9
Nuclear	1,125	1,143	1,143	.2	7.2	7.0	5.8
Hydroelectric	1,110	1,110	1,200	.9	7.1	6.8	6.1
Total Electric Industry	**15,544**	**16,318**	**19,803**	**2.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Missouri							
Coal	40,688,696	59,903,073	67,147,996	5.7	76.0	83.9	82.7
Petroleum	634,432	125,449	528,353	–2.0	1.2	.2	.7
Natural Gas	386,378	570,084	2,477,701	22.9	.7	.8	3.1
Nuclear	8,381,333	8,954,604	8,389,629	.0	15.7	12.5	10.3
Hydroelectric	3,110,176	1,478,325	1,197,924	–10.1	5.8	2.1	1.5
Other Renewables	1,253	41,704	55,198	52.3	.0	.1	.1
Total Electric Utilities	**53,202,268**	**71,073,239**	**79,796,801**	**4.6**	**99.3**	**99.6**	**98.3**
Coal	295,264	247,207	286,971	–.3	.6	.3	.4
Petroleum	846	14,073	1,042	2.3	.0	.0	.0
Natural Gas	53,596	28,326	1,066,237	39.4	.1	.0	1.3
Other Renewables	995	11,340	11,147	30.8	.0	.0	.0
Total IPP's & Combined Heat and Power	**350,700**	**300,947**	**1,365,397**	**16.3**	**.7**	**.4**	**1.7**
Coal	40,983,960	60,150,280	67,434,967	5.7	76.5	84.3	83.1
Petroleum	635,278	139,522	529,395	–2.0	1.2	.2	.7
Natural Gas	439,974	598,410	3,543,938	26.1	.8	.8	4.4
Nuclear	8,381,333	8,954,604	8,389,629	.0	15.7	12.5	10.3
Hydroelectric	3,110,176	1,478,325	1,197,924	–10.1	5.8	2.1	1.5
Other Renewables	2,248	53,044	66,345	45.7	.0	.1	.1
Total Electric Industry	**53,552,968**	**71,374,186**	**81,162,198**	**4.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Missouri				
Coal (2002 cents per million Btu)	138.0	96.0	89.6	–4.7
Average heat value (Btu per pound)	9,860	8,994	8,822	–1.2
Average sulfur Content(percent)	1.0	.5	.4	–10.9
Petroleum (2002 cents per million Btu)	126.1	300.0	117.5	–.8
Average heat value (Btu per gallon)	83,796	123,144	134,476	5.4
Average sulfur Content(percent)	4.1	2.4	3.3	–2.3
Gas (2002 cents per million Btu)	258.4	287.2	327.7	2.7
Average heat value (Btu per cubic foot)	1,008	1,006	1,008	.0

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Missouri				
Sulfur Dioxide				
Coal	468	307	246	–6.9
Petroleum	5	4	*	–42.9
Gas	0	0	0	NM
Other	0	*	*	NM
Total	473	311	246	–7.0
Nitrogen Oxide				
Coal	201	199	141	–3.8
Petroleum	2	*	0	NM
Gas	1	1	1	2.4
Other	0	*	*	NM
Total	203	201	142	–3.9
Carbon Dioxide				
Coal	45,017	67,084	75,278	5.9
Petroleum	745	152	593	–2.5
Gas	312	460	1,792	21.4
Total	46,074	67,695	77,663	6.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Missouri							
Retail Sales (thousand megawatthours)							
Residential	24,182	26,595	31,684	3.0	41.3	40.5	42.3
Commercial	19,914	22,825	26,796	3.3	34.0	34.8	35.7
Industrial	13,618	15,267	15,341	1.3	23.2	23.3	20.5
Other	908	985	1,179	2.9	1.5	1.5	1.6
Total	58,622	65,673	75,001	2.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,957	1,937	2,238	1.5	47.3	47.1	49.0
Commercial	1,389	1,408	1,576	1.4	33.6	34.2	34.5
Industrial	715	700	679	–.6	17.3	17.0	14.9
Other	72	69	73	.2	1.7	1.7	1.6
Total	4,132	4,113	4,565	1.1	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.09	7.28	7.06	–1.5	NA	NA	NA
Commercial	6.97	6.17	5.88	–1.9	NA	NA	NA
Industrial	5.25	4.58	4.42	–1.9	NA	NA	NA
Other	7.91	6.95	6.20	–2.7	NA	NA	NA
Total	7.05	6.26	6.09	–1.6	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Missouri						
Number of Entities	0	97	0	39	0	136
Number of Retail Customers	0	2,260,443	0	622,880	0	2,883,323
Retail Sales (thousand megawatthours)	0	61,749	0	13,252	0	75,001
Percentage of Retail Sales	.00	82.33	.00	17.67	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	0	3,788	0	777	0	4,565
Percentage of Revenue	.00	82.97	.00	17.03	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	.00	6.13	.00	5.87	0	6.09

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Montana		
NERC Region(s)		WSCC/MAPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	5,172	40
Electric Utilities	2,232	39
Independent Power Producers & Combined Heat and Power	2,939	26
Net Generation (megawatthours)	25,473,706	41
Electric Utilities	6,726,239	41
Independent Power Producers & Combined Heat and Power	18,747,467	14
Emissions (thousand short tons)		
Sulfur Dioxide	45	38
Nitrogen Oxide	39	37
Carbon Dioxide	18,302	38
Sulfur Dioxide/sq. mile	0	45
Nitrogen Oxide/sq. mile	0	46
Carbon Dioxide/sq. mile	126	46
Utility and ESP Retail Electricity Sales (megawatthours)	12,574,530	41
Utility Retail Electricity Sales (megawatthours)	10,323,186	42
ESP Retail Electricity Sales (megawatthours)	2,251,344	11
Direct Use (megawatthours)	-335,980	48
Average Retail Price (cents/kWh)	5.75	39

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Montana			
1. Colstrip	Gas, Petroleum, Coal	PPL Montana LLC	2,094
2. Libby	Hydro	USCE-North Pacific Division	604
3. Noxon Rapids	Hydro	Avista Corporation	527
4. Hungry Horse	Hydro	U S Bureau of Reclamation	428
5. Yellowtail	Hydro	U S Bureau of Reclamation	287
6. Fort Peck	Hydro	USCE-Missouri River District	212
7. Kerr	Hydro	PPL Montana LLC	190
8. J E Corette Plant	Gas, Coal	PPL Montana LLC	150
9. Thompson Falls	Hydro	PPL Montana LLC	88
10. Ryan	Hydro	PPL Montana LLC	60

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Montana					
A. Montana Power Company	4,872,363	2,028,621	2,372,317	419,587	51,838
B. PPL EnergyPlus LLC	1,563,435	0	0	1,563,435	0
C. Flathead Electric Coop, Inc	1,352,177	528,966	375,334	437,179	10,698
D. Hinson Power Company, Inc	1,139,849	0	0	1,139,849	0
E. MDU Resources Group, Inc	566,208	148,311	200,595	202,497	14,805
Total	9,494,032	2,705,898	2,948,246	3,762,547	77,341
Percentage of Utility Sales	76	67	80	83	24

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Montana							
Coal	2,260	2,294	52	-34.2	45.8	45.3	1.0
Petroleum	0	5	0	NM	.0	.1	.0
Natural Gas	70	0	0	NM	1.4	.0	.0
Dual Fired	50	53	58	1.6	1.0	1.0	1.1
Hydroelectric	2,478	2,591	2,122	-1.7	50.3	51.2	41.0
Other Renewables	13	0	0	NM	.3	.0	.0
Total Electric Utilities	**4,871**	**4,943**	**2,232**	**-8.3**	**98.8**	**97.6**	**43.2**
Coal	39	39	2,244	56.9	.8	.8	43.4
Petroleum	0	61	90	NM	.0	1.2	1.7
Hydroelectric	11	11	595	55.7	.2	.2	11.5
Other Renewables	10	10	11	.5	.2	.2	.2
Total IPP's & Combined Heat and Power	**60**	**121**	**2,939**	**54.0**	**1.2**	**2.4**	**56.8**
Coal	2,299	2,333	2,296	.0	46.6	46.1	44.4
Petroleum	0	66	90	NM	.0	1.3	1.7
Natural Gas	70	0	0	NM	1.4	.0	.0
Dual Fired	50	53	58	1.6	1.0	1.0	1.1
Hydroelectric	2,490	2,602	2,717	1.0	50.5	51.4	52.5
Other Renewables	23	10	11	-8.0	.5	.2	.2
Total Electric Industry	**4,931**	**5,064**	**5,172**	**.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Montana							
Coal	13,774,690	14,409,921	285,747	-35.0	57.7	50.4	1.1
Petroleum	20,885	17,228	720	-31.2	.1	.1	.0
Natural Gas	24,159	31,625	6,747	-13.2	.1	.1	.0
Hydroelectric	9,549,364	13,348,499	6,433,025	-4.3	40.0	46.7	25.3
Other Renewables	78,224	0	0	NM	.3	.0	.0
Total Electric Utilities	**23,447,322**	**27,807,273**	**6,726,239**	**-13.0**	**98.2**	**97.3**	**26.4**
Coal	308,168	206,099	15,052,082	54.0	1.3	.7	59.1
Petroleum	1,184	419,404	468,939	94.4	.0	1.5	1.8
Natural Gas	10,761	16,986	9,932	-.9	.0	.1	.0
Other Gases	0	30,861	19,160	NM	.0	.1	.1
Hydroelectric	64,724	57,995	3,133,884	53.9	.3	.2	12.3
Other Renewables	40,695	48,329	63,470	5.1	.2	.2	.2
Total IPP's & Combined Heat and Power	**425,533**	**779,673**	**18,747,467**	**52.3**	**1.8**	**2.7**	**73.6**
Coal	14,082,858	14,616,020	15,337,829	1.0	59.0	51.1	60.2
Petroleum	22,069	436,632	469,659	40.5	.1	1.5	1.8
Natural Gas	34,920	48,611	16,679	-7.9	.1	.2	.1
Other Gases	0	30,861	19,160	NM	.0	.1	.1
Hydroelectric	9,614,088	13,406,494	9,566,909	-.1	40.3	46.9	37.6
Other Renewables	118,919	48,329	63,470	-6.7	.5	.2	.2
Total Electric Industry	**23,872,855**	**28,586,946**	**25,473,706**	**.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Montana				
Coal (2002 cents per million Btu)	77.3	70.2	60.9	−2.6
Average heat value (Btu per pound)	8,496	8,426	8,461	*
Average sulfur Content(percent)	.7	.7	.6	−.2
Petroleum (2002 cents per million Btu)	585.9	544.1	219.0	−10.3
Average heat value (Btu per gallon)	141,000	141,000	137,748	−.3
Average sulfur Content(percent)	.0	.0	3.7	NM
Gas (2002 cents per million Btu)	298.9	1385.9	357.5	2.0
Average heat value (Btu per cubic foot)	1,165	1,071	1,016	−1.5

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Montana				
Sulfur Dioxide				
Coal	20	20	26	2.6
Petroleum	*	*	19	150.1
Gas	0	0	0	NM
Other	*	*	*	4.4
Total	21	20	45	9.1
Nitrogen Oxide				
Coal	52	36	36	−3.9
Petroleum	*	1	1	66.9
Gas	*	*	2	51.0
Other	*	*	*	6.1
Total	52	37	39	−3.0
Carbon Dioxide				
Coal	16,509	16,967	17,593	.7
Petroleum	24	404	678	45.0
Gas	26	59	32	2.4
Total	16,559	17,429	18,302	1.1

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Montana							
Retail Sales (thousand megawatthours)							
Residential	3,598	3,804	4,030	1.3	27.8	31.9	32.0
Commercial	3,026	3,293	3,707	2.3	23.4	27.6	29.5
Industrial	5,837	4,537	4,511	-2.8	45.1	38.1	35.9
Other	469	284	326	-3.9	3.6	2.4	2.6
Total	12,929	11,917	12,575	-.3	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	231	250	291	2.6	36.8	39.3	40.3
Commercial	172	196	242	3.9	27.3	30.8	33.4
Industrial	202	170	167	-2.1	32.1	26.8	23.1
Other	24	19	23	-.1	3.8	3.1	3.2
Total	629	636	724	1.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	6.43	6.58	7.23	1.3	NA	NA	NA
Commercial	5.68	5.96	6.53	1.6	NA	NA	NA
Industrial	3.46	3.76	3.70	.8	NA	NA	NA
Other	5.02	6.86	7.14	4.0	NA	NA	NA
Total	4.86	5.34	5.75	1.9	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Montana						
Number of Entities	3	8	2	26	4	43
Number of Retail Customers	321,559	25,601	18,229	143,659	915	509,963
Retail Sales (thousand megawatthours)	5,452	1,653	352	2,866	2,251	12,575
Percentage of Retail Sales	43.35	13.15	2.80	22.79	17.90	100.00
Revenue from Retail Sales (million 2002 dollars)	372	57	17	203	74	724
Percentage of Revenue	51.43	7.89	2.42	28.10	10.17	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.83	3.45	4.96	7.10	0	5.75

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Nebraska		
NERC Region(s)		WSCC/MAPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	6,069	37
Electric Utilities	6,052	30
Independent Power Producers & Combined Heat and Power	17	50
Net Generation (megawatthours)	31,618,493	37
Electric Utilities	31,550,226	31
Independent Power Producers & Combined Heat and Power	68,267	50
Emissions (thousand short tons)		
Sulfur Dioxide	68	32
Nitrogen Oxide	47	32
Carbon Dioxide	22,788	36
Sulfur Dioxide/sq. mile	1	36
Nitrogen Oxide/sq. mile	1	41
Carbon Dioxide/sq. mile	296	41
Utility and ESP Retail Electricity Sales (megawatthours)	25,661,061	36
Utility Retail Electricity Sales (megawatthours)	25,661,061	36
Direct Use (megawatthours)	60,256	40
Average Retail Price (cents/kWh)	5.55	45

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Nebraska			
1. Gerald Gentleman	Gas, Coal	Nebraska Public Power District	1,365
2. Cooper	Nuclear	Nebraska Public Power District	758
3. North Omaha	Gas, Coal	Omaha Public Power District	663
4. Nebraska City	Petroleum, Coal	Omaha Public Power District	646
5. Fort Calhoun	Nuclear	Omaha Public Power District	476
6. Sarpy County	Petroleum, Gas	Omaha Public Power District	314
7. Rokeby	Petroleum, Gas	Lincoln Electric System	265
8. Sheldon	Gas, Coal	Nebraska Public Power District	225
9. Lon Wright	Gas, Coal	Fremont City of	120
10. Jones Street	Petroleum	Omaha Public Power District	118

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Nebraska					
A. Omaha Public Power District	8,772,187	3,136,085	3,264,938	2,289,572	81,592
B. Lincoln Electric System	2,926,216	1,057,046	1,053,336	542,708	273,126
C. Nebraska Public Power District	2,913,867	784,530	834,515	1,110,503	184,319
D. Loup River Public Power Dist	992,939	221,889	135,447	585,688	49,915
E. Southern Public Power District	787,825	228,488	30,090	357,979	171,268
Total	16,393,034	5,428,038	5,318,326	4,886,450	760,220
Percentage of Utility Sales	64	61	72	65	43

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Nebraska							
Coal	3,103	3,152	3,196	0.3	56.2	54.6	52.7
Petroleum	250	262	298	2.0	4.5	4.5	4.9
Natural Gas	13	5	2	−19.7	.2	.1	.0
Dual Fired	725	925	1,149	5.3	13.1	16.0	18.9
Nuclear	1,254	1,250	1,234	−.2	22.7	21.7	20.3
Hydroelectric	168	167	167	.0	3.0	2.9	2.8
Other Renewables	0	0	6	NM	.0	.0	.1
Total Electric Utilities	**5,512**	**5,760**	**6,052**	**1.0**	**99.8**	**99.8**	**99.7**
Coal	8	7	8	−.5	.2	.1	.1
Petroleum	0	0	1	NM	.0	.0	.0
Natural Gas	0	1	1	NM	.0	.0	.0
Dual Fired	0	0	2	NM	.0	.0	.0
Other Renewables	0	4	5	NM	.0	.1	.1
Total IPP's & Combined Heat and Power	**8**	**12**	**17**	**8.3**	**.2**	**.2**	**.3**
Coal	3,111	3,159	3,204	.3	56.4	54.7	52.8
Petroleum	250	262	299	2.0	4.5	4.5	4.9
Natural Gas	13	6	3	−14.4	.2	.1	.1
Dual Fired	725	925	1,152	5.3	13.1	16.0	19.0
Nuclear	1,254	1,250	1,234	−.2	22.7	21.7	20.3
Hydroelectric	168	167	167	.0	3.0	2.9	2.8
Other Renewables	0	4	10	NM	.0	.1	.2
Total Electric Industry	**5,520**	**5,772**	**6,069**	**1.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Nebraska							
Coal	14,739,783	17,209,080	19,899,803	3.4	64.8	60.5	62.9
Petroleum	19,035	31,059	18,410	-.4	.1	.1	.1
Natural Gas	152,922	205,991	404,106	11.4	.7	.7	1.3
Other Gases	0	0	101	NM	.0	.0	.0
Nuclear	6,805,133	9,268,857	10,122,242	4.5	29.9	32.6	32.0
Hydroelectric	1,001,663	1,672,419	1,097,486	1.0	4.4	5.9	3.5
Other Renewables	5,750	624	8,078	3.8	.0	.0	.0
Total Electric Utilities	**22,724,286**	**28,388,030**	**31,550,226**	**3.7**	**99.8**	**99.8**	**99.8**
Coal	36,428	39,557	44,104	2.1	.2	.1	.1
Petroleum	0	0	2,139	NM	.0	.0	.0
Natural Gas	143	5,309	9,032	58.6	.0	.0	.0
Other Renewables	0	16,370	12,993	NM	.0	.1	.0
Total IPP's & Combined Heat and Power	**36,570**	**61,236**	**68,267**	**7.2**	**.2**	**.2**	**.2**
Coal	14,776,211	17,248,637	19,943,907	3.4	64.9	60.6	63.1
Petroleum	19,035	31,059	20,549	.9	.1	.1	.1
Natural Gas	153,065	211,300	413,138	11.7	.7	.7	1.3
Other Gases	0	0	101	NM	.0	.0	.0
Nuclear	6,805,133	9,268,857	10,122,242	4.5	29.9	32.6	32.0
Hydroelectric	1,001,663	1,672,419	1,097,486	1.0	4.4	5.9	3.5
Other Renewables	5,750	16,994	21,071	15.5	.0	.1	.1
Total Electric Industry	**22,760,856**	**28,449,266**	**31,618,493**	**3.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Nebraska				
Coal (2002 cents per million Btu)	84.1	60.1	58.1	-4.0
Average heat value (Btu per pound)	8,561	8,595	8,593	*
Average sulfur Content(percent)	.4	.3	.3	-1.8
Petroleum (2002 cents per million Btu)	276.1	462.8	554.8	8.1
Average heat value (Btu per gallon)	107,947	137,568	138,150	2.8
Average sulfur Content(percent)	6.0	.0	.2	-32.7
Gas (2002 cents per million Btu)	304.0	295.1	416.6	3.6
Average heat value (Btu per cubic foot)	976	998	977	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Nebraska				
Sulfur Dioxide				
Coal	58	62	68	1.6
Petroleum	*	*	*	–9.2
Total	58	62	68	1.6
Nitrogen Oxide				
Coal	76	48	47	–5.2
Petroleum	*	*	*	7.4
Gas	*	*	*	6.1
Other	0	*	0	NM
Total	76	49	47	–5.2
Carbon Dioxide				
Coal	16,925	19,728	22,471	3.2
Petroleum	20	33	21	1.0
Gas	108	160	296	11.8
Total	17,053	19,921	22,788	3.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Nebraska							
Retail Sales (thousand megawatthours)							
Residential	7,226	7,989	8,956	2.4	38.5	35.4	34.9
Commercial	5,471	6,500	7,384	3.4	29.2	28.8	28.8
Industrial	4,963	6,580	7,563	4.8	26.5	29.1	29.5
Other	1,089	1,514	1,758	5.5	5.8	6.7	6.8
Total	18,749	22,582	25,661	3.5	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	503	524	603	2.0	43.5	42.6	42.3
Commercial	346	365	415	2.0	29.9	29.7	29.1
Industrial	223	244	294	3.1	19.3	19.9	20.6
Other	85	96	112	3.1	7.3	7.8	7.9
Total	1,157	1,229	1,424	2.3	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	6.96	6.56	6.73	–.4	NA	NA	NA
Commercial	6.32	5.61	5.62	–1.3	NA	NA	NA
Industrial	4.50	3.71	3.89	–1.6	NA	NA	NA
Other	7.79	6.36	6.37	–2.2	NA	NA	NA
Total	6.17	5.44	5.55	–1.2	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Nebraska						
Number of Entities	0	155	0	7	0	162
Number of Retail Customers	0	905,366	0	16,569	0	921,935
Retail Sales (thousand megawatthours)	0	25,183	0	478	0	25,661
Percentage of Retail Sales	.00	98.14	.00	1.86	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	0	1,389	0	35	0	1,424
Percentage of Revenue	.00	97.56	.00	2.44	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	.00	5.52	.00	7.26	0	5.55

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Nevada		
NERC Region(s)		WSCC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	6,856	35
Electric Utilities	5,384	33
Independent Power Producers & Combined Heat and Power	1,472	35
Net Generation (megawatthours)	32,088,935	36
Electric Utilities	25,008,568	35
Independent Power Producers & Combined Heat and Power	7,080,367	28
Emissions (thousand short tons)		
Sulfur Dioxide	49	35
Nitrogen Oxide	46	34
Carbon Dioxide	24,726	35
Sulfur Dioxide/sq. mile	0	42
Nitrogen Oxide/sq. mile	0	43
Carbon Dioxide/sq. mile	225	44
Utility and ESP Retail Electricity Sales (megawatthours)	29,204,272	34
Utility Retail Electricity Sales (megawatthours)	29,204,272	34
Direct Use (megawatthours)	145,166	38
Average Retail Price (cents/kWh)	8.42	12

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Nevada			
1. Mohave	Gas, Coal	Southern California Edison Co	1,580
2. Hoover Dam	Hydro	U S Bureau of Reclamation	1,039
3. Clark	Gas	Nevada Power Co	700
4. Reid Gardner	Petroleum, Coal	Nevada Power Co	556
5. North Valmy	Petroleum, Coal	Sierra Pacific Power Co	522
6. Tracy	Petroleum, Gas	Sierra Pacific Power Co	491
7. El Dorado Energy	Gas	El Dorado Energy LLC	450
8. Tri Center Naniwa Ene	Gas	Naniwa Energy LLC	300
9. Fort Churchill	Petroleum, Gas	Sierra Pacific Power Co	226
10. Sun Peak Project	Gas	Nevada Sun-Peak Ltd Partners	222

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Nevada					
A. Nevada Power Company	17,599,820	7,240,325	3,662,436	6,293,991	403,068
B. Sierra Pacific Power Company	8,198,264	1,856,931	2,687,871	3,641,288	12,174
C. Colorado River Commission	1,431,642	0	676,849	754,793	0
D. Wells Rural Electric Company	654,482	45,958	44,594	556,224	7,706
E. Valley Electric Assn, Inc	340,748	202,510	138,164	0	74
Total	28,224,956	9,345,724	7,209,914	11,246,296	423,022
Percentage of Utility Sales	97	96	96	99	71

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Nevada							
Coal	2,717	2,806	2,658	−0.2	47.3	43.9	38.8
Petroleum	48	45	43	−1.4	.8	.7	.6
Natural Gas	202	502	414	8.3	3.5	7.9	6.0
Dual Fired	1,237	1,243	1,222	−.1	21.5	19.4	17.8
Hydroelectric	1,031	1,046	1,048	.2	18.0	16.4	15.3
Total Electric Utilities	**5,235**	**5,642**	**5,384**	**.3**	**91.2**	**88.3**	**78.5**
Natural Gas	89	154	1,071	31.9	1.5	2.4	15.6
Dual Fired	205	363	222	.9	3.6	5.7	3.2
Hydroelectric	4	4	4	.0	.1	.1	.1
Other Renewables	208	228	168	−2.3	3.6	3.6	2.5
Other	0	0	7	NM	.0	.0	.1
Total IPP's & Combined Heat and Power	**506**	**749**	**1,472**	**12.6**	**8.8**	**11.7**	**21.5**
Coal	2,717	2,806	2,658	−.2	47.3	43.9	38.8
Petroleum	48	45	43	−1.4	.8	.7	.6
Natural Gas	291	656	1,485	19.9	5.1	10.3	21.7
Dual Fired	1,442	1,606	1,444	.0	25.1	25.1	21.1
Hydroelectric	1,035	1,050	1,052	.2	18.0	16.4	15.3
Other Renewables	208	228	168	−2.3	3.6	3.6	2.5
Other	0	0	7	NM	.0	.0	.1
Total Electric Industry	**5,741**	**6,391**	**6,856**	**2.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Nevada							
Coal	15,627,860	15,250,606	16,413,025	0.5	66.5	56.4	51.1
Petroleum	246,506	31,156	25,472	−22.3	1.0	.1	.1
Natural Gas	1,986,014	5,020,560	6,310,687	13.7	8.5	18.6	19.7
Hydroelectric	1,959,953	2,567,451	2,259,384	1.6	8.3	9.5	7.0
Total Electric Utilities	**19,820,333**	**22,869,773**	**25,008,568**	**2.6**	**84.3**	**84.6**	**77.9**
Petroleum	80,475	789	0	NM	.3	.0	.0
Natural Gas	2,047,184	2,537,255	5,899,973	12.5	8.7	9.4	18.4
Other Gases	0	0	44,909	NM	.0	.0	.1
Hydroelectric	12,227	19,523	8,202	−4.3	.1	.1	.0
Other Renewables	1,540,055	1,596,001	1,127,283	−3.4	6.6	5.9	3.5
Other	2,198	8,183	0	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**3,682,138**	**4,161,751**	**7,080,367**	**7.5**	**15.7**	**15.4**	**22.1**
Coal	15,627,860	15,250,606	16,413,025	.5	66.5	56.4	51.1
Petroleum	326,981	31,945	25,472	−24.7	1.4	.1	.1
Natural Gas	4,033,198	7,557,815	12,210,660	13.1	17.2	28.0	38.1
Other Gases	0	0	44,909	NM	.0	.0	.1
Hydroelectric	1,972,180	2,586,974	2,267,586	1.6	8.4	9.6	7.1
Other Renewables	1,540,055	1,596,001	1,127,283	−3.4	6.6	5.9	3.5
Other	2,198	8,183	0	NM	.0	.0	.0
Total Electric Industry	**23,502,471**	**27,031,524**	**32,088,935**	**3.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Nevada				
Coal (2002 cents per million Btu)	163.7	143.1	133.9	-2.2
Average heat value (Btu per pound)	11,012	11,169	10,177	-.9
Average sulfur Content(percent)	.5	.5	.5	.9
Petroleum (2002 cents per million Btu)	399.4	521.7	600.2	4.6
Average heat value (Btu per gallon)	148,546	138,761	140,174	-.6
Average sulfur Content(percent)	.8	.0	.3	-9.7
Gas (2002 cents per million Btu)	265.0	217.7	438.4	5.8
Average heat value (Btu per cubic foot)	1,029	1,029	1,020	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Nevada				
Sulfur Dioxide				
Coal	52	51	49	-0.6
Petroleum	1	*	*	-32.7
Gas	*	*	*	12.1
Total	53	51	49	-.9
Nitrogen Oxide				
Coal	62	39	39	-5.0
Petroleum	*	*	*	-26.9
Gas	3	8	7	9.2
Other	*	*	0	NM
Total	65	47	46	-3.8
Carbon Dioxide				
Coal	17,251	16,711	18,332	.7
Petroleum	283	34	24	-24.0
Gas	2,268	4,370	6,370	12.2
Total	19,801	21,115	24,726	2.5

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Nevada							
Retail Sales (thousand megawatthours)							
Residential	6,281	7,801	9,702	4.9	33.9	32.2	33.2
Commercial	4,298	5,454	7,538	6.4	23.2	22.5	25.8
Industrial	7,181	10,034	11,373	5.2	38.8	41.4	38.9
Other	740	930	592	-2.4	4.0	3.8	2.0
Total	18,499	24,219	29,204	5.2	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	455	543	915	8.1	37.6	38.9	37.2
Commercial	312	354	683	9.1	25.8	25.4	27.8
Industrial	403	462	824	8.3	33.3	33.1	33.5
Other	40	37	39	-.4	3.3	2.6	1.6
Total	1,211	1,395	2,460	8.2	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.25	6.95	9.43	3.0	NA	NA	NA
Commercial	7.26	6.49	9.06	2.5	NA	NA	NA
Industrial	5.62	4.61	7.25	2.9	NA	NA	NA
Other	5.42	3.94	6.54	2.1	NA	NA	NA
Total	6.54	5.76	8.42	2.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Nevada						
Number of Entities	1	14	0	5	0	20
Number of Retail Customers	650,358	317,383	0	12,762	0	980,503
Retail Sales (thousand megawatthours)	17,600	10,669	0	936	0	29,204
Percentage of Retail Sales	60.26	36.53	.00	3.20	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,570	850	0	41	0	2,460
Percentage of Revenue	63.81	34.53	.00	1.65	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	8.92	7.96	.00	4.34	0	8.42

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
New Hampshire		
NERC Region(s)		NPCC
Primary Energy Source		Nuclear
Net Summer Capability (megawatts)	3,427	43
Electric Utilities	1,105	43
Independent Power Producers & Combined Heat and Power	2,322	28
Net Generation (megawatthours)	15,953,078	43
Electric Utilities	12,276,456	37
Independent Power Producers & Combined Heat and Power	3,676,622	35
Emissions (thousand short tons)		
Sulfur Dioxide	44	39
Nitrogen Oxide	8	47
Carbon Dioxide	4,986	45
Sulfur Dioxide/sq. mile	5	20
Nitrogen Oxide/sq. mile	1	34
Carbon Dioxide/sq. mile	556	31
Utility and ESP Retail Electricity Sales (megawatthours)	10,490,029	44
Utility Retail Electricity Sales (megawatthours)	10,319,936	43
ESP Retail Electricity Sales (megawatthours)	170,093	18
Direct Use (megawatthours)	394,007	34
Average Retail Price (cents/kWh)	10.49	6

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
New Hampshire			
1. Seabrook	Nuclear	FPL Energy Seabrook LLC	1,161
2. Newington Power Facil	Nuclear	Newington Energy LLC	525
3. Merrimack	Petroleum, Coal	Public Service Co of NH	449
4. Newington	Gas, Petroleum	Public Service Co of NH	400
5. S C Moore	Hydro	U S Gen New England Inc	184
6. Comerford	Hydro	U S Gen New England Inc	162
7. Schiller	Gas, Petroleum, Coal	Public Service Co of NH	160
8. Berlin Gorham	Petroleum, Other, Hydro	Great Lakes Hydro America LLC	29
9. Pinetree Power Tamwor	Other	Pinetree Power Tamworth Inc	20
10. Amoskeag	Hydro	Public Service Co of NH	18

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
New Hampshire					
A. Public Service Company of NH	7,403,568	2,765,211	2,968,628	1,646,481	23,248
B. Granite State Electric Company	744,950	267,526	382,326	91,909	3,189
C. New Hampshire Elec Coop, Inc	657,703	395,880	208,253	52,050	1,520
D. Exeter & Hampton Electric Co	626,419	286,727	141,021	165,144	33,527
E. Concord Electric Company	554,265	171,070	160,345	152,668	70,182
Total	9,986,905	3,886,414	3,860,573	2,108,252	131,666
Percentage of Utility Sales	95	96	96	92	92

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Hampshire							
Coal	578	578	575	0.0	20.8	20.6	16.8
Petroleum	66	66	48	-3.5	2.4	2.3	1.4
Dual Fired	423	423	417	-.2	15.3	15.1	12.2
Nuclear	1,150	1,162	0	NM	41.5	41.4	.0
Hydroelectric	291	284	64	-15.5	10.5	10.1	1.9
Total Electric Utilities	**2,508**	**2,512**	**1,105**	**-8.7**	**90.5**	**89.6**	**32.2**
Petroleum	25	30	32	2.6	.9	1.1	.9
Natural Gas	0	0	543	NM	.0	.0	15.8
Dual Fired	5	7	7	4.1	.2	.2	.2
Nuclear	0	0	1,161	NM	.0	.0	33.9
Hydroelectric	89	88	449	19.7	3.2	3.1	13.1
Other Renewables	145	168	130	-1.1	5.2	6.0	3.8
Total IPP's & Combined Heat and Power	**264**	**292**	**2,322**	**27.3**	**9.5**	**10.4**	**67.8**
Coal	578	578	575	.0	20.8	20.6	16.8
Petroleum	92	96	80	-1.5	3.3	3.4	2.3
Natural Gas	0	0	543	NM	.0	.0	15.8
Dual Fired	428	430	424	-.1	15.4	15.3	12.4
Nuclear	1,150	1,162	1,161	.1	41.5	41.4	33.9
Hydroelectric	380	371	514	3.4	13.7	13.2	15.0
Other Renewables	145	168	130	-1.1	5.2	6.0	3.8
Total Electric Industry	**2,771**	**2,804**	**3,427**	**2.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Hampshire							
Coal	3,263,241	4,077,225	3,722,386	1.5	20.1	25.7	23.3
Petroleum	1,262,688	1,007,545	595,575	-8.0	7.8	6.3	3.7
Natural Gas	11,503	35,108	95,547	26.5	.1	.2	.6
Nuclear	9,046,805	7,979,448	7,599,861	-1.9	55.7	50.2	47.6
Hydroelectric	1,001,769	1,165,007	263,087	-13.8	6.2	7.3	1.6
Total Electric Utilities	**14,586,006**	**14,264,333**	**12,276,456**	**-1.9**	**89.8**	**89.8**	**77.0**
Petroleum	41,885	62,277	54,134	2.9	.3	.4	.3
Natural Gas	0	11,786	124,823	NM	.0	.1	.8
Nuclear	0	0	1,694,756	NM	.0	.0	10.6
Hydroelectric	408,841	456,584	877,853	8.9	2.5	2.9	5.5
Other Renewables	1,206,029	1,085,242	925,057	-2.9	7.4	6.8	5.8
Total IPP's & Combined Heat and Power	**1,656,754**	**1,615,889**	**3,676,622**	**9.3**	**10.2**	**10.2**	**23.0**
Coal	3,263,241	4,077,225	3,722,386	1.5	20.1	25.7	23.3
Petroleum	1,304,573	1,069,822	649,709	-7.5	8.0	6.7	4.1
Natural Gas	11,503	46,894	220,370	38.8	.1	.3	1.4
Nuclear	9,046,805	7,979,448	9,294,617	.3	55.7	50.2	58.3
Hydroelectric	1,410,610	1,621,591	1,140,940	-2.3	8.7	10.2	7.2
Other Renewables	1,206,029	1,085,242	925,057	-2.9	7.4	6.8	5.8
Total Electric Industry	**16,242,760**	**15,880,222**	**15,953,078**	**-.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New Hampshire				
Coal (2002 cents per million Btu)	179.3	167.8	180.3	0.1
Average heat value (Btu per pound)	13,179	13,054	13,017	-.1
Average sulfur Content(percent)	1.6	1.4	1.2	-3.6
Petroleum (2002 cents per million Btu)	204.8	270.9	370.5	6.8
Average heat value (Btu per gallon)	154,131	152,622	149,660	-.3
Average sulfur Content(percent)	1.7	1.3	1.5	-1.7
Gas (2002 cents per million Btu)	242.1	274.0	388.3	5.4
Average heat value (Btu per cubic foot)	1,016	1,017	1,031	.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New Hampshire				
Sulfur Dioxide				
Coal	40	49	39	-0.3
Petroleum	12	10	6	-7.9
Other	*	*	*	-6.8
Total	52	59	44	-1.7
Nitrogen Oxide				
Coal	20	18	6	-13.2
Petroleum	1	2	1	-2.6
Gas	*	*	*	35.7
Other	1	1	1	1.8
Total	23	21	8	-10.5
Carbon Dioxide				
Coal	3,600	4,528	4,141	1.6
Petroleum	1,306	1,040	691	-6.8
Gas	8	38	122	35.3
Other	31	32	32	.3
Total	4,945	5,639	4,986	.1

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Hampshire							
Retail Sales (thousand megawatthours)							
Residential	3,420	3,368	4,045	1.9	39.0	37.1	38.6
Commercial	2,123	3,248	4,014	7.3	24.2	35.8	38.3
Industrial	3,100	2,339	2,288	−3.3	35.4	25.8	21.8
Other	118	127	143	2.1	1.3	1.4	1.4
Total	8,761	9,081	10,490	2.0	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	469	473	476	.2	44.3	43.5	43.3
Commercial	260	379	405	5.0	24.6	34.8	36.8
Industrial	312	218	202	−4.7	29.5	20.0	18.4
Other	18	18	17	−.2	1.7	1.7	1.6
Total	1,059	1,088	1,100	.4	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	13.71	14.05	11.77	−1.7	NA	NA	NA
Commercial	12.27	11.66	10.09	−2.1	NA	NA	NA
Industrial	10.07	9.31	8.83	−1.4	NA	NA	NA
Other	14.81	14.45	12.07	−2.3	NA	NA	NA
Total	12.09	11.98	10.49	−1.6	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
New Hampshire						
Number of Entities	5	5	0	1	5	16
Number of Retail Customers	568,098	11,002	0	72,271	5,977	657,348
Retail Sales (thousand megawatthours)	9,487	175	0	658	170	10,490
Percentage of Retail Sales	90.44	1.67	.00	6.27	1.62	100.00
Revenue from Retail Sales (million 2002 dollars)	981	16	0	89	13	1,100
Percentage of Revenue	89.18	1.50	.00	8.13	1.19	100.00
Revenue per Kilowatthour (2002 cents/kWh)	10.34	9.42	.00	13.60	0	10.49

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
New Jersey		
NERC Region(s)		MACC
Primary Energy Source		Nuclear
Net Summer Capability (megawatts)	18,384	21
Electric Utilities	1,244	42
Independent Power Producers & Combined Heat and Power	17,140	6
Net Generation (megawatthours)	61,569,387	22
Electric Utilities	1,569,056	44
Independent Power Producers & Combined Heat and Power	60,000,331	6
Emissions (thousand short tons)		
Sulfur Dioxide	49	36
Nitrogen Oxide	41	36
Carbon Dioxide	22,339	37
Sulfur Dioxide/sq. mile	7	17
Nitrogen Oxide/sq. mile	5	7
Carbon Dioxide/sq. mile	3,011	9
Utility and ESP Retail Electricity Sales (megawatthours)	74,460,421	20
Utility Retail Electricity Sales (megawatthours)	73,368,045	20
ESP Retail Electricity Sales (megawatthours)	1,092,376	12
Direct Use (megawatthours)	14,141,784	4
Average Retail Price (cents/kWh)	9.31	10

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
New Jersey			
1. PSEG Salem Generating	Petroleum, Nuclear	PSEG Nuclear LLC	2,259
2. Bergen	Other, Gas	PSEG Fossil LLC	1,224
3. PSEG Hudson Generatin	Other, Petroleum, Gas	PSEG Fossil LLC	1,120
4. PSEG Hope Creek Gener	Nuclear	PSEG Nuclear LLC	1,049
5. Linden Cogen Plant	Petroleum, Other, Gas	Cogen Technologies Linden Vent	900
6. PSEG Burlington Gener	Other, Gas	PSEG Fossil LLC	802
7. AES Red Oak LLC	Gas	AES Red Oak LLC	792
8. PSEG Mercer Generatin	Other, Gas, Coal	PSEG Fossil LLC	777
9. PSEG Linden Generatin	Other, Petroleum, Gas	PSEG Fossil LLC	775
10. PSEG Kearny Generatin	Other, Petroleum, Gas	PSEG Fossil LLC	764

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
New Jersey					
A. Public Service Electric&Gas Co	41,555,465	12,825,350	21,664,674	6,684,529	380,912
B. Jersey Central Power&Light Co	20,562,264	8,972,974	8,462,157	3,045,994	81,139
C. Atlantic City Electric Company	8,583,371	4,103,761	3,693,045	739,644	46,921
D. Rockland Electric Company	1,542,342	696,176	776,409	62,972	6,785
E. City of Vineland	481,649	134,608	136,624	206,041	4,376
Total	72,725,091	26,732,869	34,732,909	10,739,180	520,133
Percentage of Utility Sales	98	98	97	97	90

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Jersey							
Coal	1,644	1,635	387	-14.8	10.0	9.7	2.1
Petroleum	3,072	2,788	286	-23.2	18.8	16.5	1.6
Natural Gas	2,863	1,984	0	NM	17.5	11.8	.0
Dual Fired	2,038	3,015	171	-24.1	12.4	17.9	.9
Nuclear	3,853	3,862	0	NM	23.5	22.9	.0
Hydroelectric	380	400	400	.6	2.3	2.4	2.2
Total Electric Utilities	**13,850**	**13,684**	**1,244**	**-23.5**	**84.6**	**81.2**	**6.8**
Coal	262	483	1,737	23.4	1.6	2.9	9.4
Petroleum	1	27	1,996	123.4	.0	.2	10.9
Natural Gas	315	574	3,293	29.8	1.9	3.4	17.9
Other Gases	0	0	21	NM	.0	.0	.1
Dual Fired	1,808	1,897	6,024	14.3	11.0	11.3	32.8
Nuclear	0	0	3,875	NM	.0	.0	21.1
Hydroelectric	13	13	13	.5	.1	.1	.1
Other Renewables	129	178	181	3.8	.8	1.1	1.0
Total IPP's & Combined Heat and Power	**2,528**	**3,171**	**17,140**	**23.7**	**15.4**	**18.8**	**93.2**
Coal	1,906	2,118	2,124	1.2	11.6	12.6	11.6
Petroleum	3,073	2,814	2,282	-3.3	18.8	16.7	12.4
Natural Gas	3,178	2,558	3,293	.4	19.4	15.2	17.9
Other Gases	0	0	21	NM	.0	.0	.1
Dual Fired	3,846	4,912	6,195	5.4	23.5	29.1	33.7
Nuclear	3,853	3,862	3,875	.1	23.5	22.9	21.1
Hydroelectric	393	413	413	.6	2.4	2.4	2.2
Other Renewables	129	178	181	3.8	.8	1.1	1.0
Total Electric Industry	**16,378**	**16,855**	**18,384**	**1.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Jersey							
Coal	5,465,762	6,821,610	1,416,711	-13.9	11.3	16.3	2.3
Petroleum	1,028,686	384,469	202,514	-16.5	2.1	.9	.3
Natural Gas	2,981,168	2,776,813	95,631	-31.8	6.2	6.7	.2
Nuclear	24,932,240	13,908,074	0	NM	51.6	33.3	.0
Hydroelectric	-123,234	-129,523	-145,800	NM	- .3	-.3	-.2
Total Electric Utilities	**34,284,622**	**23,761,443**	**1,569,056**	**-29.0**	**70.9**	**56.9**	**2.5**
Coal	9	2,076,596	8,188,343	360.5	.0	5.0	13.3
Petroleum	446,538	383,575	528,119	1.9	.9	.9	.9
Natural Gas	12,563,872	14,211,118	18,973,727	4.7	26.0	34.0	30.8
Other Gases	86,860	131,982	90,483	.5	.2	.3	.1
Nuclear	0	0	30,865,675	NM	.0	.0	50.1
Hydroelectric	19,005	18,371	12,030	-5.0	.0	.0	.0
Other Renewables	943,978	1,173,176	1,330,416	3.9	2.0	2.8	2.2
Other	0	0	11,538	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**14,060,261**	**17,994,817**	**60,000,331**	**17.5**	**29.1**	**43.1**	**97.5**
Coal	5,465,771	8,898,206	9,605,054	6.5	11.3	21.3	15.6
Petroleum	1,475,224	768,044	730,633	-7.5	3.1	1.8	1.2
Natural Gas	15,545,040	16,987,931	19,069,358	2.3	32.2	40.7	31.0
Other Gases	86,860	131,982	90,483	.5	.2	.3	.1
Nuclear	24,932,240	13,908,074	30,865,675	2.4	51.6	33.3	50.1
Hydroelectric	-104,229	-111,152	-133,770	NM	- .2	-.3	-.2
Other Renewables	943,978	1,173,176	1,330,416	3.9	2.0	2.8	2.2
Other	0	0	11,538	NM	.0	.0	.0
Total Electric Industry	**48,344,883**	**41,756,260**	**61,569,387**	**2.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New Jersey				
Coal (2002 cents per million Btu)	197.6	180.4	187.3	-0.6
Average heat value (Btu per pound)	13,397	13,084	12,853	-.5
Average sulfur Content(percent)	1.3	1.2	1.2	-.5
Petroleum (2002 cents per million Btu)	298.8	307.0	468.0	5.1
Average heat value (Btu per gallon)	149,284	148,489	141,631	-.6
Average sulfur Content(percent)	.4	.4	.4	*
Gas (2002 cents per million Btu)	256.3	303.3	404.4	5.2
Average heat value (Btu per cubic foot)	1,034	1,037	1,032	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New Jersey				
Sulfur Dioxide				
Coal	56	54	47	-2.1
Petroleum	7	3	2	-14.2
Gas	*	*	*	-13.7
Other	*	*	*	5.8
Total	64	57	49	-2.9
Nitrogen Oxide				
Coal	33	39	27	-2.1
Petroleum	2	*	1	-7.2
Gas	12	14	9	-3.8
Other	2	2	4	10.0
Total	48	57	41	-1.9
Carbon Dioxide				
Coal	5,834	9,798	10,499	6.8
Petroleum	1,378	596	830	-5.5
Gas	8,352	8,529	10,738	2.8
Other	143	203	272	7.4
Total	15,706	19,126	22,339	4.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Jersey							
Retail Sales (thousand megawatthours)							
Residential	22,042	22,286	27,183	2.4	33.6	33.8	36.5
Commercial	28,493	29,753	35,684	2.5	43.4	45.1	47.9
Industrial	14,596	13,369	11,016	-3.1	22.2	20.3	14.8
Other	490	507	578	1.9	.8	.8	.8
Total	65,621	65,915	74,460	1.4	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	2,801	2,768	2,821	.1	38.4	38.8	40.7
Commercial	3,090	3,165	3,166	.3	42.3	44.3	45.7
Industrial	1,315	1,114	862	-4.6	18.0	15.6	12.4
Other	96	96	81	-1.8	1.3	1.3	1.2
Total	7,301	7,142	6,930	-.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	12.71	12.42	10.38	-2.2	NA	NA	NA
Commercial	10.84	10.64	8.87	-2.2	NA	NA	NA
Industrial	9.01	8.33	7.83	-1.5	NA	NA	NA
Other	19.54	18.85	14.04	-3.6	NA	NA	NA
Total	11.13	10.83	9.31	-2.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
New Jersey						
Number of Entities	4	9	0	1	12	26
Number of Retail Customers	3,631,508	55,770	0	11,138	6,151	3,704,567
Retail Sales (thousand megawatthours)	72,243	988	0	137	1,092	74,460
Percentage of Retail Sales	97.02	1.33	.00	.18	1.47	100.00
Revenue from Retail Sales (million 2002 dollars)	6,763	101	0	15	51	6,930
Percentage of Revenue	97.59	1.46	.00	.22	.73	100.00
Revenue per Kilowatthour (2002 cents/kWh)	9.36	10.26	.00	10.91	0	9.31

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
New Mexico		
NERC Region(s)		SPP/WSCC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	5,936	38
Electric Utilities	5,463	32
Independent Power Producers & Combined Heat and Power	473	44
Net Generation (megawatthours)	30,661,707	40
Electric Utilities	29,926,241	34
Independent Power Producers & Combined Heat and Power	735,466	45
Emissions (thousand short tons)		
Sulfur Dioxide	51	33
Nitrogen Oxide	79	27
Carbon Dioxide	31,311	31
Sulfur Dioxide/sq. mile	0	43
Nitrogen Oxide/sq. mile	1	40
Carbon Dioxide/sq. mile	258	42
Utility and ESP Retail Electricity Sales (megawatthours)	19,206,917	39
Utility Retail Electricity Sales (megawatthours)	19,206,917	39
Direct Use (megawatthours)	501,942	29
Average Retail Price (cents/kWh)	6.73	21

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
New Mexico			
1. Four Corners	Gas, Coal	Arizona Public Service Co	2,040
2. San Juan	Petroleum, Coal	Public Service Co of NM	1,643
3. Cunningham	Gas	Southwestern Public Service Co	487
4. Escalante	Gas, Coal	Tri-State G & T Assn Inc	247
5. Rio Grande	Gas	El Paso Electric Co	238
6. Maddox	Gas	Southwestern Public Service Co	193
7. Reeves	Gas	Public Service Co of NM	154
8. Afton Generating Stat	Gas	Public Service Co of NM	151
9. Delta Person LLC	Petroleum, Gas	Delta Person LP	140
10. Milagro Cogeneration	Gas	Williams Field Services Co	122

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
New Mexico					
A. Public Service Company of NM	7,406,506	2,305,731	3,264,754	1,612,723	223,298
B. Southwestern Public Service Co	3,443,168	876,348	1,399,557	1,029,495	137,768
C. El Paso Electric Company	1,355,007	471,917	422,875	90,425	369,790
D. City of Farmington	1,043,320	210,101	336,012	485,454	11,753
E. Texas-New Mexico Power Company	1,018,335	237,072	232,135	530,720	18,408
Total	14,266,336	4,101,169	5,655,333	3,748,817	761,017
Percentage of Utility Sales	74	78	81	71	46

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Mexico							
Coal	3,901	3,901	3,942	0.1	74.4	72.0	66.4
Petroleum	24	23	15	−4.9	.4	.4	.3
Natural Gas	572	889	1,048	7.0	10.9	16.4	17.6
Dual Fired	507	311	377	−3.2	9.7	5.7	6.4
Hydroelectric	59	60	82	3.7	1.1	1.1	1.4
Total Electric Utilities	**5,062**	**5,183**	**5,463**	**.9**	**96.5**	**95.6**	**92.0**
Petroleum	43	24	10	−15.0	.8	.5	.2
Natural Gas	51	106	273	20.4	1.0	1.9	4.6
Dual Fired	87	105	184	8.6	1.7	1.9	3.1
Other Renewables	2	2	6	12.5	.0	.0	.1
Total IPP's & Combined Heat and Power	**183**	**237**	**473**	**11.1**	**3.5**	**4.4**	**8.0**
Coal	3,901	3,901	3,942	.1	74.4	72.0	66.4
Petroleum	66	47	25	−10.3	1.3	.9	.4
Natural Gas	623	994	1,321	8.7	11.9	18.3	22.3
Dual Fired	594	416	561	−.6	11.3	7.7	9.4
Hydroelectric	59	60	82	3.7	1.1	1.1	1.4
Other Renewables	2	2	6	12.5	.0	.0	.1
Total Electric Industry	**5,245**	**5,421**	**5,936**	**1.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Mexico							
Coal	25,507,029	27,078,660	26,902,880	0.6	88.7	86.1	87.7
Petroleum	35,337	21,075	30,710	−1.5	.1	.1	.1
Natural Gas	2,528,175	3,209,597	2,728,060	.8	8.8	10.2	8.9
Hydroelectric	293,827	258,810	264,591	−1.2	1.0	.8	.9
Total Electric Utilities	**28,364,368**	**30,568,142**	**29,926,241**	**.6**	**98.7**	**97.2**	**97.6**
Petroleum	7,953	1,923	2,379	−12.5	.0	.0	.0
Natural Gas	360,391	886,080	713,679	7.9	1.3	2.8	2.3
Other Renewables	11,816	6,212	19,408	5.7	.0	.0	.1
Total IPP's & Combined Heat and Power	**380,159**	**894,215**	**735,466**	**7.6**	**1.3**	**2.8**	**2.4**
Coal	25,507,029	27,078,660	26,902,880	.6	88.7	86.1	87.7
Petroleum	43,290	22,998	33,089	−2.9	.2	.1	.1
Natural Gas	2,888,566	4,095,677	3,441,739	2.0	10.0	13.0	11.2
Hydroelectric	293,827	258,810	264,591	−1.2	1.0	.8	.9
Other Renewables	11,816	6,212	19,408	5.7	.0	.0	.1
Total Electric Industry	**28,744,527**	**31,462,357**	**30,661,707**	**.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New Mexico				
Coal (2002 cents per million Btu)	152.5	137.3	152.9	*
Average heat value (Btu per pound)	8,991	9,069	9,286	0.3
Average sulfur Content(percent)	.8	.8	.7	−1.1
Petroleum (2002 cents per million Btu)	563.8	590.6	613.9	.9
Average heat value (Btu per gallon)	136,000	136,000	134,398	−.1
Average sulfur Content(percent)	.0	.0	.1	NM
Gas (2002 cents per million Btu)	244.4	266.3	303.8	2.4
Average heat value (Btu per cubic foot)	1,016	1,017	993	−.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New Mexico				
Sulfur Dioxide				
Coal	58	83	51	−1.4
Petroleum	*	*	*	−15.4
Gas	0	0	0	NM
Total	58	83	51	−1.4
Nitrogen Oxide				
Coal	114	80	76	−4.4
Petroleum	*	*	0	NM
Gas	3	4	3	.4
Other	*	*	*	3.7
Total	117	85	79	−4.3
Carbon Dioxide				
Coal	27,834	29,689	29,112	.5
Petroleum	39	21	27	−4.1
Gas	1,871	2,586	2,172	1.7
Total	29,745	32,296	31,311	.6

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New Mexico							
Retail Sales (thousand megawatthours)							
Residential	3,884	4,502	5,238	3.4	26.0	25.7	27.3
Commercial	4,759	5,440	7,000	4.4	31.9	31.0	36.4
Industrial	4,816	6,187	5,316	1.1	32.3	35.3	27.7
Other	1,467	1,399	1,653	1.3	9.8	8.0	8.6
Total	14,927	17,528	19,207	2.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	397	413	445	1.3	33.0	33.7	34.5
Commercial	444	443	505	1.5	36.9	36.1	39.1
Industrial	261	281	238	-1.0	21.7	22.9	18.4
Other	100	89	103	.3	8.3	7.2	8.0
Total	1,202	1,225	1,292	.8	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	10.23	9.17	8.50	-2.0	NA	NA	NA
Commercial	9.32	8.14	7.22	-2.8	NA	NA	NA
Industrial	5.42	4.54	4.48	-2.1	NA	NA	NA
Other	6.83	6.34	6.23	-1.0	NA	NA	NA
Total	8.05	6.99	6.73	-2.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
New Mexico						
Number of Entities	3	17	0	14	0	34
Number of Retail Customers	505,008	215,106	0	156,450	0	876,564
Retail Sales (thousand megawatthours)	9,780	6,529	0	2,898	0	19,207
Percentage of Retail Sales	50.92	33.99	.00	15.09	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	758	343	0	191	0	1,292
Percentage of Revenue	58.70	26.53	.00	14.77	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.75	5.25	.00	6.58	0	6.73

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
New York		
NERC Region(s)		NPCC
Primary Energy Source		Nuclear
Net Summer Capability (megawatts)	36,041	6
Electric Utilities	11,675	20
Independent Power Producers & Combined Heat and Power	24,366	5
Net Generation (megawatthours)	139,591,687	7
Electric Utilities	43,466,278	23
Independent Power Producers & Combined Heat and Power	96,125,409	5
Emissions (thousand short tons)		
Sulfur Dioxide	233	17
Nitrogen Oxide	89	24
Carbon Dioxide	56,695	15
Sulfur Dioxide/sq. mile	5	21
Nitrogen Oxide/sq. mile	2	24
Carbon Dioxide/sq. mile	1,201	23
Utility and ESP Retail Electricity Sales (megawatthours)	143,563,666	5
Utility Retail Electricity Sales (megawatthours)	123,931,972	6
ESP Retail Electricity Sales (megawatthours)	19,631,694	3
Direct Use (megawatthours)	6,916,359	5
Average Retail Price (cents/kWh)	11.29	4

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
New York			
1. Ravenswood	Petroleum, Gas	KeySpan-Ravenswood Inc	2,174
2. Robert Moses Niagara	Hydro	Power Authority of State of NY	2,160
3. Nine Mile Point Nucle	Nuclear	Nine Mile Point Nuclear Sta LLC	1,756
4. Oswego Harbor Power	Petroleum	NRG Oswego Harbor Power Operati	1,681
5. Northport	Gas, Petroleum	KeySpan Generation LLC	1,535
6. Astoria Generating St	Petroleum, Gas	Astoria Generating Co LP	1,293
7. Roseton Generating St	Gas, Petroleum	Dynegy Northeast Gen Inc	1,205
8. Bowline Point	Petroleum, Gas	Mirant New York Inc	1,139
9. Blenheim Gilboa	Hydro	Power Authority of State of NY	1,057
10. Indian Point 3	Nuclear	Entergy Nuclear Indian Point 3	984

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
New York					
A. Consolidated Edison Co-NY, Inc	31,754,647	12,510,162	18,594,627	468,108	181,750
B. Niagara Mohawk Power Corp	28,428,832	10,119,984	8,984,374	9,185,488	138,986
C. Long Island Power Authority	17,927,581	8,489,702	9,026,264	0	411,615
D. Power Authority of State of NY	14,271,883	0	120,574	4,805,037	9,346,272
E. New York State Elec & Gas Corp	12,466,903	5,544,411	2,918,363	2,891,026	1,113,103
Total	104,849,846	36,664,259	39,644,202	17,349,659	11,191,726
Percentage of Utility Sales	73	79	66	71	89

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New York							
Coal	3,879	3,880	302	-24.7	10.9	10.9	0.8
Petroleum	5,122	4,666	2,288	-8.6	14.4	13.1	6.3
Natural Gas	4,777	1,361	889	-17.0	13.4	3.8	2.5
Dual Fired	6,882	9,981	3,244	-8.0	19.3	28.1	9.0
Nuclear	4,831	4,961	498	-22.3	13.6	13.9	1.4
Hydroelectric	7,240	5,135	4,454	-5.3	20.3	14.4	12.4
Total Electric Utilities	**32,731**	**29,985**	**11,675**	**-10.8**	**91.9**	**84.3**	**32.4**
Coal	395	372	3,842	28.7	1.1	1.0	10.7
Petroleum	34	82	1,262	49.3	.1	.2	3.5
Natural Gas	445	2,186	2,363	20.4	1.2	6.1	6.6
Other Gases	20	23	0	NM	.1	.1	.0
Dual Fired	1,313	2,152	11,007	26.6	3.7	6.0	30.5
Nuclear	0	0	4,550	NM	.0	.0	12.6
Hydroelectric	305	359	952	13.5	.9	1.0	2.6
Other Renewables	353	417	390	1.1	1.0	1.2	1.1
Total IPP's & Combined Heat and Power	**2,866**	**5,592**	**24,366**	**26.8**	**8.1**	**15.7**	**67.6**
Coal	4,275	4,252	4,144	-.3	12.0	12.0	11.5
Petroleum	5,156	4,749	3,550	-4.1	14.5	13.3	9.8
Natural Gas	5,222	3,548	3,253	-5.1	14.7	10.0	9.0
Other Gases	20	23	0	NM	.1	.1	.0
Dual Fired	8,195	12,133	14,251	6.3	23.0	34.1	39.5
Nuclear	4,831	4,961	5,047	.5	13.6	13.9	14.0
Hydroelectric	7,545	5,494	5,406	-3.6	21.2	15.4	15.0
Other Renewables	353	417	390	1.1	1.0	1.2	1.1
Total Electric Industry	**35,597**	**35,576**	**36,041**	**.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New York							
Coal	21,819,763	21,752,103	1,682,022	-24.8	17.6	15.4	1.2
Petroleum	14,438,633	8,141,829	7,434,611	-7.1	11.6	5.8	5.3
Natural Gas	16,165,604	20,705,736	10,798,275	-4.4	13.0	14.7	7.7
Nuclear	26,889,261	29,569,618	3,826,848	-19.5	21.6	21.0	2.7
Hydroelectric	26,988,004	27,911,520	19,724,522	-3.4	21.7	19.8	14.1
Other Renewables	13,237	17,793	0	NM	.0	.0	.0
Total Electric Utilities	**106,314,502**	**108,098,599**	**43,466,278**	**-9.5**	**85.6**	**76.8**	**31.1**
Coal	2,682,203	2,306,691	21,557,090	26.1	2.2	1.6	15.4
Petroleum	634,333	446,547	4,099,499	23.0	.5	.3	2.9
Natural Gas	10,909,663	25,575,180	27,652,917	10.9	8.8	18.2	19.8
Other Gases	90,980	107,411	0	NM	.1	.1	.0
Nuclear	0	0	35,790,643	NM	.0	.0	25.6
Hydroelectric	1,319,590	1,613,322	4,402,149	14.3	1.1	1.1	3.2
Other Renewables	2,269,761	2,683,898	2,623,112	1.6	1.8	1.9	1.9
Total IPP's & Combined Heat and Power	**17,906,530**	**32,733,048**	**96,125,409**	**20.5**	**14.4**	**23.2**	**68.9**
Coal	24,501,966	24,058,794	23,239,112	-.6	19.7	17.1	16.6
Petroleum	15,072,966	8,588,376	11,534,110	-2.9	12.1	6.1	8.3
Natural Gas	27,075,267	46,280,916	38,451,192	4.0	21.8	32.9	27.5
Other Gases	90,980	107,411	0	NM	.1	.1	.0
Nuclear	26,889,261	29,569,618	39,617,491	4.4	21.6	21.0	28.4
Hydroelectric	28,307,594	29,524,842	24,126,671	-1.8	22.8	21.0	17.3
Other Renewables	2,282,998	2,701,691	2,623,112	1.6	1.8	1.9	1.9
Total Electric Industry	**124,221,032**	**140,831,647**	**139,591,687**	**1.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New York				
Coal (2002 cents per million Btu)	166.8	146.3	155.0	-0.8
Average heat value (Btu per pound)	12,914	13,105	12,825	-.1
Average sulfur Content(percent)	1.5	1.8	1.8	1.5
Petroleum (2002 cents per million Btu)	286.5	292.0	365.9	2.8
Average heat value (Btu per gallon)	151,012	150,326	148,476	-.2
Average sulfur Content(percent)	.8	.6	1.0	3.2
Gas (2002 cents per million Btu)	295.2	288.8	398.7	3.4
Average heat value (Btu per cubic foot)	1,031	1,026	1,019	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
New York				
Sulfur Dioxide				
Coal	236	266	186	-2.6
Petroleum	70	39	46	-4.6
Gas	*	*	*	6.0
Other	5	2	1	-19.7
Total	312	306	233	-3.2
Nitrogen Oxide				
Coal	83	61	50	-5.5
Petroleum	20	8	12	-5.1
Gas	28	34	22	-2.4
Other	6	5	5	-2.6
Total	137	109	89	-4.6
Carbon Dioxide				
Coal	26,039	25,821	24,305	-.8
Petroleum	13,365	7,768	10,634	-2.5
Gas	15,685	24,783	21,342	3.5
Other	321	381	413	2.8
Total	55,410	58,752	56,695	.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
New York							
Retail Sales (thousand megawatthours)							
Residential	39,897	40,059	46,234	1.6	30.6	30.4	32.2
Commercial	47,728	54,226	60,493	2.7	36.7	41.1	42.1
Industrial	30,187	25,282	24,290	-2.4	23.2	19.2	16.9
Other	12,357	12,369	12,547	.2	9.5	9.4	8.7
Total	130,170	131,936	143,564	1.1	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	5,855	5,813	6,278	.8	37.6	38.5	38.7
Commercial	6,198	6,759	7,540	2.2	39.9	44.8	46.5
Industrial	2,241	1,350	1,255	-6.2	14.4	8.9	7.7
Other	1,258	1,166	1,136	-1.1	8.1	7.7	7.0
Total	15,551	15,088	16,208	.5	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	14.67	14.51	13.58	-.9	NA	NA	NA
Commercial	12.99	12.46	12.46	-.4	NA	NA	NA
Industrial	7.42	5.34	5.16	-3.9	NA	NA	NA
Other	10.18	9.42	9.05	-1.3	NA	NA	NA
Total	11.95	11.44	11.29	-.6	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
New York						
Number of Entities	8	51	0	4	24	87
Number of Retail Customers	6,211,574	1,258,004	0	16,650	742,107	8,228,335
Retail Sales (thousand megawatthours)	85,815	37,945	0	173	19,632	143,564
Percentage of Retail Sales	59.77	26.43	.00	.12	13.67	100.00
Revenue from Retail Sales (million 2002 dollars)	11,229	3,493	0	15	1,471	16,208
Percentage of Revenue	69.28	21.55	.00	.09	9.08	100.00
Revenue per Kilowatthour (2002 cents/kWh)	13.09	9.21	.00	8.57	0	11.29

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
North Carolina		
NERC Region(s)		SERC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	26,674	11
Electric Utilities	23,652	7
Independent Power Producers & Combined Heat and Power	3,023	24
Net Generation (megawatthours)	124,468,030	11
Electric Utilities	115,597,653	5
Independent Power Producers & Combined Heat and Power	8,870,377	23
Emissions (thousand short tons)		
Sulfur Dioxide	483	9
Nitrogen Oxide	164	11
Carbon Dioxide	77,462	13
Sulfur Dioxide/sq. mile	10	10
Nitrogen Oxide/sq. mile	3	15
Carbon Dioxide/sq. mile	1,590	16
Utility and ESP Retail Electricity Sales (megawatthours)	122,686,468	9
Utility Retail Electricity Sales (megawatthours)	122,686,468	8
Direct Use (megawatthours)	3,080,472	13
Average Retail Price (cents/kWh)	6.74	20

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
North Carolina			
1. Roxboro	Petroleum, Coal	Carolina Power & Light Co	2,477
2. Belews Creek	Petroleum, Coal	Duke Energy Corp	2,240
3. McGuire	Nuclear	Duke Energy Corp	2,200
4. Marshall	Petroleum, Coal	Duke Energy Corp	2,090
5. Brunswick	Nuclear	Carolina Power & Light Co	1,631
6. Lincoln Combustion	Gas, Petroleum	Duke Energy Corp	1,267
7. Richmond	Petroleum, Gas	Carolina Power & Light Co	1,247
8. G G Allen	Petroleum, Coal	Duke Energy Corp	1,140
9. Asheville	Petroleum, Gas, Coal	Carolina Power & Light Co	937
10. Harris	Nuclear	Carolina Power & Light Co	900

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
North Carolina					
A. Duke Energy Corporation	53,983,683	18,808,288	19,207,782	15,742,821	224,792
B. Carolina Power & Light Company	35,327,404	13,332,731	10,777,990	9,873,037	1,343,646
C. Virginia Electric & Power Co	3,860,522	1,391,162	737,587	1,592,430	139,343
D. Fayetteville Public Works Comm	2,082,850	869,451	736,988	399,774	76,637
E. EnergyUnited Elec Member Corp	1,900,363	1,352,171	420,229	124,718	3,245
Total	97,154,822	35,753,803	31,880,576	27,732,780	1,787,663
Percentage of Utility Sales	79	72	81	88	82

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
North Carolina							
Coal	12,503	12,440	12,440	−0.1	58.5	54.5	46.6
Petroleum	304	355	400	3.1	1.4	1.6	1.5
Natural Gas	68	96	2,270	47.6	.3	.4	8.5
Dual Fired	718	1,851	2,176	13.1	3.4	8.1	8.2
Nuclear	4,639	4,749	4,731	.2	21.7	20.8	17.7
Hydroelectric	1,950	1,564	1,632	−2.0	9.1	6.8	6.1
Other Renewables	0	0	2	NM	.0	.0	.0
Total Electric Utilities	**20,182**	**21,054**	**23,652**	**1.8**	**94.5**	**92.2**	**88.7**
Coal	747	912	828	1.2	3.5	4.0	3.1
Petroleum	4	39	47	31.7	.0	.2	.2
Natural Gas	0	14	54	NM	.0	.1	.2
Dual Fired	185	195	1,415	25.4	.9	.9	5.3
Hydroelectric	9	364	376	50.6	.0	1.6	1.4
Other Renewables	194	221	266	3.6	.9	1.0	1.0
Other	37	37	37	.0	.2	.2	.1
Total IPP's & Combined Heat and Power	**1,176**	**1,783**	**3,023**	**11.1**	**5.5**	**7.8**	**11.3**
Coal	13,250	13,352	13,268	.0	62.0	58.5	49.7
Petroleum	307	394	447	4.2	1.4	1.7	1.7
Natural Gas	68	110	2,324	48.0	.3	.5	8.7
Dual Fired	903	2,046	3,591	16.6	4.2	9.0	13.5
Nuclear	4,639	4,749	4,731	.2	21.7	20.8	17.7
Hydroelectric	1,959	1,927	2,008	.3	9.2	8.4	7.5
Other Renewables	194	221	268	3.7	.9	1.0	1.0
Other	37	37	37	.0	.2	.2	.1
Total Electric Industry	**21,358**	**22,837**	**26,674**	**2.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
North Carolina							
Coal	59,383,147	70,181,392	71,223,313	2.0	62.3	60.8	57.2
Petroleum	165,175	211,974	376,170	9.6	.2	.2	.3
Natural Gas	239,530	376,599	1,935,684	26.1	.3	.3	1.6
Nuclear	23,758,927	32,453,074	39,626,849	5.8	24.9	28.1	31.8
Hydroelectric	5,206,835	4,148,053	2,435,637	-8.1	5.5	3.6	2.0
Total Electric Utilities	**88,753,614**	**107,371,092**	**115,597,653**	**3.0**	**93.1**	**93.0**	**92.9**
Coal	4,189,508	3,890,649	3,964,428	-.6	4.4	3.4	3.2
Petroleum	242,080	284,536	215,856	-1.3	.3	.2	.2
Natural Gas	155,221	323,338	1,625,187	29.8	.2	.3	1.3
Other Gases	0	0	863	NM	.0	.0	.0
Hydroelectric	26,538	1,731,636	1,081,586	51.0	.0	1.5	.9
Other Renewables	1,712,503	1,657,389	1,818,279	.7	1.8	1.4	1.5
Other	234,982	236,051	164,178	-3.9	.2	.2	.1
Total IPP's & Combined Heat and Power	**6,560,831**	**8,123,599**	**8,870,377**	**3.4**	**6.9**	**7.0**	**7.1**
Coal	63,572,655	74,072,041	75,187,741	1.9	66.7	64.1	60.4
Petroleum	407,255	496,510	592,026	4.2	.4	.4	.5
Natural Gas	394,751	699,937	3,560,871	27.7	.4	.6	2.9
Other Gases	0	0	863	NM	.0	.0	.0
Nuclear	23,758,927	32,453,074	39,626,849	5.8	24.9	28.1	31.8
Hydroelectric	5,233,373	5,879,689	3,517,223	-4.3	5.5	5.1	2.8
Other Renewables	1,712,503	1,657,389	1,818,279	.7	1.8	1.4	1.5
Other	234,982	236,051	164,178	-3.9	.2	.2	.1
Total Electric Industry	**95,314,445**	**115,494,691**	**124,468,030**	**3.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
North Carolina				
Coal (2002 cents per million Btu)	189.4	146.9	176.1	-0.8
Average heat value (Btu per pound)	12,465	12,368	12,342	-.1
Average sulfur Content(percent)	1.0	.9	.8	-1.3
Petroleum (2002 cents per million Btu)	451.5	439.6	466.5	.4
Average heat value (Btu per gallon)	138,611	138,266	145,562	.5
Average sulfur Content(percent)	.0	.0	1.0	NM
Gas (2002 cents per million Btu)	392.0	319.3	343.9	-1.4
Average heat value (Btu per cubic foot)	1,033	1,037	1,010	-.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
North Carolina				
Sulfur Dioxide				
Coal	450	528	476	0.6
Petroleum	*	5	3	25.1
Gas	0	0	0	NM
Other	4	6	4	.4
Total	454	539	483	.7
Nitrogen Oxide				
Coal	226	297	160	-3.7
Petroleum	1	1	*	-2.8
Gas	1	1	2	10.8
Other	1	2	2	4.5
Total	228	300	164	-3.6
Carbon Dioxide				
Coal	63,236	73,032	75,349	2.0
Petroleum	447	617	590	3.1
Gas	274	488	1,508	20.9
Other	16	15	14	-1.1
Total	63,972	74,153	77,462	2.1

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
North Carolina							
Retail Sales (thousand megawatthours)							
Residential	37,742	40,611	49,854	3.1	37.8	37.2	40.6
Commercial	26,747	31,388	39,277	4.4	26.8	28.8	32.0
Industrial	33,488	35,095	31,381	-.7	33.6	32.2	25.6
Other	1,800	1,955	2,174	2.1	1.8	1.8	1.8
Total	99,778	109,050	122,686	2.3	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	3,438	3,353	4,085	1.9	46.6	46.2	49.4
Commercial	1,965	2,074	2,559	3.0	26.6	28.6	31.0
Industrial	1,829	1,700	1,474	-2.4	24.8	23.4	17.8
Other	142	136	146	.3	1.9	1.9	1.8
Total	7,373	7,264	8,263	1.3	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	9.11	8.26	8.19	-1.2	NA	NA	NA
Commercial	7.35	6.61	6.51	-1.3	NA	NA	NA
Industrial	5.46	4.84	4.70	-1.7	NA	NA	NA
Other	7.87	6.97	6.70	-1.8	NA	NA	NA
Total	7.39	6.66	6.74	-1.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
North Carolina						
Number of Entities	3	76	0	29	0	108
Number of Retail Customers	2,906,685	568,343	0	840,761	0	4,315,789
Retail Sales (thousand megawatthours)	93,172	15,331	0	14,184	0	122,686
Percentage of Retail Sales	75.94	12.50	.00	11.56	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	5,865	1,213	0	1,185	0	8,263
Percentage of Revenue	70.97	14.68	.00	14.35	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.29	7.91	.00	8.36	0	6.74

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
North Dakota		
NERC Region(s)		MAPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	4,699	41
Electric Utilities	4,659	35
Independent Power Producers & Combined Heat and Power	40	49
Net Generation (megawatthours)	31,306,312	39
Electric Utilities	31,147,221	32
Independent Power Producers & Combined Heat and Power	159,091	49
Emissions (thousand short tons)		
Sulfur Dioxide	144	23
Nitrogen Oxide	77	29
Carbon Dioxide	36,416	29
Sulfur Dioxide/sq. mile	2	30
Nitrogen Oxide/sq. mile	1	32
Carbon Dioxide/sq. mile	528	34
Utility and ESP Retail Electricity Sales (megawatthours)	10,219,353	45
Utility Retail Electricity Sales (megawatthours)	10,219,353	44
Direct Use (megawatthours)	191,751	37
Average Retail Price (cents/kWh)	5.45	46

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
North Dakota			
1. Coal Creek	Petroleum, Coal	Great River Energy	1,091
2. Antelope Valley	Petroleum, Coal	Basin Electric Power Coop	904
3. Milton R Young	Petroleum, Coal	Minnkota Power Coop Inc	705
4. Leland Olds	Petroleum, Coal	Basin Electric Power Coop	669
5. Garrison	Hydro	USCE-Missouri River District	497
6. Coyote	Petroleum, Coal	Otter Tail Power Co	427
7. Stanton	Petroleum, Coal	Great River Energy	187
8. R M Heskett	Gas, Coal	MDU Resources Group Inc	102
9. Jamestown	Petroleum	Otter Tail Power Co	42
10. American Crystal Suga	Coal	American Crystal Sugar Co	13

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
North Dakota					
A. Northern States Power Company	2,047,352	737,573	965,437	319,618	24,724
B. Otter Tail Power Company	1,478,095	523,700	871,225	53,519	29,651
C. MDU Resources Group, Inc	1,333,091	512,592	630,043	130,710	59,746
D. Basin Electric Power Coop	917,718	0	0	917,718	0
E. Cass County Electric Coop, Inc	683,399	389,301	224,853	60,469	8,776
Total	6,459,655	2,163,166	2,691,558	1,482,034	122,897
Percentage of Utility Sales	63	59	79	56	24

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
North Dakota							
Coal	3,856	4,062	4,084	0.6	85.6	85.2	86.9
Petroleum	66	117	69	.5	1.5	2.5	1.5
Natural Gas	10	9	10	-.5	.2	.2	.2
Hydroelectric	545	545	497	-1.0	12.1	11.4	10.6
Total Electric Utilities	4,478	4,733	4,659	.4	99.4	99.3	99.2
Coal	18	18	21	1.9	.4	.4	.5
Natural Gas	3	0	0	NM	.1	.0	.0
Other Gases	7	7	8	1.7	.2	.2	.2
Other Renewables	0	9	10	NM	.0	.2	.2
Total IPP's & Combined Heat and Power	29	35	40	3.8	.6	.7	.8
Coal	3,874	4,080	4,105	.6	86.0	85.6	87.3
Petroleum	66	117	69	.5	1.5	2.5	1.5
Natural Gas	13	9	10	-3.6	.3	.2	.2
Other Gases	7	7	8	1.7	.2	.2	.2
Hydroelectric	545	545	497	-1.0	12.1	11.4	10.6
Other Renewables	0	9	10	NM	.0	.2	.2
Total Electric Industry	4,506	4,767	4,699	.5	100.0	100.0	100.0

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
North Dakota							
Coal	27,048,924	26,314,471	29,518,865	1.0	94.4	88.1	94.3
Petroleum	35,795	85,698	35,728	.0	.1	.3	.1
Natural Gas	-5	18	12	NM	.0	.0	.0
Hydroelectric	1,415,110	3,319,577	1,592,616	1.3	4.9	11.1	5.1
Total Electric Utilities	28,499,824	29,719,764	31,147,221	1.0	99.4	99.6	99.5
Coal	91,789	75,481	92,659	.1	.3	.3	.3
Petroleum	25,323	8,529	2,848	-21.6	.1	.0	.0
Natural Gas	7,082	373	8,030	1.4	.0	.0	.0
Other Gases	39,393	44,317	55,144	3.8	.1	.1	.2
Other Renewables	0	4,139	410	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	163,587	132,838	159,091	-.3	.6	.4	.5
Coal	27,140,713	26,389,952	29,611,524	1.0	94.7	88.4	94.6
Petroleum	61,118	94,227	38,576	-5.0	.2	.3	.1
Natural Gas	7,077	391	8,042	1.4	.0	.0	.0
Other Gases	39,393	44,317	55,144	3.8	.1	.1	.2
Hydroelectric	1,415,110	3,319,577	1,592,616	1.3	4.9	11.1	5.1
Other Renewables	0	4,139	410	NM	.0	.0	.0
Total Electric Industry	28,663,411	29,852,602	31,306,312	1.0	100.0	100.0	100.0

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
North Dakota				
Coal (2002 cents per million Btu)	79.6	80.0	74.3	-0.8
Average heat value (Btu per pound)	6,570	6,559	6,523	-.1
Average sulfur Content(percent)	.7	.8	.7	-.2
Petroleum (2002 cents per million Btu)	492.3	471.9	572.8	1.7
Average heat value (Btu per gallon)	138,018	139,091	141,343	.3
Average sulfur Content(percent)	.0	.0	.4	NM
Gas (2002 cents per million Btu)	473.7	330.9	247.9	-6.9
Average heat value (Btu per cubic foot)	1,080	1,066	950	-1.4

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
North Dakota				
Sulfur Dioxide				
Coal	144	178	144	0.0
Petroleum	*	*	*	-23.1
Total	144	178	144	*
Nitrogen Oxide				
Coal	109	94	77	-3.8
Petroleum	*	*	*	-23.6
Gas	*	*	*	3.7
Other	0	0	0	NM
Total	110	94	77	-3.8
Carbon Dioxide				
Coal	33,383	32,482	36,322	.9
Petroleum	57	81	35	-5.3
Gas	38	41	59	5.1
Total	33,478	32,605	36,416	.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
North Dakota							
Retail Sales (thousand megawatthours)							
Residential	3,209	3,437	3,664	1.5	43.2	41.5	35.8
Commercial	1,831	2,300	3,404	7.1	24.6	27.8	33.3
Industrial	1,905	2,076	2,636	3.7	25.6	25.1	25.8
Other	487	469	516	.6	6.6	5.7	5.0
Total	7,432	8,282	10,219	3.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	226	222	234	.4	46.8	46.1	42.0
Commercial	132	145	199	4.7	27.4	30.2	35.8
Industrial	103	93	105	.2	21.3	19.4	18.8
Other	22	21	19	-1.4	4.5	4.3	3.4
Total	482	481	557	1.6	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.03	6.45	6.39	-1.1	NA	NA	NA
Commercial	7.22	6.32	5.85	-2.3	NA	NA	NA
Industrial	5.40	4.50	3.98	-3.3	NA	NA	NA
Other	4.44	4.39	3.68	-2.0	NA	NA	NA
Total	6.49	5.81	5.45	-1.9	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
North Dakota						
Number of Entities	0	21	0	18	0	39
Number of Retail Customers	0	229,979	0	120,067	0	350,046
Retail Sales (thousand megawatthours)	0	5,607	0	4,612	0	10,219
Percentage of Retail Sales	.00	54.87	.00	45.13	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	0	313	0	244	0	557
Percentage of Revenue	.00	56.19	.00	43.81	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	.00	5.58	.00	5.29	0	5.45

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Ohio		
NERC Region(s)		ECAR
Primary Energy Source		Coal
Net Summer Capability (megawatts)	31,477	8
Electric Utilities	27,885	3
Independent Power Producers & Combined Heat and Power	3,592	21
Net Generation (megawatthours)	147,068,850	6
Electric Utilities	139,904,106	3
Independent Power Producers & Combined Heat and Power	7,164,744	27
Emissions (thousand short tons)		
Sulfur Dioxide	1,172	1
Nitrogen Oxide	385	1
Carbon Dioxide	135,181	2
Sulfur Dioxide/sq. mile	29	1
Nitrogen Oxide/sq. mile	9	5
Carbon Dioxide/sq. mile	3,301	5
Utility and ESP Retail Electricity Sales (megawatthours)	155,999,230	4
Utility Retail Electricity Sales (megawatthours)	135,562,777	4
ESP Retail Electricity Sales (megawatthours)	20,436,453	2
Direct Use (megawatthours)	643,168	27
Average Retail Price (cents/kWh)	6.66	22

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Ohio			
1. General James M Gavin	Petroleum, Coal	Ohio Power Co	2,600
2. J M Stuart	Petroleum, Coal	Dayton Power & Light Co	2,350
3. W H Sammis	Petroleum, Coal	Ohio Edison Co	2,233
4. Conesville	Petroleum, Coal	Columbus Southern Power Co	1,925
5. Cardinal	Petroleum, Coal	Cardinal Operating Co	1,800
6. Muskingum River	Petroleum, Coal	Ohio Power Co	1,365
7. Walter C Beckjord	Petroleum, Coal	Cincinnati Gas & Electric Co	1,304
8. W H Zimmer	Petroleum, Coal	Cincinnati Gas & Electric Co	1,300
9. Miami Fort	Petroleum, Coal	Cincinnati Gas & Electric Co	1,300
10. Eastlake	Petroleum, Coal	Cleveland Electric Illuminating	1,257

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Ohio					
A. Ohio Power Company	27,445,018	7,219,163	5,487,285	14,653,312	85,258
B. Ohio Edison Company	18,685,328	7,071,013	4,830,925	6,635,794	147,596
C. Cincinnati Gas & Electric Co	18,463,484	7,204,119	4,714,911	5,116,622	1,427,832
D. Columbus Southern Power Co	17,488,494	7,009,459	7,150,771	2,852,329	475,935
E. Dayton Power & Light Company	13,822,904	5,301,821	3,526,242	3,593,676	1,401,165
Total	95,905,228	33,805,575	25,710,134	32,851,733	3,537,786
Percentage of Utility Sales	61	67	63	54	90

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Ohio							
Coal	23,043	22,415	21,599	-0.7	83.7	83.2	68.6
Petroleum	870	752	947	1.0	3.2	2.8	3.0
Natural Gas	502	512	1,834	15.5	1.8	1.9	5.8
Dual Fired	516	695	1,140	9.2	1.9	2.6	3.6
Nuclear	2,042	2,042	2,111	.4	7.4	7.6	6.7
Hydroelectric	124	123	164	3.2	.4	.5	.5
Other Renewables	90	90	90	.0	.3	.3	.3
Total Electric Utilities	**27,186**	**26,630**	**27,885**	**.3**	**98.8**	**98.8**	**88.6**
Coal	193	198	1,099	21.3	.7	.7	3.5
Petroleum	8	6	49	22.9	.0	.0	.2
Natural Gas	2	1	810	101.0	.0	.0	2.6
Other Gases	63	63	81	2.8	.2	.2	.3
Dual Fired	35	17	1,535	52.1	.1	.1	4.9
Hydroelectric	3	0	0	NM	.0	.0	.0
Other Renewables	29	37	17	-5.5	.1	.1	.1
Total IPP's & Combined Heat and Power	**333**	**322**	**3,592**	**30.3**	**1.2**	**1.2**	**11.4**
Coal	23,235	22,613	22,698	-.3	84.4	83.9	72.1
Petroleum	877	758	996	1.4	3.2	2.8	3.2
Natural Gas	503	514	2,644	20.2	1.8	1.9	8.4
Other Gases	63	63	81	2.8	.2	.2	.3
Dual Fired	551	712	2,675	19.2	2.0	2.6	8.5
Nuclear	2,042	2,042	2,111	.4	7.4	7.6	6.7
Hydroelectric	127	123	164	2.9	.5	.5	.5
Other Renewables	119	127	107	-1.1	.4	.5	.3
Total Electric Industry	**27,518**	**26,951**	**31,477**	**1.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Ohio							
Coal	123,024,655	124,909,642	127,373,404	0.4	91.0	87.5	86.6
Petroleum	276,037	272,780	380,710	3.6	.2	.2	.3
Natural Gas	176,872	228,254	796,761	18.2	.1	.2	.5
Nuclear	10,010,661	15,330,830	10,864,902	.9	7.4	10.7	7.4
Hydroelectric	183,069	507,368	488,329	11.5	.1	.4	.3
Other Renewables	64,134	0	0	NM	.0	.0	.0
Total Electric Utilities	**133,735,428**	**141,248,874**	**139,904,106**	**.5**	**98.9**	**98.9**	**95.1**
Coal	771,257	525,777	5,579,662	24.6	.6	.4	3.8
Petroleum	69,965	21,128	8,409	−21.0	.1	.0	.0
Natural Gas	194,579	240,680	969,893	19.5	.1	.2	.7
Other Gases	128,520	189,767	206,565	5.4	.1	.1	.1
Hydroelectric	6,544	0	0	NM	.0	.0	.0
Other Renewables	330,998	585,021	151,310	−8.3	.2	.4	.1
Other	0	0	248,904	NM	.0	.0	.2
Total IPP's & Combined Heat and Power	**1,501,863**	**1,562,373**	**7,164,744**	**19.0**	**1.1**	**1.1**	**4.9**
Coal	123,795,912	125,435,419	132,953,066	.8	91.5	87.8	90.4
Petroleum	346,002	293,908	389,119	1.3	.3	.2	.3
Natural Gas	371,451	468,934	1,766,654	18.9	.3	.3	1.2
Other Gases	128,520	189,767	206,565	5.4	.1	.1	.1
Nuclear	10,010,661	15,330,830	10,864,902	.9	7.4	10.7	7.4
Hydroelectric	189,613	507,368	488,329	11.1	.1	.4	.3
Other Renewables	395,132	585,021	151,310	−10.1	.3	.4	.1
Other	0	0	248,904	NM	.0	.0	.2
Total Electric Industry	**135,237,291**	**142,811,247**	**147,068,850**	**.9**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Ohio				
Coal (2002 cents per million Btu)	157.5	135.7	122.6	−2.7
Average heat value (Btu per pound)	12,049	11,891	11,644	−.4
Average sulfur Content(percent)	2.4	2.0	2.0	−2.1
Petroleum (2002 cents per million Btu)	208.7	437.5	532.4	11.0
Average heat value (Btu per gallon)	81,276	135,936	138,681	6.1
Average sulfur Content(percent)	3.7	3.5	.1	−31.0
Gas (2002 cents per million Btu)	318.4	373.0	374.7	1.8
Average heat value (Btu per cubic foot)	1,030	1,024	1,026	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Ohio				
Sulfur Dioxide				
Coal	2,140	1,476	1,160	–6.6
Petroleum	1	*	12	36.0
Gas	0	0	*	NM
Other	1	1	1	–3.8
Total	2,141	1,478	1,172	–6.5
Nitrogen Oxide				
Coal	531	547	377	–3.7
Petroleum	*	*	1	17.1
Gas	4	4	6	4.0
Other	1	*	1	–10.2
Total	537	551	385	–3.6
Carbon Dioxide				
Coal	126,083	127,966	133,406	.6
Petroleum	344	291	293	–1.8
Gas	356	492	1,481	17.2
Other	9	0	0	NM
Total	126,792	128,748	135,181	.7

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Ohio							
Retail Sales (thousand megawatthours)							
Residential	41,950	43,635	50,612	2.1	28.2	27.5	32.4
Commercial	33,299	36,373	40,593	2.2	22.4	22.9	26.0
Industrial	68,831	73,888	60,855	–1.4	46.3	46.6	39.0
Other	4,491	4,612	3,940	–1.4	3.0	2.9	2.5
Total	148,571	158,508	155,999	.5	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	3,907	3,869	4,193	.8	38.0	38.0	40.4
Commercial	2,816	2,866	3,119	1.1	27.4	28.1	30.0
Industrial	3,258	3,161	2,845	–1.5	31.6	31.0	27.4
Other	312	290	225	–3.6	3.0	2.8	2.2
Total	10,293	10,185	10,383	.1	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	9.31	8.87	8.29	–1.3	NA	NA	NA
Commercial	8.46	7.88	7.68	–1.1	NA	NA	NA
Industrial	4.73	4.28	4.68	–.1	NA	NA	NA
Other	6.94	6.29	5.70	–2.2	NA	NA	NA
Total	6.93	6.43	6.66	–.4	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Ohio						
Number of Entities	9	87	0	23	12	131
Number of Retail Customers	3,888,071	377,409	0	341,086	779,046	5,385,612
Retail Sales (thousand megawatthours)	119,112	9,690	0	6,761	20,436	155,999
Percentage of Retail Sales	76.35	6.21	.00	4.33	13.10	100.00
Revenue from Retail Sales (million 2002 dollars)	8,533	665	0	457	728	10,383
Percentage of Revenue	82.18	6.41	.00	4.40	7.01	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.16	6.87	.00	6.76	0	6.66

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Oklahoma		
NERC Region(s)		SPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	16,232	22
Electric Utilities	13,387	18
Independent Power Producers & Combined Heat and Power	2,845	27
Net Generation (megawatthours)	59,183,419	23
Electric Utilities	51,218,320	20
Independent Power Producers & Combined Heat and Power	7,965,099	24
Emissions (thousand short tons)		
Sulfur Dioxide	166	21
Nitrogen Oxide	98	18
Carbon Dioxide	52,549	18
Sulfur Dioxide/sq. mile	2	27
Nitrogen Oxide/sq. mile	1	27
Carbon Dioxide/sq. mile	765	28
Utility and ESP Retail Electricity Sales (megawatthours)	49,485,466	26
Utility Retail Electricity Sales (megawatthours)	49,485,466	25
Direct Use (megawatthours)	1,175,727	24
Average Retail Price (cents/kWh)	5.59	43

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Oklahoma			
1. Muskogee	Gas, Coal	Oklahoma Gas & Electric Co	1,666
2. Northeastern	Gas, Coal	Public Service Co of Oklahoma	1,549
3. Seminole	Gas	Oklahoma Gas & Electric Co	1,536
4. Sooner	Petroleum, Coal	Oklahoma Gas & Electric Co	1,019
5. GRDA	Petroleum, Gas, Coal	Grand River Dam Authority	1,010
6. Riverside	Gas	Public Service Co of Oklahoma	920
7. Horseshoe Lake	Petroleum, Gas	Oklahoma Gas & Electric Co	860
8. Green Country Energy	Gas	Green Country OP Services LLC	779
9. Oneta Energy Center	Gas	Calpine Central, L.P.	560
10. Mustang	Gas	Oklahoma Gas & Electric Co	533

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Oklahoma					
A. Oklahoma Gas & Electric Co	20,544,045	7,358,370	5,072,247	5,567,976	2,545,452
B. Public Service Co of Oklahoma	16,466,566	5,755,212	5,034,503	4,840,879	835,972
C. Oklahoma Electric Coop, Inc	770,609	529,787	200,387	39,865	570
D. Edmond Electric Department	679,268	378,387	75,311	141,348	84,222
E. Grand River Dam Authority	535,801	0	40,538	495,263	0
Total	38,996,289	14,021,756	10,422,986	11,085,331	3,466,216
Percentage of Utility Sales	79	70	80	86	97

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Oklahoma							
Coal	4,874	4,848	4,896	0.0	35.7	35.4	30.2
Petroleum	30	28	34	1.3	.2	.2	.2
Natural Gas	849	961	5,490	23.0	6.2	7.0	33.8
Other Gases	52	52	61	1.8	.4	.4	.4
Dual Fired	6,045	6,006	1,850	−12.3	44.3	43.8	11.4
Hydroelectric	1,009	1,035	1,056	.5	7.4	7.6	6.5
Total Electric Utilities	**12,859**	**12,931**	**13,387**	**.4**	**94.2**	**94.4**	**82.5**
Coal	434	434	391	−1.2	3.2	3.2	2.4
Petroleum	0	0	2	NM	.0	.0	.0
Natural Gas	245	235	2,350	28.6	1.8	1.7	14.5
Other Gases	17	17	17	−.1	.1	.1	.1
Dual Fired	13	9	10	−2.7	.1	.1	.1
Other Renewables	76	76	76	.0	.6	.6	.5
Total IPP's & Combined Heat and Power	**785**	**772**	**2,845**	**15.4**	**5.8**	**5.6**	**17.5**
Coal	5,308	5,282	5,287	.0	38.9	38.5	32.6
Petroleum	30	28	36	1.9	.2	.2	.2
Natural Gas	1,094	1,196	7,840	24.5	8.0	8.7	48.3
Other Gases	69	69	78	1.3	.5	.5	.5
Dual Fired	6,057	6,016	1,860	−12.3	44.4	43.9	11.5
Hydroelectric	1,009	1,035	1,056	.5	7.4	7.6	6.5
Other Renewables	76	76	76	.0	.6	.6	.5
Total Electric Industry	**13,644**	**13,702**	**16,232**	**1.9**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Oklahoma							
Coal	28,990,113	33,036,688	33,444,114	1.6	54.5	62.5	56.5
Petroleum	14,027	12,568	10,311	−3.4	.0	.0	.0
Natural Gas	15,510,168	12,506,748	15,953,919	.3	29.2	23.7	27.0
Hydroelectric	4,296,412	2,824,098	1,809,976	−9.2	8.1	5.3	3.1
Total Electric Utilities	**48,810,720**	**48,380,102**	**51,218,320**	**.5**	**91.8**	**91.5**	**86.5**
Coal	2,702,062	2,996,140	2,520,664	−.8	5.1	5.7	4.3
Petroleum	42,292	14,224	39,560	−.7	.1	.0	.1
Natural Gas	1,252,398	1,175,582	5,095,120	16.9	2.4	2.2	8.6
Other Gases	89,656	66,790	70,710	−2.6	.2	.1	.1
Other Renewables	262,544	231,139	239,045	−1.0	.5	.4	.4
Total IPP's & Combined Heat and Power	**4,348,952**	**4,483,875**	**7,965,099**	**7.0**	**8.2**	**8.5**	**13.5**
Coal	31,692,175	36,032,828	35,964,778	1.4	59.6	68.2	60.8
Petroleum	56,319	26,792	49,871	−1.3	.1	.1	.1
Natural Gas	16,762,566	13,682,330	21,049,039	2.6	31.5	25.9	35.6
Other Gases	89,656	66,790	70,710	−2.6	.2	.1	.1
Hydroelectric	4,296,412	2,824,098	1,809,976	−9.2	8.1	5.3	3.1
Other Renewables	262,544	231,139	239,045	−1.0	.5	.4	.4
Total Electric Industry	**53,159,672**	**52,863,977**	**59,183,419**	**1.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Oklahoma				
Coal (2002 cents per million Btu)	137.8	94.4	95.9	–3.9
Average heat value (Btu per pound)	8,621	8,641	8,821	.3
Average sulfur Content(percent)	.4	.3	.4	.5
Petroleum (2002 cents per million Btu)	389.9	420.6	483.8	2.4
Average heat value (Btu per gallon)	138,837	140,096	147,024	.6
Average sulfur Content(percent)	.0	.0	*	NM
Gas (2002 cents per million Btu)	346.4	295.8	344.1	–.1
Average heat value (Btu per cubic foot)	1,039	1,032	1,025	–.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Oklahoma				
Sulfur Dioxide				
Coal	116	120	165	4.0
Petroleum	*	*	*	21.1
Gas	0	0	*	NM
Other	*	*	1	3.4
Total	117	121	166	4.0
Nitrogen Oxide				
Coal	130	84	76	–5.7
Petroleum	*	*	*	.4
Gas	20	18	22	1.4
Other	*	*	*	2.8
Total	149	102	98	–4.5
Carbon Dioxide				
Coal	35,143	39,897	40,424	1.6
Petroleum	46	26	44	–.4
Gas	9,916	8,460	12,080	2.2
Other	0	*	0	NM
Total	45,105	48,383	52,549	1.7

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Oklahoma							
Retail Sales (thousand megawatthours)							
Residential	15,901	17,376	19,927	2.5	39.2	39.1	40.3
Commercial	10,824	11,754	13,097	2.1	26.7	26.4	26.5
Industrial	11,699	12,802	12,898	1.1	28.9	28.8	26.1
Other	2,107	2,521	3,564	6.0	5.2	5.7	7.2
Total	40,531	44,453	49,485	2.2	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,265	1,184	1,341	.6	47.0	47.8	48.5
Commercial	748	692	753	.1	27.8	27.9	27.2
Industrial	539	478	491	−1.0	20.0	19.3	17.8
Other	138	123	180	3.0	5.1	5.0	6.5
Total	2,691	2,476	2,765	.3	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.96	6.81	6.73	−1.8	NA	NA	NA
Commercial	6.91	5.88	5.75	−2.0	NA	NA	NA
Industrial	4.61	3.73	3.81	−2.1	NA	NA	NA
Other	6.54	4.89	5.06	−2.8	NA	NA	NA
Total	6.64	5.57	5.59	−1.9	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Oklahoma						
Number of Entities	1	72	0	24	0	97
Number of Retail Customers	503,683	887,728	0	390,986	0	1,782,397
Retail Sales (thousand megawatthours)	16,467	25,973	0	7,046	0	49,485
Percentage of Retail Sales	33.28	52.49	.00	14.24	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	736	1,530	0	499	0	2,765
Percentage of Revenue	26.61	55.36	.00	18.03	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	4.47	5.89	.00	7.08	0	5.59

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Oregon		
NERC Region(s)		WSCC
Primary Energy Source		Hydro
Net Summer Capability (megawatts)	12,485	26
Electric Utilities	10,348	21
Independent Power Producers & Combined Heat and Power	2,137	29
Net Generation (megawatthours)	47,099,368	29
Electric Utilities	39,731,986	28
Independent Power Producers & Combined Heat and Power	7,367,382	26
Emissions (thousand short tons)		
Sulfur Dioxide	14	44
Nitrogen Oxide	11	44
Carbon Dioxide	7,555	42
Sulfur Dioxide/sq. mile	0	48
Nitrogen Oxide/sq. mile	0	48
Carbon Dioxide/sq. mile	79	47
Utility and ESP Retail Electricity Sales (megawatthours)	45,255,173	29
Utility Retail Electricity Sales (megawatthours)	45,255,173	28
Direct Use (megawatthours)	479,926	30
Average Retail Price (cents/kWh)	6.32	24

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Oregon			
1. John Day	Hydro	USCE-North Pacific Division	2,484
2. The Dalles	Hydro	USCE-North Pacific Division	1,961
3. Bonneville	Hydro	USCE-North Pacific Division	1,212
4. McNary	Hydro	USCE-North Pacific Division	1,127
5. Hermiston Power Proje	Hydro	Hermiston Power Partnership	615
6. Boardman	Petroleum, Coal	Portland General Electric Co	557
7. Beaver	Petroleum, Gas	Portland General Electric Co	517
8. Klamath Cogeneration	Gas	Pacific Klamath Energy Inc	470
9. Hermiston Generating	Gas	Hermiston Generating Co LP	464
10. Hells Canyon	Hydro	Idaho Power Co	361

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Oregon					
A. Portland General Electric Co	18,771,884	7,058,334	7,001,390	4,612,264	99,896
B. PacifiCorp	12,981,130	5,013,064	4,497,997	3,419,264	50,805
C. City of Eugene	2,542,729	959,805	892,865	675,935	14,124
D. Central Lincoln People's Ut Dt	1,258,073	406,253	200,614	647,465	3,741
E. Umatilla Electric Coop	808,281	147,849	444,702	215,364	366
Total	36,362,097	13,585,305	13,037,568	9,570,292	168,932
Percentage of Utility Sales	80	77	87	78	34

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Oregon							
Coal	508	508	557	1.0	4.9	4.5	4.5
Petroleum	6	0	0	NM	.1	.0	.0
Natural Gas	148	354	24	−18.3	1.4	3.1	.2
Dual Fired	448	598	729	5.6	4.3	5.2	5.8
Hydroelectric	9,008	9,037	9,033	.0	86.5	79.2	72.4
Other Renewables	14	40	6	−10.0	.1	.3	.0
Total Electric Utilities	**10,133**	**10,537**	**10,348**	**.2**	**97.3**	**92.4**	**82.9**
Coal	13	13	10	−3.2	.1	.1	.1
Natural Gas	1	536	1,715	120.5	.0	4.7	13.7
Dual Fired	0	49	4	NM	.0	.4	.0
Hydroelectric	109	96	55	−7.3	1.0	.8	.4
Other Renewables	159	179	352	9.2	1.5	1.6	2.8
Total IPP's & Combined Heat and Power	**283**	**872**	**2,137**	**25.2**	**2.7**	**7.6**	**17.1**
Coal	521	521	567	.9	5.0	4.6	4.5
Petroleum	6	0	0	NM	.1	.0	.0
Natural Gas	150	890	1,739	31.3	1.4	7.8	13.9
Dual Fired	448	647	733	5.6	4.3	5.7	5.9
Hydroelectric	9,117	9,133	9,089	.0	87.5	80.0	72.8
Other Renewables	173	219	357	8.4	1.7	1.9	2.9
Total Electric Industry	**10,415**	**11,409**	**12,485**	**2.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Oregon							
Coal	3,502,742	1,500,879	3,768,531	0.8	8.4	2.9	8.0
Petroleum	32,365	10,942	5,893	−17.2	.1	.0	.0
Natural Gas	1,687,456	1,273,183	1,799,217	.7	4.0	2.4	3.8
Nuclear	−21,276	0	0	NM	−.1	.0	.0
Hydroelectric	35,531,031	46,283,275	34,158,327	−.4	84.8	88.3	72.5
Other Renewables	10,767	0	18	−50.9	.0	.0	.0
Total Electric Utilities	**40,743,085**	**49,068,279**	**39,731,986**	**−.3**	**97.2**	**93.6**	**84.4**
Coal	17,650	18,788	11,153	−5.0	.0	.0	.0
Petroleum	1,303	2,435	811	−5.1	.0	.0	.0
Natural Gas	90,611	2,324,287	6,013,677	59.4	.2	4.4	12.8
Hydroelectric	333,049	420,425	254,840	−2.9	.8	.8	.5
Other Renewables	723,887	578,640	1,086,902	4.6	1.7	1.1	2.3
Total IPP's & Combined Heat and Power	**1,166,500**	**3,344,575**	**7,367,382**	**22.7**	**2.8**	**6.4**	**15.6**
Coal	3,520,392	1,519,667	3,779,684	.8	8.4	2.9	8.0
Petroleum	33,668	13,377	6,704	−16.4	.1	.0	.0
Natural Gas	1,778,067	3,597,470	7,812,894	17.9	4.2	6.9	16.6
Nuclear	−21,276	0	0	NM	−.1	.0	.0
Hydroelectric	35,864,080	46,703,700	34,413,167	−.5	85.6	89.1	73.1
Other Renewables	734,654	578,640	1,086,920	4.4	1.8	1.1	2.3
Total Electric Industry	**41,909,585**	**52,412,854**	**47,099,369**	**1.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Oregon				
Coal (2002 cents per million Btu)	125.1	117.1	132.9	0.7
Average heat value (Btu per pound)	8,801	8,757	8,563	–.3
Average sulfur Content(percent)	.4	.3	.3	–2.2
Petroleum (2002 cents per million Btu)	426.8	503.8	572.3	3.3
Average heat value (Btu per gallon)	140,000	140,000	141,631	.1
Average sulfur Content(percent)	.0	.0	*	NM
Gas (2002 cents per million Btu)	251.0	151.7	328.4	3.0
Average heat value (Btu per cubic foot)	1,011	1,011	1,019	.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Oregon				
Sulfur Dioxide				
Coal	13	7	12	–0.7
Petroleum	*	*	*	–9.2
Gas	0	*	*	NM
Other	*	1	1	19.7
Total	14	7	14	.1
Nitrogen Oxide				
Coal	15	3	8	–6.4
Petroleum	*	*	0	NM
Gas	2	1	2	–4.0
Other	1	1	1	.8
Total	18	5	11	–5.7
Carbon Dioxide				
Coal	3,728	1,561	3,998	.8
Petroleum	27	15	7	–13.4
Gas	1,034	1,698	3,530	14.6
Other	22	22	21	–.6
Total	4,811	3,296	7,555	5.1

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Oregon							
Retail Sales (thousand megawatthours)							
Residential	16,696	17,185	17,554	0.6	37.4	36.1	38.8
Commercial	12,205	14,047	14,902	2.2	27.4	29.5	32.9
Industrial	15,012	15,931	12,296	–2.2	33.7	33.5	27.2
Other	664	440	503	–3.0	1.5	.9	1.1
Total	44,578	47,603	45,255	.2	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	934	983	1,249	3.3	42.4	43.5	43.7
Commercial	670	717	982	4.3	30.5	31.8	34.3
Industrial	556	528	581	.5	25.3	23.4	20.3
Other	39	29	48	2.1	1.8	1.3	1.7
Total	2,199	2,257	2,859	3.0	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	5.59	5.72	7.12	2.7	NA	NA	NA
Commercial	5.49	5.11	6.59	2.0	NA	NA	NA
Industrial	3.71	3.32	4.72	2.7	NA	NA	NA
Other	5.94	6.62	9.44	5.3	NA	NA	NA
Total	4.93	4.74	6.32	2.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Oregon						
Number of Entities	1	24	0	16	0	41
Number of Retail Customers	741,949	795,521	0	177,134	0	1,714,604
Retail Sales (thousand megawatthours)	18,772	22,237	0	4,247	0	45,255
Percentage of Retail Sales	41.48	49.14	.00	9.38	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,384	1,194	0	281	0	2,859
Percentage of Revenue	48.41	41.76	.00	9.83	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.37	5.37	.00	6.62	0	6.32

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Pennsylvania		
NERC Region(s)		ECAR/MACC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	39,783	5
Electric Utilities	4,887	34
Independent Power Producers & Combined Heat and Power	34,896	3
Net Generation (megawatthours)	204,322,878	2
Electric Utilities	30,537,243	33
Independent Power Producers & Combined Heat and Power	173,785,635	2
Emissions (thousand short tons)		
Sulfur Dioxide	892	2
Nitrogen Oxide	224	6
Carbon Dioxide	125,225	5
Sulfur Dioxide/sq. mile	19	5
Nitrogen Oxide/sq. mile	5	10
Carbon Dioxide/sq. mile	2,719	10
Utility and ESP Retail Electricity Sales (megawatthours)	140,786,670	6
Utility Retail Electricity Sales (megawatthours)	129,654,562	5
ESP Retail Electricity Sales (megawatthours)	11,132,108	5
Direct Use (megawatthours)	–454,086	49
Average Retail Price (cents/kWh)	8.01	13

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Pennsylvania			
1. Bruce Mansfield	Petroleum, Coal	Pennsylvania Power Co	2,360
2. Limerick	Nuclear	Exelon Generation Co LLC	2,268
3. PPL Susquehanna	Nuclear	PPL Susquehanna LLC	2,216
4. Peach Bottom	Nuclear	Exelon Generation Co LLC	2,186
5. PPL Martins Creek	Gas, Petroleum, Coal	PPL Martins Creek LLC	2,027
6. Homer City Station	Coal	Midwest Generations EME LLC	1,884
7. Conemaugh	Petroleum, Gas, Coal	Reliant Energy Mid-Atlantic PH	1,712
8. Keystone	Petroleum, Coal	Reliant Energy Mid-Atlantic PH	1,712
9. Beaver Valley	Nuclear	Pennsylvania Power Co	1,641
10. Hatfields Ferry Power	Gas, Petroleum, Coal	Allegheny Energy Supply Co LLC	1,590

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Pennsylvania					
A. PECO Energy Company	33,687,140	10,364,563	7,604,030	14,765,926	952,621
B. Pennsylvania Power & Light Co	33,631,765	12,592,661	11,665,339	9,200,387	173,378
C. West Penn Power Company	19,007,704	6,459,672	4,520,735	7,975,017	52,280
D. Pennsylvania Electric Company	12,391,335	4,154,844	4,686,868	3,508,037	41,586
E. Metropolitan Edison Company	10,993,418	4,718,826	3,869,957	2,369,628	35,007
Total	109,711,362	38,290,566	32,346,929	37,818,995	1,254,872
Percentage of Utility Sales	78	78	72	83	88

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Pennsylvania							
Coal	17,480	17,386	2,360	-19.9	48.8	47.4	5.9
Petroleum	4,115	2,225	0	NM	11.5	6.1	.0
Natural Gas	242	2,078	0	NM	.7	5.7	.0
Dual Fired	965	1,188	7	-41.9	2.7	3.2	.0
Nuclear	8,709	9,006	1,641	-16.9	24.3	24.6	4.1
Hydroelectric	1,912	1,942	879	-8.3	5.3	5.3	2.2
Total Electric Utilities	**33,423**	**33,825**	**4,887**	**-19.2**	**93.4**	**92.3**	**12.3**
Coal	1,294	1,568	16,024	32.3	3.6	4.3	40.3
Petroleum	15	15	2,283	74.9	.0	.0	5.7
Natural Gas	234	292	2,482	30.0	.7	.8	6.2
Other Gases	251	189	105	-9.3	.7	.5	.3
Dual Fired	264	389	4,822	38.1	.7	1.1	12.1
Nuclear	0	0	7,486	NM	.0	.0	18.8
Hydroelectric	85	84	1,217	34.4	.2	.2	3.1
Other Renewables	232	286	477	8.3	.6	.8	1.2
Other	2	2	0	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**2,378**	**2,825**	**34,896**	**34.8**	**6.6**	**7.7**	**87.7**
Coal	18,774	18,954	18,384	-.2	52.4	51.7	46.2
Petroleum	4,130	2,240	2,283	-6.4	11.5	6.1	5.7
Natural Gas	476	2,370	2,482	20.1	1.3	6.5	6.2
Other Gases	251	189	105	-9.3	.7	.5	.3
Dual Fired	1,229	1,577	4,829	16.4	3.4	4.3	12.1
Nuclear	8,709	9,006	9,127	.5	24.3	24.6	22.9
Hydroelectric	1,997	2,026	2,096	.5	5.6	5.5	5.3
Other Renewables	232	286	477	8.3	.6	.8	1.2
Other	2	2	0	NM	.0	.0	.0
Total Electric Industry	**35,801**	**36,650**	**39,783**	**1.2**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Pennsylvania							
Coal	100,390,066	105,445,514	15,935,860	-18.5	55.4	54.5	7.8
Petroleum	4,559,186	2,307,411	39,420	-41.0	2.5	1.2	.0
Natural Gas	796,697	611,049	1,934	-48.8	.4	.3	.0
Nuclear	59,330,534	67,654,588	13,594,705	-15.1	32.7	35.0	6.7
Hydroelectric	1,124,203	1,147,954	965,324	-1.7	.6	.6	.5
Total Electric Utilities	**166,200,686**	**177,166,516**	**30,537,243**	**-17.2**	**91.7**	**91.6**	**14.9**
Coal	7,741,753	10,058,989	97,970,580	32.6	4.3	5.2	47.9
Petroleum	454,135	397,697	2,693,525	21.9	.3	.2	1.3
Natural Gas	3,072,971	2,043,854	6,713,603	9.1	1.7	1.1	3.3
Other Gases	1,097,976	756,189	568,725	-7.0	.6	.4	.3
Nuclear	0	0	62,494,225	NM	.0	.0	30.6
Hydroelectric	368,216	470,117	587,485	5.3	.2	.2	.3
Other Renewables	2,070,887	2,540,879	2,757,492	3.2	1.1	1.3	1.3
Other	207,510	28,955	0	NM	.1	.0	.0
Total IPP's & Combined Heat and Power	**15,013,448**	**16,296,680**	**173,785,635**	**31.3**	**8.3**	**8.4**	**85.1**
Coal	108,131,819	115,504,503	113,906,440	.6	59.7	59.7	55.7
Petroleum	5,013,321	2,705,108	2,732,945	-6.5	2.8	1.4	1.3
Natural Gas	3,869,668	2,654,903	6,715,537	6.3	2.1	1.4	3.3
Other Gases	1,097,976	756,189	568,725	-7.0	.6	.4	.3
Nuclear	59,330,534	67,654,588	76,088,930	2.8	32.7	35.0	37.2
Hydroelectric	1,492,419	1,618,071	1,552,809	.4	.8	.8	.8
Other Renewables	2,070,887	2,540,879	2,757,492	3.2	1.1	1.3	1.3
Other	207,510	28,955	0	NM	.1	.0	.0
Total Electric Industry	**181,214,134**	**193,463,196**	**204,322,878**	**1.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Pennsylvania				
Coal (2002 cents per million Btu)	160.1	139.3	125.3	-2.7
Average heat value (Btu per pound)	12,443	12,279	11,782	-.6
Average sulfur Content(percent)	2.1	2.1	1.9	-.7
Petroleum (2002 cents per million Btu)	263.4	230.9	463.9	6.5
Average heat value (Btu per gallon)	141,623	126,593	143,421	.1
Average sulfur Content(percent)	1.2	2.3	.5	-9.4
Gas (2002 cents per million Btu)	287.2	300.6	389.9	3.4
Average heat value (Btu per cubic foot)	1,030	1,034	1,027	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Pennsylvania				
Sulfur Dioxide				
Coal	1,209	1,103	885	-3.4
Petroleum	41	25	7	-18.0
Gas	*	*	*	-8.7
Other	1	2	*	-15.0
Total	1,252	1,130	892	-3.7
Nitrogen Oxide				
Coal	370	278	211	-6.1
Petroleum	8	4	3	-10.0
Gas	18	12	4	-15.9
Other	4	4	6	3.9
Total	401	298	224	-6.3
Carbon Dioxide				
Coal	110,919	117,557	118,524	.7
Petroleum	5,023	2,927	2,844	-6.1
Gas	2,940	1,955	3,500	2.0
Other	283	351	356	2.6
Total	119,166	122,790	125,225	.5

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Pennsylvania							
Retail Sales (thousand megawatthours)							
Residential	41,455	42,715	48,876	1.8	34.5	33.4	34.7
Commercial	32,252	35,899	45,115	3.8	26.9	28.1	32.0
Industrial	44,949	47,957	45,367	.1	37.5	37.5	32.2
Other	1,325	1,304	1,430	.8	1.1	1.0	1.0
Total	119,981	127,875	140,787	1.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	4,410	4,344	4,747	.8	41.7	41.3	42.1
Commercial	2,979	3,102	3,623	2.2	28.1	29.5	32.1
Industrial	3,022	2,900	2,747	-1.0	28.6	27.6	24.4
Other	171	157	159	-.8	1.6	1.5	1.4
Total	10,582	10,503	11,276	.7	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	10.64	10.17	9.71	-1.0	NA	NA	NA
Commercial	9.24	8.64	8.03	-1.5	NA	NA	NA
Industrial	6.72	6.05	6.06	-1.1	NA	NA	NA
Other	12.88	12.04	11.10	-1.6	NA	NA	NA
Total	8.82	8.21	8.01	-1.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Pennsylvania						
Number of Entities	10	36	0	13	20	79
Number of Retail Customers	4,363,782	660,382	0	205,487	462,446	5,692,097
Retail Sales (thousand megawatthours)	113,585	13,797	0	2,273	11,132	140,787
Percentage of Retail Sales	80.68	9.80	.00	1.61	7.91	100.00
Revenue from Retail Sales (million 2002 dollars)	9,390	1,053	0	237	597	11,276
Percentage of Revenue	83.27	9.34	.00	2.10	5.29	100.00
Revenue per Kilowatthour (2002 cents/kWh)	8.27	7.63	.00	10.41	0	8.01

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Rhode Island		
NERC Region(s)		NPCC
Primary Energy Source		Gas
Net Summer Capability (megawatts)	1,723	49
Electric Utilities	9	50
Independent Power Producers & Combined Heat and Power	1,715	33
Net Generation (megawatthours)	7,056,765	47
Electric Utilities	11,836	49
Independent Power Producers & Combined Heat and Power	7,044,929	29
Emissions (thousand short tons)		
Sulfur Dioxide	0	50
Nitrogen Oxide	1	49
Carbon Dioxide	3,294	48
Sulfur Dioxide/sq. mile	0	40
Nitrogen Oxide/sq. mile	1	29
Carbon Dioxide/sq. mile	3,152	7
Utility and ESP Retail Electricity Sales (megawatthours)	7,543,652	49
Utility Retail Electricity Sales (megawatthours)	6,633,124	47
ESP Retail Electricity Sales (megawatthours)	910,528	14
Direct Use (megawatthours)	-12,999	44
Average Retail Price (cents/kWh)	9.19	11

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Rhode Island			
1. Rhode Island State En	Gas	FPL Energy Operating Serv Inc	515
2. Manchester Street	Petroleum, Gas	U S Gen New England Inc	421
3. Tiverton Power Plant	Other, Gas	Calpine Eastern Corp	239
4. Ocean State Power	Gas	Ocean State Power Co	219
5. Ocean State Power II	Gas	Ocean State Power II	219
6. Pawtucket Power Assoc	Petroleum, Gas	Pawtucket Power Associates LP	64
7. Ridgewood Providence	Other	Ridgewood Power Management LLC	15
8. Rhode Island Hospital	Gas, Petroleum	Rhode Island Hospital	10
9. Block Island	Petroleum	Block Island Power Co	7
10. Central Power Plant	Petroleum	State of Rhode Island	5

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Rhode Island					
A. Narragansett Electric Company	6,575,579	2,796,307	2,825,954	941,882	11,436
B. Select Energy	362,119	0	102,672	2,108	257,339
C. TransCanada Power Market'g Ltd	323,762	0	0	323,762	0
D. New Energy Ventures, Inc	221,957	0	221,957	0	0
E. Pascoag Fire District	47,387	25,501	4,686	16,604	596
Total	7,530,804	2,821,808	3,155,269	1,284,356	269,371
Percentage of Utility Sales	100	100	100	100	100

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Rhode Island							
Petroleum	68	20	7	-22.0	9.9	2.0	0.4
Natural Gas	0	420	0	NM	.0	42.8	.0
Dual Fired	84	0	0	NM	12.3	.0	.0
Hydroelectric	1	1	1	-.5	.2	.1	.1
Total Electric Utilities	153	441	9	-27.3	22.4	45.0	.5
Petroleum	0	1	5	NM	.0	.1	.3
Natural Gas	0	0	906	NM	.0	.0	52.6
Dual Fired	515	521	785	4.8	75.3	53.1	45.6
Hydroelectric	3	3	3	.2	.4	.3	.2
Other Renewables	13	15	15	1.6	1.9	1.5	.9
Total IPP's & Combined Heat and Power	531	540	1,715	13.9	77.6	55.0	99.5
Petroleum	68	20	12	-17.2	9.9	2.1	.7
Natural Gas	0	420	906	NM	.0	42.8	52.6
Dual Fired	599	521	785	3.1	87.6	53.1	45.6
Hydroelectric	4	4	4	-.1	.6	.4	.2
Other Renewables	13	15	15	1.6	1.9	1.5	.9
Total Electric Industry	684	981	1,723	10.8	100.0	100.0	100.0

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Rhode Island							
Petroleum	28,582	16,609	11,836	-9.3	0.6	0.2	0.2
Natural Gas	25,158	3,546,224	0	NM	.5	46.0	.0
Total Electric Utilities	53,740	3,562,833	11,836	-15.5	1.2	46.2	.2
Petroleum	43,899	72,441	45,697	.4	.9	.9	.6
Natural Gas	4,483,473	3,962,181	6,310,417	3.9	96.1	51.4	89.4
Hydroelectric	9,385	7,509	3,685	-9.9	.2	.1	.1
Other Renewables	74,798	104,590	97,752	3.0	1.6	1.4	1.4
Other	0	0	587,378	NM	.0	.0	8.3
Total IPP's & Combined Heat and Power	4,611,556	4,146,721	7,044,929	4.8	98.8	53.8	99.8
Petroleum	72,481	89,050	57,533	-2.5	1.6	1.2	.8
Natural Gas	4,508,631	7,508,405	6,310,417	3.8	96.6	97.4	89.4
Hydroelectric	9,385	7,509	3,685	-9.9	.2	.1	.1
Other Renewables	74,798	104,590	97,752	3.0	1.6	1.4	1.4
Other	0	0	587,378	NM	.0	.0	8.3
Total Electric Industry	4,665,296	7,709,554	7,056,765	4.7	100.0	100.0	100.0

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Rhode Island				
Petroleum (2002 cents per million Btu)	356.4	0.0	0.0	NM
Average heat value (Btu per gallon)	150,389	0	149,845	*
Average sulfur Content(percent)	1.0	.0	.0	NM
Gas (2002 cents per million Btu)	266.4	335.4	455.4	6.1
Average heat value (Btu per cubic foot)	1,051	1,027	1,018	–.3

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Rhode Island				
Sulfur Dioxide				
Petroleum	1	1	*	–4.2
Gas	*	*	*	–1.2
Total	1	1	1	–4.2
Nitrogen Oxide				
Petroleum	*	*	*	–5.5
Gas	2	4	1	–9.0
Other	*	*	1	1.3
Total	2	5	1	–5.8
Carbon Dioxide				
Petroleum	132	113	85	–4.8
Gas	2,143	3,638	3,209	4.6
Total	2,275	3,751	3,294	4.2

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Rhode Island							
Retail Sales (thousand megawatthours)							
Residential	2,412	2,486	2,826	1.8	36.8	37.1	37.5
Commercial	2,532	2,652	3,164	2.5	38.7	39.6	41.9
Industrial	1,419	1,380	1,285	-1.1	21.7	20.6	17.0
Other	186	174	269	4.2	2.8	2.6	3.6
Total	6,548	6,693	7,544	1.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	306	310	289	-.6	40.3	42.1	41.6
Commercial	287	283	280	-.3	37.8	38.5	40.3
Industrial	143	121	103	-3.5	18.8	16.4	14.9
Other	23	22	22	-.6	3.0	3.0	3.1
Total	759	736	693	-1.0	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	12.68	12.45	10.21	-2.4	NA	NA	NA
Commercial	11.33	10.69	8.84	-2.7	NA	NA	NA
Industrial	10.06	8.76	8.04	-2.4	NA	NA	NA
Other	12.41	12.69	8.09	-4.6	NA	NA	NA
Total	11.58	11.00	9.19	-2.5	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Rhode Island						
Number of Entities	2	1	0	0	4	7
Number of Retail Customers	465,564	4,291	0	0	1,694	471,549
Retail Sales (thousand megawatthours)	6,586	47	0	0	911	7,544
Percentage of Retail Sales	87.30	.63	.00	.00	12.07	100.00
Revenue from Retail Sales (million 2002 dollars)	644	5	0	0	45	693
Percentage of Revenue	92.84	.68	.00	.00	6.49	100.00
Revenue per Kilowatthour (2002 cents/kWh)	9.77	9.88	.00	.00	0	9.19

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
South Carolina		
NERC Region(s)		SERC
Primary Energy Source		Nuclear
Net Summer Capability (megawatts)	20,363	16
Electric Utilities	19,101	12
Independent Power Producers & Combined Heat and Power	1,262	37
Net Generation (megawatthours)	96,563,498	14
Electric Utilities	93,689,257	9
Independent Power Producers & Combined Heat and Power	2,874,241	38
Emissions (thousand short tons)		
Sulfur Dioxide	216	19
Nitrogen Oxide	92	22
Carbon Dioxide	40,105	26
Sulfur Dioxide/sq. mile	7	16
Nitrogen Oxide/sq. mile	3	16
Carbon Dioxide/sq. mile	1,332	21
Utility and ESP Retail Electricity Sales (megawatthours)	77,819,392	17
Utility Retail Electricity Sales (megawatthours)	77,819,392	17
Direct Use (megawatthours)	1,601,683	22
Average Retail Price (cents/kWh)	5.83	37

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
South Carolina			
1. Oconee	Nuclear	Duke Energy Corp	2,538
2. Catawba	Nuclear	Duke Energy Corp	2,258
3. Cross	Petroleum, Coal	South Carolina Pub Serv Auth	1,160
4. Winyah	Petroleum, Coal	South Carolina Pub Serv Auth	1,155
5. Bad Creek	Hydro	Duke Energy Corp	1,065
6. V C Summer	Nuclear	South Carolina Electric&Gas Co	986
7. H B Robinson	Gas, Petroleum, Coal	Carolina Power & Light Co	899
8. Darlington County	Petroleum, Gas	Carolina Power & Light Co	812
9. Broad River Energy Ce	Gas	Broad River Energy LLC	802
10. John S Rainey	Gas	South Carolina Pub Serv Auth	744

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
South Carolina					
A. Duke Energy Corporation	21,378,725	5,877,145	5,044,924	10,411,519	45,137
B. South Carolina Electric&Gas Co	20,928,898	7,229,801	6,658,730	6,505,509	534,858
C. South Carolina Pub Serv Auth	11,156,755	1,395,584	1,719,639	7,970,307	71,225
D. Carolina Power & Light Company	7,103,316	2,122,401	1,703,543	3,186,442	90,930
E. Berkeley Electric Coop, Inc	1,373,745	1,042,397	123,432	153,241	54,675
Total	61,941,439	17,667,328	15,250,268	28,227,018	796,825
Percentage of Utility Sales	80	66	84	88	84

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
South Carolina							
Coal	4,812	5,794	5,925	2.3	29.0	32.5	29.1
Petroleum	287	671	669	9.9	1.7	3.8	3.3
Natural Gas	10	27	760	62.7	.1	.1	3.7
Other Gases	364	0	0	NM	2.2	.0	.0
Dual Fired	847	1,079	1,676	7.9	5.1	6.0	8.2
Nuclear	6,364	6,421	6,492	.2	38.4	36.0	31.9
Hydroelectric	3,448	3,439	3,579	.4	20.8	19.3	17.6
Total Electric Utilities	**16,131**	**17,431**	**19,101**	**1.9**	**97.3**	**97.7**	**93.8**
Coal	189	131	103	-6.5	1.1	.7	.5
Petroleum	1	1	3	11.0	.0	.0	.0
Natural Gas	1	1	399	89.2	.0	.0	2.0
Dual Fired	3	3	502	74.5	.0	.0	2.5
Hydroelectric	18	18	24	3.1	.1	.1	.1
Other Renewables	240	250	232	-.4	1.4	1.4	1.1
Total IPP's & Combined Heat and Power	**453**	**405**	**1,262**	**12.1**	**2.7**	**2.3**	**6.2**
Coal	5,001	5,925	6,028	2.1	30.2	33.2	29.6
Petroleum	288	672	672	9.9	1.7	3.8	3.3
Natural Gas	11	28	1,159	68.2	.1	.2	5.7
Other Gases	364	0	0	NM	2.2	.0	.0
Dual Fired	850	1,082	2,177	11.0	5.1	6.1	10.7
Nuclear	6,364	6,421	6,492	.2	38.4	36.0	31.9
Hydroelectric	3,466	3,458	3,603	.4	20.9	19.4	17.7
Other Renewables	240	250	232	-.4	1.4	1.4	1.1
Total Electric Industry	**16,584**	**17,836**	**20,363**	**2.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
South Carolina							
Coal	26,532,193	31,042,658	36,490,769	3.6	33.9	38.4	37.8
Petroleum	95,193	188,326	205,664	8.9	.1	.2	.2
Natural Gas	121,113	181,202	3,466,140	45.2	.2	.2	3.6
Nuclear	46,188,884	44,915,514	53,325,854	1.6	59.1	55.6	55.2
Hydroelectric	2,651,003	2,046,750	185,308	-25.6	3.4	2.5	.2
Other Renewables	0	0	15,522	NM	.0	.0	.0
Total Electric Utilities	**75,588,386**	**78,374,450**	**93,689,257**	**2.4**	**96.7**	**97.0**	**97.0**
Coal	707,766	531,716	456,953	-4.7	.9	.7	.5
Petroleum	107,045	175,679	94,673	-1.4	.1	.2	.1
Natural Gas	86,602	109,510	1,032,179	31.7	.1	.1	1.1
Other Gases	24,411	1,141	314	-38.4	.0	.0	.0
Hydroelectric	60,020	56,360	61,227	.2	.1	.1	.1
Other Renewables	1,593,086	1,574,159	1,228,895	-2.8	2.0	1.9	1.3
Other	7,517	5,045	0	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**2,586,447**	**2,453,609**	**2,874,241**	**1.2**	**3.3**	**3.0**	**3.0**
Coal	27,239,959	31,574,374	36,947,722	3.4	34.8	39.1	38.3
Petroleum	202,238	364,005	300,337	4.5	.3	.5	.3
Natural Gas	207,715	290,712	4,498,319	40.7	.3	.4	4.7
Other Gases	24,411	1,141	314	-38.4	.0	.0	.0
Nuclear	46,188,884	44,915,514	53,325,854	1.6	59.1	55.6	55.2
Hydroelectric	2,711,023	2,103,110	246,535	-23.4	3.5	2.6	.3
Other Renewables	1,593,086	1,574,159	1,244,417	-2.7	2.0	1.9	1.3
Other	7,517	5,045	0	NM	.0	.0	.0
Total Electric Industry	**78,174,833**	**80,828,059**	**96,563,498**	**2.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
South Carolina				
Coal (2002 cents per million Btu)	174.9	148.8	158.8	-1.1
Average heat value (Btu per pound)	12,802	12,855	12,361	-.4
Average sulfur Content(percent)	1.2	1.2	1.2	*
Petroleum (2002 cents per million Btu)	474.4	466.7	466.0	-.2
Average heat value (Btu per gallon)	138,144	138,068	144,638	.5
Average sulfur Content(percent)	.0	.0	1.2	NM
Gas (2002 cents per million Btu)	324.5	408.6	270.1	-2.0
Average heat value (Btu per cubic foot)	1,021	1,024	1,028	.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
South Carolina				
Sulfur Dioxide				
Coal	185	196	208	1.3
Petroleum	1	1	2	17.9
Gas	0	0	0	NM
Other	4	4	5	4.2
Total	189	201	216	1.5
Nitrogen Oxide				
Coal	92	106	88	–.4
Petroleum	*	*	*	3.3
Gas	1	*	1	–2.4
Other	1	1	2	6.7
Total	94	107	92	–.3
Carbon Dioxide				
Coal	27,680	32,072	37,527	3.4
Petroleum	198	376	338	6.1
Gas	169	235	2,240	33.2
Other	8	10	0	NM
Total	28,056	32,693	40,105	4.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
South Carolina							
Retail Sales (thousand megawatthours)							
Residential	20,687	21,611	26,787	2.9	33.6	31.5	34.4
Commercial	13,177	14,806	18,157	3.6	21.4	21.6	23.3
Industrial	26,867	31,278	31,926	1.9	43.7	45.6	41.0
Other	802	840	950	1.9	1.3	1.2	1.2
Total	61,533	68,534	77,819	2.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,689	1,668	2,069	2.3	43.7	43.0	45.6
Commercial	914	963	1,177	2.9	23.6	24.8	25.9
Industrial	1,214	1,193	1,229	.1	31.4	30.8	27.1
Other	51	52	61	2.1	1.3	1.3	1.3
Total	3,868	3,875	4,537	1.8	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.17	7.72	7.72	–.6	NA	NA	NA
Commercial	6.93	6.50	6.48	–.7	NA	NA	NA
Industrial	4.52	3.81	3.85	–1.8	NA	NA	NA
Other	6.32	6.21	6.44	.2	NA	NA	NA
Total	6.29	5.65	5.83	–.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
South Carolina						
Number of Entities	2	26	0	19	0	47
Number of Retail Customers	560,167	982,091	0	602,562	0	2,144,820
Retail Sales (thousand megawatthours)	21,135	43,779	0	12,906	0	77,819
Percentage of Retail Sales	27.16	56.26	.00	16.58	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	1,305	2,308	0	923	0	4,537
Percentage of Revenue	28.77	50.88	.00	20.35	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.18	5.27	.00	7.15	0	5.83

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
South Dakota		
NERC Region(s)		WSCC/MAPP
Primary Energy Source		Hydro
Net Summer Capability (megawatts)	2,854	46
Electric Utilities	2,854	37
Net Generation (megawatthours)	7,721,958	46
Electric Utilities	7,721,958	39
Emissions (thousand short tons)		
Sulfur Dioxide	13	45
Nitrogen Oxide	16	40
Carbon Dioxide	3,845	47
Sulfur Dioxide/sq. mile	0	47
Nitrogen Oxide/sq. mile	0	47
Carbon Dioxide/sq. mile	51	48
Utility and ESP Retail Electricity Sales (megawatthours)	8,936,801	48
Utility Retail Electricity Sales (megawatthours)	8,936,801	46
Average Retail Price (cents/kWh)	6.26	27

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
South Dakota			
1. Oahe	Hydro	USCE-Missouri River District	714
2. Big Bend	Hydro	USCE-Missouri River District	509
3. Big Stone	Petroleum, Coal	Otter Tail Power Co	456
4. Fort Randall	Hydro	USCE-Missouri River District	353
5. Angus Anson	Petroleum, Gas	Northern States Power Co	229
6. Gavins Point	Hydro	USCE-Missouri River District	102
7. Ben French	Petroleum, Gas, Coal	Black Hills Corp	100
8. Spirit Mound	Petroleum	Basin Electric Power Coop	96
9. Pathfinder	Gas	Northern States Power Co	61
10. Huron	Gas	Northwestern Public Service Co	55

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
South Dakota					
A. Northern States Power Company	1,649,284	557,369	751,330	331,848	8,737
B. Black Hills Power Inc	1,358,155	436,721	601,416	294,073	25,945
C. NorthWestern Public Service Co	1,189,391	458,557	504,069	209,290	17,475
D. Sioux Valley Southwestern El	330,579	208,588	69,196	49,073	3,722
E. Western Area Power Admin	317,363	0	0	0	317,363
Total	4,844,772	1,661,235	1,926,011	884,284	373,242
Percentage of Utility Sales	*54*	*45*	*63*	*55*	*69*

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
South Dakota							
Coal	467	467	477	0.2	17.1	16.0	16.7
Petroleum	223	208	238	.7	8.2	7.1	8.3
Natural Gas	86	293	324	15.9	3.1	10.0	11.3
Dual Fired	138	138	135	–.2	5.0	4.7	4.7
Hydroelectric	1,820	1,820	1,678	–.9	66.6	62.2	58.8
Other Renewables	0	0	3	NM	.0	.0	.1
Total Electric Utilities	**2,733**	**2,927**	**2,854**	**.5**	**100.0**	**100.0**	**100.0**
Coal	467	467	477	.2	17.1	16.0	16.7
Petroleum	223	208	238	.7	8.2	7.1	8.3
Natural Gas	86	293	324	15.9	3.1	10.0	11.3
Dual Fired	138	138	135	–.2	5.0	4.7	4.7
Hydroelectric	1,820	1,820	1,678	–.9	66.6	62.2	58.8
Other Renewables	0	0	3	NM	.0	.0	.1
Total Electric Industry	**2,733**	**2,927**	**2,854**	**.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
South Dakota							
Coal	2,641,582	3,314,068	3,271,523	2.4	50.3	26.6	42.4
Petroleum	12,287	6,536	4,961	–9.6	.2	.1	.1
Natural Gas	10,527	116,637	85,778	26.2	.2	.9	1.1
Hydroelectric	2,591,115	9,012,260	4,353,653	5.9	49.3	72.4	56.4
Other Renewables	0	0	6,043	NM	.0	.0	.1
Total Electric Utilities	**5,255,511**	**12,449,501**	**7,721,958**	**4.4**	**100.0**	**100.0**	**100.0**
Coal	2,641,582	3,314,068	3,271,523	2.4	50.3	26.6	42.4
Petroleum	12,287	6,536	4,961	–9.6	.2	.1	.1
Natural Gas	10,527	116,637	85,778	26.2	.2	.9	1.1
Hydroelectric	2,591,115	9,012,260	4,353,653	5.9	49.3	72.4	56.4
Other Renewables	0	0	6,043	NM	.0	.0	.1
Total Electric Industry	**5,255,511**	**12,449,501**	**7,721,958**	**4.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
South Dakota				
Coal (2002 cents per million Btu)	122.4	94.6	129.5	0.6
Average heat value (Btu per pound)	6,057	8,687	8,477	3.8
Average sulfur Content(percent)	.9	.6	.4	–9.4
Petroleum (2002 cents per million Btu)	520.9	.0	.0	NM
Average heat value (Btu per gallon)	140,000	0	139,945	.0
Gas (2002 cents per million Btu)	265.1	.0	.0	NM
Average heat value (Btu per cubic foot)	1,014	0	980	–.4

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
South Dakota				
Sulfur Dioxide				
Coal	31	25	13	–9.5
Petroleum	*	*	0	NM
Other	0	*	0	NM
Total	31	25	13	–9.5
Nitrogen Oxide				
Coal	19	24	16	–1.4
Petroleum	*	0	0	NM
Gas	*	*	*	13.1
Other	0	*	0	NM
Total	19	24	16	–1.3
Carbon Dioxide				
Coal	3,294	3,760	3,762	1.5
Petroleum	15	11	7	–8.3
Gas	11	103	76	23.9
Total	3,320	3,873	3,845	1.6

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
South Dakota							
Retail Sales (thousand megawatthours)							
Residential	3,109	3,376	3,733	2.0	45.0	43.4	41.8
Commercial	1,621	2,207	3,062	7.3	23.5	28.4	34.3
Industrial	1,847	1,841	1,604	−1.6	26.8	23.7	17.9
Other	327	349	538	5.7	4.7	4.5	6.0
Total	6,905	7,773	8,937	2.9	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	244	246	276	1.4	51.1	49.5	49.3
Commercial	122	150	191	5.1	25.5	30.3	34.1
Industrial	95	84	73	−2.9	19.8	16.8	13.0
Other	17	17	20	1.8	3.5	3.4	3.5
Total	477	497	560	1.8	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.84	7.28	7.40	−.6	NA	NA	NA
Commercial	7.51	6.82	6.24	−2.0	NA	NA	NA
Industrial	5.12	4.55	4.54	−1.3	NA	NA	NA
Other	5.07	4.85	3.63	−3.6	NA	NA	NA
Total	6.91	6.39	6.26	−1.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
South Dakota						
Number of Entities	1	49	0	23	0	73
Number of Retail Customers	57,406	242,439	0	95,186	0	395,031
Retail Sales (thousand megawatthours)	1,189	5,939	0	1,808	0	8,937
Percentage of Retail Sales	13.31	66.46	.00	20.23	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	83	346	0	131	0	560
Percentage of Revenue	14.88	61.75	.00	23.37	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.00	5.82	.00	7.24	0	6.26

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Tennessee		
NERC Region(s)		ECAR/SERC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	20,723	15
Electric Utilities	19,136	11
Independent Power Producers & Combined Heat and Power	1,587	34
Net Generation (megawatthours)	96,114,261	15
Electric Utilities	92,570,929	10
Independent Power Producers & Combined Heat and Power	3,543,332	37
Emissions (thousand short tons)		
Sulfur Dioxide	345	13
Nitrogen Oxide	162	12
Carbon Dioxide	63,214	14
Sulfur Dioxide/sq. mile	8	14
Nitrogen Oxide/sq. mile	4	12
Carbon Dioxide/sq. mile	1,534	17
Utility and ESP Retail Electricity Sales (megawatthours)	98,233,027	13
Utility Retail Electricity Sales (megawatthours)	98,233,027	13
Direct Use (megawatthours)	3,200,072	12
Average Retail Price (cents/kWh)	5.72	40

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Tennessee			
1. Cumberland	Petroleum, Coal	Tennessee Valley Authority	2,455
2. Johnsonville	Gas, Petroleum, Coal	Tennessee Valley Authority	2,318
3. Sequoyah	Nuclear	Tennessee Valley Authority	2,251
4. Raccoon Mountain	Hydro	Tennessee Valley Authority	1,624
5. Gallatin	Gas, Petroleum, Coal	Tennessee Valley Authority	1,572
6. Kingston	Petroleum, Coal	Tennessee Valley Authority	1,434
7. Allen Steam Plant	Petroleum, Gas, Coal	Tennessee Valley Authority	1,194
8. Watts Bar Nuclear Pla	Nuclear	Tennessee Valley Authority	1,138
9. Lagoon Creek	Nuclear	Tennessee Valley Authority	952
10. Bull Run	Petroleum, Coal	Tennessee Valley Authority	865

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Tennessee					
A. City of Memphis	14,292,842	5,447,177	4,663,000	4,034,209	148,456
B. Nashville Electric Service	12,148,170	4,553,217	4,328,996	3,145,532	120,425
C. Tennessee Valley Authority	8,733,791	0	0	8,724,908	8,883
D. City of Chattanooga	5,751,011	2,042,047	1,830,556	1,821,473	56,935
E. City of Knoxville	5,450,450	2,422,073	1,681,845	1,282,462	64,070
Total	46,376,264	14,464,514	12,504,397	19,008,584	398,769
Percentage of Utility Sales	47	37	47	60	36

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Tennessee							
Coal	8,691	8,604	8,602	–0.1	52.2	47.9	41.5
Petroleum	0	0	56	NM	.0	.0	.3
Dual Fired	1,568	1,649	3,116	7.9	9.4	9.2	15.0
Nuclear	2,217	3,357	3,389	4.8	13.3	18.7	16.4
Hydroelectric	3,748	3,751	3,972	.6	22.5	20.9	19.2
Other Renewables	0	0	2	NM	.0	.0	.0
Total Electric Utilities	**16,224**	**17,361**	**19,137**	**1.9**	**97.5**	**96.6**	**92.3**
Coal	286	309	276	–.4	1.7	1.7	1.3
Natural Gas	28	28	1,034	49.3	.2	.2	5.0
Other Gases	0	5	0	NM	.0	.0	.0
Dual Fired	0	4	0	NM	.0	.0	.0
Hydroelectric	0	170	165	NM	.0	.9	.8
Other Renewables	62	50	112	6.8	.4	.3	.5
Other	38	38	0	NM	.2	.2	.0
Total IPP's & Combined Heat and Power	**414**	**604**	**1,587**	**16.1**	**2.5**	**3.4**	**7.7**
Coal	8,977	8,913	8,878	–.1	54.0	49.6	42.8
Petroleum	0	0	56	NM	.0	.0	.3
Natural Gas	28	28	1,034	49.3	.2	.2	5.0
Other Gases	0	5	0	NM	.0	.0	.0
Dual Fired	1,568	1,653	3,116	7.9	9.4	9.2	15.0
Nuclear	2,217	3,357	3,389	4.8	13.3	18.7	16.4
Hydroelectric	3,748	3,921	4,137	1.1	22.5	21.8	20.0
Other Renewables	62	50	114	7.0	.4	.3	.6
Other	38	38	0	NM	.2	.2	.0
Total Electric Industry	**16,639**	**17,965**	**20,723**	**2.5**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Tennessee							
Coal	59,559,596	58,899,058	58,080,553	-0.3	80.6	60.8	60.4
Petroleum	234,545	192,880	250,325	.7	.3	.2	.3
Natural Gas	121,222	152,081	40,414	-11.5	.2	.2	.0
Nuclear	3,304,836	24,647,994	27,573,925	26.6	4.5	25.5	28.7
Hydroelectric	8,394,069	9,401,219	6,621,644	-2.6	11.4	9.7	6.9
Other Renewables	0	0	4,068	NM	.0	.0	.0
Total Electric Utilities	**71,614,268**	**93,293,232**	**92,570,929**	**2.9**	**96.9**	**96.4**	**96.3**
Coal	1,535,227	1,618,639	1,625,128	.6	2.1	1.7	1.7
Petroleum	4,561	4,730	19,288	17.4	.0	.0	.0
Natural Gas	171,504	204,505	429,159	10.7	.2	.2	.4
Other Gases	2,681	17,555	11,873	18.0	.0	.0	.0
Hydroelectric	0	964,685	656,175	NM	.0	1.0	.7
Other Renewables	487,722	595,285	798,396	5.6	.7	.6	.8
Other	68,236	115,440	3,314	-28.5	.1	.1	.0
Total IPP's & Combined Heat and Power	**2,269,931**	**3,520,839**	**3,543,332**	**5.1**	**3.1**	**3.6**	**3.7**
Coal	61,094,823	60,517,697	59,705,681	-.3	82.7	62.5	62.1
Petroleum	239,106	197,610	269,613	1.3	.3	.2	.3
Natural Gas	292,726	356,586	469,573	5.4	.4	.4	.5
Other Gases	2,681	17,555	11,873	18.0	.0	.0	.0
Nuclear	3,304,836	24,647,994	27,573,925	26.6	4.5	25.5	28.7
Hydroelectric	8,394,069	10,365,904	7,277,819	-1.6	11.4	10.7	7.6
Other Renewables	487,722	595,285	802,464	5.7	.7	.6	.8
Other	68,236	115,440	3,314	-28.5	.1	.1	.0
Total Electric Industry	**73,884,199**	**96,814,071**	**96,114,261**	**3.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Tennessee				
Coal (2002 cents per million Btu)	140.6	115.6	121.7	-1.6
Average heat value (Btu per pound)	12,268	11,855	11,631	-.6
Average sulfur Content(percent)	1.9	1.9	1.3	-4.1
Petroleum (2002 cents per million Btu)	480.8	451.2	536.3	1.2
Average heat value (Btu per gallon)	138,361	139,900	138,486	*
Average sulfur Content(percent)	.0	.0	.5	NM
Gas (2002 cents per million Btu)	.0	.0	322.6	NM
Average heat value (Btu per cubic foot)	0	0	1,024	NM

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Tennessee				
Sulfur Dioxide				
Coal	847	529	341	-9.6
Petroleum	*	*	*	6.7
Gas	0	0	0	NM
Other	1	2	4	11.3
Total	849	531	345	-9.5
Nitrogen Oxide				
Coal	229	282	160	-3.9
Petroleum	*	*	*	2.2
Gas	1	1	1	3.7
Other	1	1	1	9.6
Total	230	283	162	-3.8
Carbon Dioxide				
Coal	60,644	60,865	62,678	.4
Petroleum	195	179	179	-.9
Gas	211	254	356	6.0
Other	15	10	1	-23.3
Total	61,064	61,307	63,214	.4

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Tennessee							
Retail Sales (thousand megawatthours)							
Residential	30,199	33,367	38,752	2.8	37.8	38.4	39.4
Commercial	5,175	24,745	26,523	19.9	6.5	28.5	27.0
Industrial	43,530	27,710	31,845	-3.4	54.5	31.9	32.4
Other	928	1,095	1,113	2.0	1.2	1.3	1.1
Total	79,832	86,917	98,233	2.3	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,936	2,066	2,483	2.8	41.7	43.6	44.2
Commercial	385	1,502	1,712	18.0	8.3	31.7	30.5
Industrial	2,241	1,085	1,322	-5.7	48.3	22.9	23.5
Other	82	89	99	2.2	1.8	1.9	1.8
Total	4,644	4,742	5,616	2.1	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	6.41	6.19	6.41	*	NA	NA	NA
Commercial	7.44	6.07	6.45	-1.6	NA	NA	NA
Industrial	5.15	3.92	4.15	-2.4	NA	NA	NA
Other	8.82	8.09	8.92	.1	NA	NA	NA
Total	5.82	5.46	5.72	-.2	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Tennessee						
Number of Entities	1	71	0	19	0	91
Number of Retail Customers	45,450	2,052,094	0	798,506	0	2,896,050
Retail Sales (thousand megawatthours)	1,935	77,506	0	18,793	0	98,233
Percentage of Retail Sales	1.97	78.90	.00	19.13	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	82	4,342	0	1,192	0	5,616
Percentage of Revenue	1.46	77.31	.00	21.23	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	4.24	5.60	.00	6.34	0	5.72

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Texas		
NERC Region(s)		ERCOT/SPP/WSCC/SERC
Primary Energy Source		Gas
Net Summer Capability (megawatts)	94,488	1
Electric Utilities	38,903	2
Independent Power Producers & Combined Heat and Power	55,585	1
Net Generation (megawatthours)	385,628,543	1
Electric Utilities	149,587,269	2
Independent Power Producers & Combined Heat and Power	236,041,274	1
Emissions (thousand short tons)		
Sulfur Dioxide	629	4
Nitrogen Oxide	347	3
Carbon Dioxide	269,909	1
Sulfur Dioxide/sq. mile	2	28
Nitrogen Oxide/sq. mile	1	28
Carbon Dioxide/sq. mile	1,031	26
Utility and ESP Retail Electricity Sales (megawatthours)	320,845,849	1
Utility Retail Electricity Sales (megawatthours)	320,844,140	1
ESP Retail Electricity Sales (megawatthours)	1,709	19
Direct Use (megawatthours)	36,166,892	1
Average Retail Price (cents/kWh)	6.62	23

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Texas			
1. W A Parish	Gas, Coal	CenterPoint Energy Houston Elec	3,766
2. South Texas Project	Nuclear	CenterPoint Energy Houston Elec	2,529
3. Cedar Bayou	Gas	CenterPoint Energy Houston Elec	2,320
4. P H Robinson	Gas	CenterPoint Energy Houston Elec	2,265
5. Martin Lake	Petroleum, Coal	TXU Generation Co LP	2,250
6. Comanche Peak	Nuclear	TXU Generation Co LP	2,208
7. Monticello	Petroleum, Coal	TXU Generation Co LP	1,875
8. Sabine	Petroleum, Gas	Entergy Gulf States Inc	1,843
9. Limestone	Gas, Coal	CenterPoint Energy Houston Elec	1,646
10. Fayette Power Project	Petroleum, Coal	Lower Colorado River Authority	1,605

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Texas					
A. TXU Energy Retail Co LP	89,456,982	37,118,787	20,133,202	32,204,993	0
B. Reliant Energy Retail Serv LLC	33,941,943	20,892,300	13,049,643	0	0
C. Reliant Energy Solutions LLC	23,015,860	0	0	23,015,860	0
D. San Antonio Public Service Bd	17,000,863	7,254,629	4,943,111	2,903,812	1,899,311
E. Entergy Gulf States, Inc	14,987,342	4,981,688	3,577,511	6,172,852	255,291
Total	178,402,990	70,247,404	41,703,467	64,297,517	2,154,602
Percentage of Utility Sales	56	58	48	63	23

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Texas							
Coal	19,335	19,587	12,398	–4.8	27.1	26.7	13.1
Petroleum	29	36	4	–19.4	.0	.0	.0
Natural Gas	9,005	9,111	11,031	2.3	12.6	12.4	11.7
Dual Fired	30,065	30,623	12,244	–9.5	42.1	41.7	13.0
Nuclear	4,782	4,800	2,529	–6.8	6.7	6.5	2.7
Hydroelectric	652	686	690	.6	.9	.9	.7
Other Renewables	*	1	7	45.5	.0	.0	.0
Other	0	13	0	NM	.0	.0	.0
Total Electric Utilities	63,868	64,857	38,903	–5.4	89.4	88.3	41.2
Coal	338	340	7,798	41.7	.5	.5	8.3
Petroleum	74	70	469	22.7	.1	.1	.5
Natural Gas	5,466	6,589	25,348	18.6	7.7	9.0	26.8
Other Gases	131	156	295	9.5	.2	.2	.3
Dual Fired	1,282	1,130	18,141	34.2	1.8	1.5	19.2
Nuclear	0	0	2,208	NM	.0	.0	2.3
Hydroelectric	0	2	7	NM	.0	.0	.0
Other Renewables	218	242	1,200	20.9	.3	.3	1.3
Other	70	70	118	6.0	.1	.1	.1
Total IPP's & Combined Heat and Power	7,578	8,597	55,585	24.8	10.6	11.7	58.8
Coal	19,673	19,927	20,196	.3	27.5	27.1	21.4
Petroleum	103	105	473	18.5	.1	.1	.5
Natural Gas	14,470	15,700	36,379	10.8	20.3	21.4	38.5
Other Gases	131	156	295	9.5	.2	.2	.3
Dual Fired	31,347	31,753	30,385	–.3	43.9	43.2	32.2
Nuclear	4,782	4,800	4,737	–.1	6.7	6.5	5.0
Hydroelectric	652	687	697	.8	.9	.9	.7
Other Renewables	218	243	1,208	21.0	.3	.3	1.3
Other	70	83	118	6.0	.1	.1	.1
Total Electric Industry	71,446	73,454	94,488	3.2	100.0	100.0	100.0

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Texas							
Coal	128,266,337	135,696,240	90,259,574	-3.8	42.8	40.3	23.4
Petroleum	452,909	187,844	25,987	-27.2	.2	.1	.0
Natural Gas	104,966,938	102,163,775	39,173,483	-10.4	35.0	30.4	10.2
Nuclear	12,406,774	37,357,647	19,049,602	4.9	4.1	11.1	4.9
Hydroelectric	1,786,405	1,784,629	1,076,338	-5.5	.6	.5	.3
Other Renewables	294,877	212	2,285	-41.7	.1	.0	.0
Total Electric Utilities	**248,174,240**	**277,190,347**	**149,587,269**	**-5.5**	**82.8**	**82.4**	**38.8**
Coal	2,779,665	2,794,862	51,587,666	38.3	.9	.8	13.4
Petroleum	1,401,559	1,335,993	1,594,978	1.4	.5	.4	.4
Natural Gas	42,327,176	49,340,994	157,259,927	15.7	14.1	14.7	40.8
Other Gases	3,281,371	3,705,248	3,052,992	-.8	1.1	1.1	.8
Nuclear	0	0	16,568,402	NM	.0	.0	4.3
Hydroelectric	0	6,121	47,154	NM	.0	.0	.0
Other Renewables	1,323,574	1,541,710	3,991,150	13.0	.4	.5	1.0
Other	401,131	404,237	1,939,005	19.1	.1	.1	.5
Total IPP's & Combined Heat and Power	**51,514,476**	**59,129,165**	**236,041,274**	**18.4**	**17.2**	**17.6**	**61.2**
Coal	131,046,002	138,491,102	141,847,240	.9	43.7	41.2	36.8
Petroleum	1,854,468	1,523,837	1,620,965	-1.5	.6	.5	.4
Natural Gas	147,294,114	151,504,769	196,433,410	3.3	49.1	45.0	50.9
Other Gases	3,281,371	3,705,248	3,052,992	-.8	1.1	1.1	.8
Nuclear	12,406,774	37,357,647	35,618,004	12.4	4.1	11.1	9.2
Hydroelectric	1,786,405	1,790,750	1,123,492	-5.0	.6	.5	.3
Other Renewables	1,618,451	1,541,922	3,993,435	10.6	.5	.5	1.0
Other	401,131	404,237	1,939,005	19.1	.1	.1	.5
Total Electric Industry	**299,688,716**	**336,319,512**	**385,628,543**	**2.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Texas				
Coal (2002 cents per million Btu)	160.0	129.4	126.5	-2.6
Average heat value (Btu per pound)	7,284	7,423	7,700	.6
Average sulfur Content(percent)	.7	.7	.7	-1.1
Petroleum (2002 cents per million Btu)	199.1	351.1	199.6	*
Average heat value (Btu per gallon)	112,765	114,810	138,090	2.3
Average sulfur Content(percent)	1.9	3.5	3.9	8.6
Gas (2002 cents per million Btu)	268.4	270.6	331.7	2.4
Average heat value (Btu per cubic foot)	1,026	1,023	1,019	-.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Texas				
Sulfur Dioxide				
Coal	601	712	612	0.2
Petroleum	49	39	6	-21.0
Gas	*	*	0	NM
Other	4	6	6	3.5
Total	655	757	623	-.5
Nitrogen Oxide				
Coal	472	280	187	-9.8
Petroleum	4	3	3	-1.8
Gas	174	191	151	-1.6
Other	3	4	6	6.4
Total	653	478	347	-6.8
Carbon Dioxide				
Coal	145,253	154,993	164,436	1.4
Petroleum	2,296	1,921	2,473	.8
Gas	85,190	87,396	103,000	2.1
Total	232,738	244,310	269,909	1.7

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Texas							
Retail Sales (thousand megawatthours)							
Residential	87,686	101,094	121,435	3.7	35.1	35.3	37.8
Commercial	64,331	72,042	87,746	3.5	25.7	25.1	27.3
Industrial	86,933	100,429	102,251	1.8	34.8	35.0	31.9
Other	11,134	13,138	9,414	-1.8	4.4	4.6	2.9
Total	250,084	286,704	320,846	2.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	7,817	8,123	9,778	2.5	43.9	44.7	46.0
Commercial	4,976	4,987	6,095	2.3	27.9	27.4	28.7
Industrial	4,185	4,184	4,761	1.4	23.5	23.0	22.4
Other	828	871	616	-3.2	4.6	4.8	2.9
Total	17,805	18,165	21,251	2.0	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.91	8.04	8.05	-1.1	NA	NA	NA
Commercial	7.73	6.92	6.95	-1.2	NA	NA	NA
Industrial	4.81	4.17	4.66	-.4	NA	NA	NA
Other	7.44	6.63	6.55	-1.4	NA	NA	NA
Total	7.12	6.34	6.62	-.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Texas						
Number of Entities	6	118	0	60	1	185
Number of Retail Customers	332,048	8,438,624	0	1,496,304	1	10,266,977
Retail Sales (thousand megawatthours)	5,625	285,782	0	29,437	2	320,846
Percentage of Retail Sales	1.75	89.07	.00	9.17	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	544	18,580	0	2,126	0	21,251
Percentage of Revenue	2.56	87.43	.00	10.00	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	9.68	6.50	.00	7.22	0	6.62

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Utah		
NERC Region(s)		WSCC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	5,752	39
Electric Utilities	5,573	31
Independent Power Producers & Combined Heat and Power	179	47
Net Generation (megawatthours)	36,608,003	35
Electric Utilities	36,071,946	29
Independent Power Producers & Combined Heat and Power	536,057	46
Emissions (thousand short tons)		
Sulfur Dioxide	51	34
Nitrogen Oxide	77	30
Carbon Dioxide	37,173	28
Sulfur Dioxide/sq. mile	1	39
Nitrogen Oxide/sq. mile	1	35
Carbon Dioxide/sq. mile	452	37
Utility and ESP Retail Electricity Sales (megawatthours)	23,267,188	37
Utility Retail Electricity Sales (megawatthours)	23,267,188	37
Direct Use (megawatthours)	400,012	33
Average Retail Price (cents/kWh)	5.39	47

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Utah			
1. Intermountain Power P	Petroleum, Coal	Los Angeles City of	1,640
2. Hunter	Petroleum, Coal	PacifiCorp	1,320
3. Huntington	Petroleum, Coal	PacifiCorp	895
4. Bonanza	Petroleum, Coal	Deseret Generation & Tran Coop	425
5. Gadsby	Gas	PacifiCorp	349
6. West Valley Generatio	Gas	PacifiCorp	185
7. Carbon	Petroleum, Coal	PacifiCorp	172
8. Murray Turbine	Gas	Murray City of	159
9. Flaming Gorge	Hydro	U S Bureau of Reclamation	152
10. Desert Power LP	Gas	Desert Power LP	68

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Utah					
A. PacifiCorp	18,719,865	5,250,614	6,517,053	6,403,497	548,701
B. Provo City Corporation	706,560	213,901	367,429	120,392	4,838
C. St George Dept Water & Power	467,707	210,792	240,872	0	16,043
D. Logan City Light & Power	388,401	83,846	153,204	86,021	65,330
E. Murray City Power Department	365,004	110,967	244,972	0	9,065
Total	20,647,537	5,870,120	7,523,530	6,609,910	643,977
Percentage of Utility Sales	89	85	89	94	76

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Utah							
Coal	4,271	4,318	4,461	0.5	86.3	85.1	77.6
Petroleum	25	33	28	1.0	.5	.7	.5
Natural Gas	173	238	719	17.1	3.5	4.7	12.5
Dual Fired	54	57	81	4.5	1.1	1.1	1.4
Hydroelectric	253	263	252	.0	5.1	5.2	4.4
Other Renewables	35	35	33	−.8	.7	.7	.6
Total Electric Utilities	**4,812**	**4,945**	**5,573**	**1.6**	**97.2**	**97.4**	**96.9**
Coal	54	54	101	7.1	1.1	1.1	1.8
Petroleum	1	10	3	10.3	.0	.2	.1
Natural Gas	2	11	72	49.7	.0	.2	1.2
Other Gases	48	48	0	NM	1.0	.9	.0
Dual Fired	20	3	0	NM	.4	.1	.0
Hydroelectric	10	4	2	−15.7	.2	.1	.0
Other Renewables	0	0	1	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**136**	**130**	**179**	**3.1**	**2.8**	**2.6**	**3.1**
Coal	4,325	4,372	4,562	.6	87.4	86.2	79.3
Petroleum	27	43	31	1.6	.5	.9	.5
Natural Gas	175	249	791	18.2	3.5	4.9	13.7
Other Gases	48	48	0	NM	1.0	.9	.0
Dual Fired	75	60	81	.8	1.5	1.2	1.4
Hydroelectric	263	267	254	−.4	5.3	5.3	4.4
Other Renewables	35	35	34	−.3	.7	.7	.6
Total Electric Industry	**4,948**	**5,075**	**5,752**	**1.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Utah							
Coal	31,919,309	32,143,936	34,080,979	0.7	93.7	92.6	93.1
Petroleum	32,104	28,836	53,469	5.8	.1	.1	.1
Natural Gas	542,969	297,457	1,268,326	9.9	1.6	.9	3.5
Hydroelectric	818,409	1,330,578	451,521	-6.4	2.4	3.8	1.2
Other Renewables	148,148	168,518	217,651	4.4	.4	.5	.6
Total Electric Utilities	**33,460,939**	**33,969,325**	**36,071,946**	**.8**	**98.2**	**97.9**	**98.5**
Coal	206,484	400,067	406,744	7.8	.6	1.2	1.1
Petroleum	4,482	18,112	50	-39.3	.0	.1	.0
Natural Gas	63,130	30,108	111,855	6.6	.2	.1	.3
Other Gases	281,457	281,018	0	NM	.8	.8	.0
Hydroelectric	41,611	13,583	6,211	-19.0	.1	.0	.0
Other Renewables	0	0	11,197	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**597,163**	**742,888**	**536,057**	**-1.2**	**1.8**	**2.1**	**1.5**
Coal	32,125,793	32,544,003	34,487,723	.8	94.3	93.8	94.2
Petroleum	36,586	46,948	53,519	4.3	.1	.1	.1
Natural Gas	606,099	327,565	1,380,181	9.6	1.8	.9	3.8
Other Gases	281,457	281,018	0	NM	.8	.8	.0
Hydroelectric	860,020	1,344,161	457,732	-6.8	2.5	3.9	1.3
Other Renewables	148,148	168,518	228,848	5.0	.4	.5	.6
Total Electric Industry	**34,058,102**	**34,712,213**	**36,608,003**	**.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Utah				
Coal (2002 cents per million Btu)	132.6	114.4	97.5	-3.4
Average heat value (Btu per pound)	11,489	11,330	11,259	-.2
Average sulfur Content(percent)	.5	.5	.5	1.6
Petroleum (2002 cents per million Btu)	601.0	599.8	556.4	-.8
Average heat value (Btu per gallon)	139,596	139,821	140,364	.1
Average sulfur Content(percent)	.0	.0	.3	NM
Gas (2002 cents per million Btu)	242.6	208.6	423.0	6.4
Average heat value (Btu per cubic foot)	1,063	1,032	1,006	-.6

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Utah				
Sulfur Dioxide				
Coal	33	34	51	5.0
Petroleum	*	*	*	13.0
Gas	*	*	0	NM
Other	0	0	0	NM
Total	33	34	51	5.0
Nitrogen Oxide				
Coal	99	73	76	-2.9
Petroleum	*	*	*	-7.0
Gas	7	6	1	-19.1
Other	0	0	*	NM
Total	105	79	77	-3.4
Carbon Dioxide				
Coal	33,832	34,381	36,181	.8
Petroleum	30	37	45	4.7
Gas	564	400	944	5.9
Other	0	0	3	NM
Total	34,426	34,818	37,173	.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Utah							
Retail Sales (thousand megawatthours)							
Residential	4,726	5,661	6,938	4.4	28.0	27.8	29.8
Commercial	5,020	6,469	8,463	6.0	29.8	31.8	36.4
Industrial	6,221	7,430	7,019	1.3	36.9	36.5	30.2
Other	900	815	846	-.7	5.3	4.0	3.6
Total	16,867	20,376	23,267	3.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	361	401	471	3.0	36.0	37.0	37.6
Commercial	333	380	474	4.0	33.3	35.1	37.8
Industrial	262	266	269	.3	26.1	24.6	21.5
Other	45	36	40	-1.4	4.5	3.4	3.2
Total	1,001	1,084	1,255	2.5	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.63	7.08	6.79	-1.3	NA	NA	NA
Commercial	6.64	5.88	5.60	-1.9	NA	NA	NA
Industrial	4.21	3.58	3.84	-1.0	NA	NA	NA
Other	5.00	4.46	4.69	-.7	NA	NA	NA
Total	5.93	5.32	5.39	-1.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Utah						
Number of Entities	0	50	0	2	0	52
Number of Retail Customers	0	902,374	0	2,164	0	904,538
Retail Sales (thousand megawatthours)	0	23,231	0	36	0	23,267
Percentage of Retail Sales	.00	99.84	.00	.16	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	0	1,252	0	2	0	1,255
Percentage of Revenue	.00	99.81	.00	.19	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	.00	5.39	.00	6.46	0	5.39

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Vermont		
NERC Region(s)		NPCC
Primary Energy Source		Nuclear
Net Summer Capability (megawatts)	994	50
Electric Utilities	261	45
Independent Power Producers & Combined Heat and Power	733	41
Net Generation (megawatthours)	5,456,190	50
Electric Utilities	2,971,224	43
Independent Power Producers & Combined Heat and Power	2,484,966	39
Emissions (thousand short tons)		
Sulfur Dioxide	0	51
Nitrogen Oxide	0	51
Carbon Dioxide	17	51
Sulfur Dioxide/sq. mile	0	51
Nitrogen Oxide/sq. mile	0	49
Carbon Dioxide/sq. mile	2	51
Utility and ESP Retail Electricity Sales (megawatthours)	5,629,263	50
Utility Retail Electricity Sales (megawatthours)	5,629,263	49
Direct Use (megawatthours)	–51,975	45
Average Retail Price (cents/kWh)	10.87	5

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Vermont			
1. Vermont Yankee	Nuclear	Entergy Nuclear Vermont Yankee	506
2. J C McNeil	Petroleum, Gas, Other	Burlington City of	52
3. Bellows Falls	Hydro	U S Gen New England Inc	49
4. Wilder	Hydro	U S Gen New England Inc	41
5. Harriman	Hydro	U S Gen New England Inc	41
6. Berlin 5	Petroleum	Green Mountain Power Corp	36
7. Sheldon Springs Hydro	Hydro	Missisquoi Associates	24
8. Ryegate Power Station	Other	Ryegate Associates	20
9. Burlington GT	Petroleum	Burlington City of	20
10. Vernon	Hydro	U S Gen New England Inc	19

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Vermont					
A. Central Vermont Pub Serv Corp	2,186,344	915,031	858,537	407,335	5,441
B. Green Mountain Power Corp	1,948,148	553,294	723,641	661,480	9,733
C. City of Burlington	340,502	91,615	185,343	60,498	3,046
D. Citizens Communications Co	302,182	115,456	73,288	103,514	9,924
E. Vermont Marble Pwr Div of OMYA	217,349	6,076	3,338	207,837	98
Total	4,994,525	1,681,472	1,844,147	1,440,664	28,242
Percentage of Utility Sales	89	82	95	91	63

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Vermont							
Petroleum	120	119	107	-1.3	10.3	10.2	10.7
Nuclear	496	496	0	NM	42.6	42.5	.0
Hydroelectric	430	423	102	-14.8	36.9	36.3	10.3
Other Renewables	47	56	53	1.2	4.1	4.8	5.3
Total Electric Utilities	**1,094**	**1,094**	**261**	**-14.7**	**93.9**	**93.8**	**26.3**
Nuclear	0	0	506	NM	.0	.0	50.9
Hydroelectric	47	48	203	17.6	4.1	4.1	20.4
Other Renewables	24	24	24	-.1	2.0	2.0	2.4
Total IPP's & Combined Heat and Power	**71**	**72**	**733**	**29.6**	**6.1**	**6.2**	**73.7**
Petroleum	120	119	107	-1.3	10.3	10.2	10.7
Nuclear	496	496	506	.2	42.6	42.5	50.9
Hydroelectric	477	472	305	-4.9	41.0	40.4	30.7
Other Renewables	71	80	76	.8	6.1	6.9	7.7
Total Electric Industry	**1,165**	**1,167**	**994**	**-1.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Vermont							
Petroleum	4,805	9,816	9,406	7.7	0.1	0.2	0.2
Natural Gas	20,558	93	3,275	-18.5	.4	.0	.1
Nuclear	3,372,148	4,266,866	2,367,209	-3.9	72.6	75.1	43.4
Hydroelectric	838,619	896,312	404,227	-7.8	18.1	15.8	7.4
Other Renewables	64,407	150,345	187,107	12.6	1.4	2.6	3.4
Total Electric Utilities	**4,300,537**	**5,323,432**	**2,971,224**	**-4.0**	**92.6**	**93.7**	**54.5**
Petroleum	224	1,390	0	NM	.0	.0	.0
Nuclear	0	0	1,595,407	NM	.0	.0	29.2
Hydroelectric	142,667	171,129	710,695	19.5	3.1	3.0	13.0
Other Renewables	200,337	184,586	178,864	-1.3	4.3	3.2	3.3
Total IPP's & Combined Heat and Power	**343,228**	**357,106**	**2,484,966**	**24.6**	**7.4**	**6.3**	**45.5**
Petroleum	5,029	11,206	9,406	7.2	.1	.2	.2
Natural Gas	20,558	93	3,275	-18.5	.4	.0	.1
Nuclear	3,372,148	4,266,866	3,962,616	1.8	72.6	75.1	72.6
Hydroelectric	981,286	1,067,441	1,114,922	1.4	21.1	18.8	20.4
Other Renewables	264,744	334,931	365,971	3.7	5.7	5.9	6.7
Total Electric Industry	**4,643,765**	**5,680,538**	**5,456,190**	**1.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Vermont				
Petroleum (2002 cents per million Btu)	540.8	466.1	0.0	NM
Average heat value (Btu per gallon)	134,183	136,720	137,760	0.3
Gas (2002 cents per million Btu)	224.8	320.8	383.7	6.1
Average heat value (Btu per cubic foot)	998	1,012	1,018	.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Vermont				
Sulfur Dioxide				
Petroleum	0	0	0	NM
Other	*	0	*	0.0
Total	*	*	*	-2.0
Gas	*	*	0	NM
Other	*	*	*	3.0
Total	*	*	*	1.7
Nitrogen Oxide				
Petroleum	8	16	15	6.9
Gas	16	2	2	-19.7
Total	24	18	17	-3.7

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Vermont							
Retail Sales (thousand megawatthours)							
Residential	1,971	1,992	2,047	0.4	39.3	37.5	36.4
Commercial	1,570	1,675	1,946	2.4	31.3	31.5	34.6
Industrial	1,431	1,561	1,592	1.2	28.5	29.4	28.3
Other	44	84	45	.3	.9	1.6	.8
Total	5,016	5,312	5,629	1.3	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	216	234	262	2.1	42.8	43.4	42.7
Commercial	163	178	216	3.2	32.3	32.9	35.3
Industrial	120	119	126	.6	23.7	22.1	20.5
Other	7	8	9	3.1	1.3	1.5	1.4
Total	505	540	612	2.2	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	10.96	11.77	12.78	1.7	NA	NA	NA
Commercial	10.37	10.61	11.10	.8	NA	NA	NA
Industrial	8.35	7.65	7.90	–.6	NA	NA	NA
Other	15.04	9.82	19.26	2.8	NA	NA	NA
Total	10.07	10.16	10.87	.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Vermont						
Number of Entities	5	16	0	2	0	23
Number of Retail Customers	235,844	72,833	0	25,731	0	334,408
Retail Sales (thousand megawatthours)	4,359	1,064	0	207	0	5,629
Percentage of Retail Sales	77.43	18.89	.00	3.68	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	474	110	0	28	0	612
Percentage of Revenue	77.41	17.98	.00	4.62	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	10.87	10.34	.00	13.63	0	10.87

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Virginia		
NERC Region(s)		ECAR/SERC/MAAC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	20,205	17
Electric Utilities	15,818	14
Independent Power Producers & Combined Heat and Power	4,387	17
Net Generation (megawatthours)	75,005,651	21
Electric Utilities	62,880,125	17
Independent Power Producers & Combined Heat and Power	12,125,526	20
Emissions (thousand short tons)		
Sulfur Dioxide	251	15
Nitrogen Oxide	103	17
Carbon Dioxide	46,487	22
Sulfur Dioxide/sq. mile	6	18
Nitrogen Oxide/sq. mile	3	20
Carbon Dioxide/sq. mile	1,174	24
Utility and ESP Retail Electricity Sales (megawatthours)	100,540,736	12
Utility Retail Electricity Sales (megawatthours)	100,305,309	12
ESP Retail Electricity Sales (megawatthours)	235,427	17
Direct Use (megawatthours)	1,862,173	20
Average Retail Price (cents/kWh)	6.23	30

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Virginia			
1. Bath County	Hydro	Virginia Electric & Power Co	2,400
2. North Anna	Nuclear	Virginia Electric & Power Co	1,843
3. Chesterfield	Petroleum, Gas, Coal	Virginia Electric & Power Co	1,631
4. Surry	Nuclear	Virginia Electric & Power Co	1,625
5. Possum Point	Petroleum, Coal	Virginia Electric & Power Co	1,186
6. Yorktown	Gas, Coal, Petroleum	Virginia Electric & Power Co	1,144
7. Clover	Petroleum, Coal	Virginia Electric & Power Co	882
8. Doswell Combined Cycl	Petroleum, Gas	Doswell Ltd Partnership	820
9. Chesapeake	Petroleum, Coal	Virginia Electric & Power Co	739
10. Clinch River	Petroleum, Coal	Appalachian Power Co	690

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Virginia					
A. Virginia Electric & Power Co.	67,616,714	25,526,415	23,497,176	9,211,471	9,381,652
B. Appalachian Power Company	15,507,106	6,061,620	3,043,817	5,667,007	734,662
C. The Potomac Edison Company	2,674,073	1,075,661	565,932	1,028,331	4,149
D. Northern Virginia Elec Coop	2,533,321	1,575,816	653,549	300,992	2,964
E. Rappahannock Electric Coop	2,253,515	1,152,634	101,685	993,406	5,790
Total	90,584,729	35,392,146	27,862,159	17,201,207	10,129,217
Percentage of Utility Sales	90	88	93	88	95

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Virginia							
Coal	4,217	5,099	4,789	1.4	24.8	27.2	23.7
Petroleum	1,204	2,025	1,917	5.3	7.1	10.8	9.5
Natural Gas	593	545	1,244	8.6	3.5	2.9	6.2
Dual Fired	1,582	1,146	1,019	–4.8	9.3	6.1	5.0
Nuclear	3,349	3,392	3,467	.4	19.7	18.1	17.2
Hydroelectric	3,109	3,085	3,383	.9	18.3	16.5	16.7
Other Renewables	*	*	0	NM	.0	.0	.0
Total Electric Utilities	**14,054**	**15,291**	**15,818**	**1.3**	**82.5**	**81.6**	**78.3**
Coal	895	1,150	1,328	4.5	5.3	6.1	6.6
Petroleum	5	8	358	61.2	.0	.0	1.8
Natural Gas	79	99	434	20.9	.5	.5	2.1
Dual Fired	1,475	1,547	1,663	1.3	8.7	8.3	8.2
Hydroelectric	22	21	20	–1.2	.1	.1	.1
Other Renewables	508	614	584	1.5	3.0	3.3	2.9
Total IPP's & Combined Heat and Power	**2,983**	**3,439**	**4,387**	**4.4**	**17.5**	**18.4**	**21.7**
Coal	5,112	6,249	6,117	2.0	30.0	33.4	30.3
Petroleum	1,209	2,034	2,275	7.3	7.1	10.9	11.3
Natural Gas	672	644	1,678	10.7	3.9	3.4	8.3
Dual Fired	3,057	2,693	2,682	–1.4	17.9	14.4	13.3
Nuclear	3,349	3,392	3,467	.4	19.7	18.1	17.2
Hydroelectric	3,131	3,106	3,402	.9	18.4	16.6	16.8
Other Renewables	508	614	584	1.5	3.0	3.3	2.9
Total Electric Industry	**17,037**	**18,731**	**20,205**	**1.9**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Virginia							
Coal	24,722,481	29,676,411	31,099,307	2.6	40.4	43.3	41.5
Petroleum	2,157,896	857,789	3,454,714	5.4	3.5	1.3	4.6
Natural Gas	2,139,635	1,291,954	2,128,402	–.1	3.5	1.9	2.8
Nuclear	22,688,763	27,084,059	27,346,163	2.1	37.0	39.5	36.5
Hydroelectric	473,123	75,778	–1,148,461	NM	.8	.1	-1.5
Other Renewables	8	0	0	NM	.0	.0	.0
Total Electric Utilities	**52,181,906**	**58,985,991**	**62,880,125**	**2.1**	**85.2**	**86.1**	**83.8**
Coal	4,687,521	4,483,521	6,983,074	4.5	7.7	6.5	9.3
Petroleum	342,913	1,912,253	337,890	–.2	.6	2.8	.5
Natural Gas	2,238,431	588,096	2,258,525	.1	3.7	.9	3.0
Other Gases	0	67	0	NM	.0	.0	.0
Hydroelectric	66,095	80,707	27,842	–9.2	.1	.1	.0
Other Renewables	1,726,645	2,464,699	2,518,195	4.3	2.8	3.6	3.4
Total IPP's & Combined Heat and Power	**9,061,605**	**9,529,343**	**12,125,526**	**3.3**	**14.8**	**13.9**	**16.2**
Coal	29,410,002	34,159,932	38,082,381	2.9	48.0	49.9	50.8
Petroleum	2,500,809	2,770,042	3,792,604	4.7	4.1	4.0	5.1
Natural Gas	4,378,066	1,880,050	4,386,927	.0	7.1	2.7	5.8
Other Gases	0	67	0	NM	.0	.0	.0
Nuclear	22,688,763	27,084,059	27,346,163	2.1	37.0	39.5	36.5
Hydroelectric	539,218	156,485	–1,120,619	NM	.9	.2	–1.5
Other Renewables	1,726,653	2,464,699	2,518,195	4.3	2.8	3.6	3.4
Total Electric Industry	**61,243,511**	**68,515,334**	**75,005,651**	**2.3**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Virginia				
Coal (2002 cents per million Btu)	163.4	143.2	169.2	0.4
Average heat value (Btu per pound)	12,817	12,554	12,757	*
Average sulfur Content(percent)	1.0	1.0	1.2	1.7
Petroleum (2002 cents per million Btu)	237.1	289.7	380.3	5.4
Average heat value (Btu per gallon)	150,319	148,219	148,645	–.1
Average sulfur Content(percent)	1.0	1.1	1.0	.0
Gas (2002 cents per million Btu)	310.5	281.6	413.4	3.2
Average heat value (Btu per cubic foot)	1,038	1,069	1,019	–.2

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Virginia				
Sulfur Dioxide				
Coal	207	232	230	1.2
Petroleum	12	11	19	5.3
Gas	*	0	0	NM
Other	3	3	3	–.5
Total	221	246	251	1.4
Nitrogen Oxide				
Coal	97	122	95	–.2
Petroleum	2	2	3	3.3
Gas	3	2	2	–4.8
Other	3	3	3	.9
Total	105	129	103	–.2
Carbon Dioxide				
Coal	30,126	34,840	40,762	3.4
Petroleum	2,093	1,901	3,121	4.5
Gas	2,341	1,055	2,367	.1
Other	155	183	237	4.9
Total	34,715	37,978	46,487	3.3

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Virginia							
Retail Sales (thousand megawatthours)							
Residential	32,472	33,923	40,389	2.4	39.9	38.8	40.2
Commercial	22,727	24,905	29,993	3.1	27.9	28.5	29.8
Industrial	17,390	19,249	19,489	1.3	21.4	22.0	19.4
Other	8,783	9,342	10,669	2.2	10.8	10.7	10.6
Total	81,372	87,420	100,541	2.4	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	2,739	2,701	3,146	1.5	48.5	49.0	50.2
Commercial	1,554	1,528	1,761	1.4	27.5	27.7	28.1
Industrial	812	792	805	–.1	14.4	14.4	12.9
Other	544	494	549	.1	9.6	9.0	8.8
Total	5,650	5,514	6,262	1.1	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	8.43	7.96	7.79	–.9	NA	NA	NA
Commercial	6.84	6.13	5.87	–1.7	NA	NA	NA
Industrial	4.67	4.11	4.13	–1.3	NA	NA	NA
Other	6.20	5.29	5.15	–2.0	NA	NA	NA
Total	6.94	6.31	6.23	–1.2	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Virginia						
Number of Entities	1	24	0	10	2	37
Number of Retail Customers	489,192	2,397,099	0	351,884	22,824	3,260,999
Retail Sales (thousand megawatthours)	15,507	77,199	0	7,599	235	100,541
Percentage of Retail Sales	15.42	76.78	.00	7.56	.23	100.00
Revenue from Retail Sales (million 2002 dollars)	689	4,918	0	645	10	6,262
Percentage of Revenue	11.00	78.54	.00	10.29	.17	100.00
Revenue per Kilowatthour (2002 cents/kWh)	4.44	6.37	.00	8.48	0	6.23

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Washington		
NERC Region(s)		WSCC
Primary Energy Source		Hydro
Net Summer Capability (megawatts)	27,112	10
Electric Utilities	24,141	6
Independent Power Producers & Combined Heat and Power	2,971	25
Net Generation (megawatthours)	102,765,048	13
Electric Utilities	88,568,483	11
Independent Power Producers & Combined Heat and Power	14,196,565	17
Emissions (thousand short tons)		
Sulfur Dioxide	21	42
Nitrogen Oxide	21	39
Carbon Dioxide	12,912	39
Sulfur Dioxide/sq. mile	0	44
Nitrogen Oxide/sq. mile	0	44
Carbon Dioxide/sq. mile	194	45
Utility and ESP Retail Electricity Sales (megawatthours)	76,491,883	18
Utility Retail Electricity Sales (megawatthours)	75,403,856	18
ESP Retail Electricity Sales (megawatthours)	1,088,027	13
Direct Use (megawatthours)	−1,894,139	51
Average Retail Price (cents/kWh)	5.80	38

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Washington			
1. Grand Coulee	Hydro	U S Bureau of Reclamation	7,079
2. Chief Joseph	Hydro	USCE-North Pacific Division	2,337
3. Transalta Centralia G	Petroleum, Gas, Coal	TransAlta Centralia Gen LLC	1,661
4. Rocky Reach	Hydro	PUD No 1 of Chelan County	1,279
5. Columbia Generating S	Nuclear	Energy Northwest	1,108
6. Boundary	Hydro	Seattle City of	1,050
7. Wanapum	Hydro	PUD No 2 of Grant County	969
8. Little Goose	Hydro	USCE-North Pacific Division	932
9. Lower Monumental	Hydro	USCE-North Pacific Division	932
10. Lower Granite	Hydro	USCE-North Pacific Division	932

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Washington					
A. Puget Sound Energy, Inc	19,253,824	9,801,319	7,974,498	1,395,544	82,463
B. Seattle City Light	8,923,130	3,073,673	3,845,912	1,197,613	805,932
C. PUD No 1 of Snohomish County	6,193,672	3,233,187	2,103,795	832,995	23,695
D. Avista Corporation	4,997,514	2,192,350	1,955,438	819,602	30,124
E. Tacoma Power	4,535,202	1,792,236	321,567	1,791,618	629,781
Total	43,903,342	20,092,765	16,201,210	6,037,372	1,571,995
Percentage of Utility Sales	57	63	67	36	49

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Washington							
Coal	1,390	1,390	0	NM	5.6	5.3	0.0
Petroleum	173	62	40	−15.2	.7	.2	.1
Natural Gas	0	248	303	NM	.0	.9	1.1
Dual Fired	590	590	843	4.1	2.4	2.2	3.1
Nuclear	1,100	1,170	1,108	.1	4.4	4.5	4.1
Hydroelectric	20,960	21,731	21,706	.4	83.9	82.8	80.1
Other Renewables	46	83	142	13.3	.2	.3	.5
Total Electric Utilities	**24,259**	**25,273**	**24,141**	**−.1**	**97.1**	**96.3**	**89.0**
Coal	2	2	1,407	108.9	.0	.0	5.2
Natural Gas	335	480	937	12.1	1.3	1.8	3.5
Dual Fired	146	256	177	2.1	.6	1.0	.7
Hydroelectric	90	100	72	−2.4	.4	.4	.3
Other Renewables	161	142	378	9.9	.6	.5	1.4
Total IPP's & Combined Heat and Power	**734**	**979**	**2,971**	**16.8**	**2.9**	**3.7**	**11.0**
Coal	1,392	1,392	1,407	.1	5.6	5.3	5.2
Petroleum	173	62	40	−15.2	.7	.2	.1
Natural Gas	335	728	1,240	15.6	1.3	2.8	4.6
Dual Fired	736	846	1,020	3.7	2.9	3.2	3.8
Nuclear	1,100	1,170	1,108	.1	4.4	4.5	4.1
Hydroelectric	21,049	21,830	21,778	.4	84.2	83.2	80.3
Other Renewables	207	225	519	10.7	.8	.9	1.9
Total Electric Industry	**24,993**	**26,253**	**27,112**	**.9**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Washington							
Coal	8,803,840	6,965,990	0	NM	10.0	5.7	0.0
Petroleum	32,118	16,297	6,172	−16.7	.0	.0	.0
Natural Gas	422,218	228,754	1,084,370	11.0	.5	.2	1.1
Nuclear	7,134,966	6,244,135	9,048,475	2.7	8.1	5.1	8.8
Hydroelectric	66,982,839	103,644,592	77,828,754	1.7	76.1	84.9	75.7
Other Renewables	395,167	353,256	600,712	4.8	.4	.3	.6
Total Electric Utilities	**83,771,148**	**117,453,024**	**88,568,483**	**.6**	**95.2**	**96.2**	**86.2**
Coal	31,239	24,530	8,660,805	86.8	.0	.0	8.4
Petroleum	27,316	212,292	67,130	10.5	.0	.2	.1
Natural Gas	2,775,728	2,732,907	3,634,941	3.0	3.2	2.2	3.5
Other Gases	222,852	290,495	312,638	3.8	.3	.2	.3
Hydroelectric	329,544	525,959	333,378	.1	.4	.4	.3
Other Renewables	837,943	886,961	1,187,673	4.0	1.0	.7	1.2
Other	7	0	0	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**4,224,628**	**4,673,143**	**14,196,565**	**14.4**	**4.8**	**3.8**	**13.8**
Coal	8,835,079	6,990,520	8,660,805	−.2	10.0	5.7	8.4
Petroleum	59,434	228,589	73,302	2.4	.1	.2	.1
Natural Gas	3,197,946	2,961,661	4,719,311	4.4	3.6	2.4	4.6
Other Gases	222,852	290,495	312,638	3.8	.3	.2	.3
Nuclear	7,134,966	6,244,135	9,048,475	2.7	8.1	5.1	8.8
Hydroelectric	67,312,383	104,170,551	78,162,132	1.7	76.5	85.3	76.1
Other Renewables	1,233,110	1,240,217	1,788,385	4.2	1.4	1.0	1.7
Other	7	0	0	NM	.0	.0	.0
Total Electric Industry	**87,995,776**	**122,126,167**	**102,765,048**	**1.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Washington				
Coal (2002 cents per million Btu)	151.6	167.1	146.1	−0.4
Average heat value (Btu per pound)	8,125	8,043	8,052	−.1
Average sulfur Content(percent)	.7	.6	1.0	4.0
Petroleum (2002 cents per million Btu)	522.7	513.0	241.1	−8.2
Average heat value (Btu per gallon)	139,936	139,944	146,121	.5
Average sulfur Content(percent)	.0	.0	.3	NM
Gas (2002 cents per million Btu)	419.2	4644.9	354.2	−1.8
Average heat value (Btu per cubic foot)	1,050	1,048	1,026	−.3

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Washington				
Sulfur Dioxide				
Coal	71	65	19	-13.4
Petroleum	*	1	*	8.9
Gas	*	*	*	2.8
Other	2	2	2	-2.6
Total	73	68	21	-12.7
Nitrogen Oxide				
Coal	43	16	16	-10.7
Petroleum	*	*	*	.2
Gas	2	3	4	10.8
Other	1	1	1	-.3
Total	46	21	21	-8.2
Carbon Dioxide				
Coal	9,920	8,323	10,371	.5
Petroleum	69	203	74	.8
Gas	1,785	1,877	2,433	3.5
Other	39	36	34	-1.5
Total	11,812	10,439	12,912	1.0

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Washington							
Retail Sales (thousand megawatthours)							
Residential	30,932	31,749	32,066	0.4	34.2	35.9	41.9
Commercial	19,531	21,583	24,310	2.5	21.6	24.4	31.8
Industrial	36,563	31,348	16,880	-8.2	40.4	35.5	22.1
Other	3,447	3,627	3,237	-.7	3.8	4.1	4.2
Total	90,473	88,306	76,492	-1.8	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,584	1,616	2,018	2.7	43.1	44.1	45.5
Commercial	979	1,063	1,485	4.7	26.6	29.0	33.5
Industrial	976	833	770	-2.6	26.5	22.8	17.4
Other	136	151	160	1.8	3.7	4.1	3.6
Total	3,674	3,663	4,433	2.1	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	5.12	5.09	6.29	2.3	NA	NA	NA
Commercial	5.01	4.93	6.11	2.2	NA	NA	NA
Industrial	2.67	2.66	4.56	6.1	NA	NA	NA
Other	3.94	4.17	4.94	2.6	NA	NA	NA
Total	4.06	4.15	5.80	4.0	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Washington						
Number of Entities	1	49	0	13	3	66
Number of Retail Customers	950,043	1,780,677	0	107,196	6	2,837,922
Retail Sales (thousand megawatthours)	19,254	53,531	0	2,619	1,088	76,492
Percentage of Retail Sales	25.17	69.98	.00	3.42	1.42	100.00
Revenue from Retail Sales (million 2002 dollars)	1,260	2,915	0	148	110	4,433
Percentage of Revenue	28.43	65.76	.00	3.34	2.47	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.55	5.45	.00	5.65	0	5.80

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
West Virginia		
NERC Region(s)		ECAR
Primary Energy Source		Coal
Net Summer Capability (megawatts)	16,180	23
Electric Utilities	10,166	24
Independent Power Producers & Combined Heat and Power	6,014	14
Net Generation (megawatthours)	94,761,752	17
Electric Utilities	63,341,620	16
Independent Power Producers & Combined Heat and Power	31,420,132	10
Emissions (thousand short tons)		
Sulfur Dioxide	523	6
Nitrogen Oxide	243	5
Carbon Dioxide	95,170	8
Sulfur Dioxide/sq. mile	22	4
Nitrogen Oxide/sq. mile	10	3
Carbon Dioxide/sq. mile	3,951	2
Utility and ESP Retail Electricity Sales (megawatthours)	28,463,122	35
Utility Retail Electricity Sales (megawatthours)	28,463,122	35
Direct Use (megawatthours)	-53,279	46
Average Retail Price (cents/kWh)	5.11	49

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
West Virginia			
1. John E Amos	Petroleum, Coal	Appalachian Power Co	2,900
2. Harrison Power Statio	Petroleum, Gas, Coal	Allegheny Energy Supply Co LLC	1,933
3. Mitchell	Petroleum, Coal	Ohio Power Co	1,600
4. Mt Storm	Petroleum, Coal	Virginia Electric & Power Co	1,581
5. Mountaineer	Petroleum, Coal	Appalachian Power Co	1,300
6. Pleasants Power Stati	Petroleum, Gas, Coal	Allegheny Energy Supply Co LLC	1,278
7. Fort Martin Power Sta	Petroleum, Coal	Allegheny Energy Supply Co LLC	1,107
8. Philip Sporn	Petroleum, Coal	Central Operating Co	1,020
9. Kammer	Petroleum, Coal	Ohio Power Co	600
10. Ceredo Generating Sta	Gas	Orion Power Operating Services	457

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
West Virginia					
A. Appalachian Power Company	13,436,666	5,376,575	3,580,274	4,444,482	35,335
B. Monongahela Power Company	10,264,625	3,140,813	2,351,449	4,748,799	23,564
C. The Potomac Edison Company	2,755,273	1,348,265	653,300	749,232	4,476
D. Wheeling Power Company	1,747,850	412,183	384,006	945,546	6,115
E. Harrison Rural Elec Assn, Inc	58,830	49,060	4,330	2,990	2,450
Total	28,263,244	10,326,896	6,973,359	10,891,049	71,940
Percentage of Utility Sales	99	99	99	100	92

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
West Virginia							
Coal	14,328	14,381	10,108	-3.8	94.8	95.6	62.5
Petroleum	12	12	12	.0	.1	.1	.1
Hydroelectric	108	98	46	-9.1	.7	.6	.3
Total Electric Utilities	**14,448**	**14,491**	**10,166**	**-3.8**	**95.6**	**96.3**	**62.8**
Coal	495	384	4,608	28.1	3.3	2.6	28.5
Natural Gas	0	0	764	NM	.0	.0	4.7
Other Gases	25	25	95	16.0	.2	.2	.6
Dual Fired	11	11	292	44.2	.1	.1	1.8
Hydroelectric	140	140	189	3.4	.9	.9	1.2
Other Renewables	0	0	66	NM	.0	.0	.4
Total IPP's & Combined Heat and Power	**671**	**560**	**6,014**	**27.6**	**4.4**	**3.7**	**37.2**
Coal	14,823	14,765	14,716	-.1	98.0	98.1	91.0
Petroleum	12	12	12	.0	.1	.1	.1
Natural Gas	0	0	764	NM	.0	.0	4.7
Other Gases	25	25	95	16.0	.2	.2	.6
Dual Fired	11	11	292	44.2	.1	.1	1.8
Hydroelectric	247	238	235	-.6	1.6	1.6	1.5
Other Renewables	0	0	66	NM	.0	.0	.4
Total Electric Industry	**15,118**	**15,051**	**16,180**	**.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
West Virginia							
Coal	70,491,516	87,714,945	62,801,799	-1.3	94.3	95.8	66.3
Petroleum	210,975	170,969	278,679	3.1	.3	.2	.3
Natural Gas	13,461	21,355	3,396	-14.2	.0	.0	.0
Hydroelectric	362,117	377,192	235,958	-4.6	.5	.4	.2
Other Renewables	0	0	21,788	NM	.0	.0	.0
Total Electric Utilities	**71,078,069**	**88,284,461**	**63,341,620**	**-1.3**	**95.1**	**96.5**	**66.8**
Coal	2,477,147	2,130,584	30,149,517	32.0	3.3	2.3	31.8
Petroleum	25,959	18,629	18,908	-3.5	.0	.0	.0
Natural Gas	144,782	195,391	237,744	5.7	.2	.2	.3
Other Gases	271,186	138,004	174,598	-4.8	.4	.2	.2
Hydroelectric	751,984	761,577	829,778	1.1	1.0	.8	.9
Other Renewables	0	0	9,586	NM	.0	.0	.0
Other	36	231	0	NM	.0	.0	.0
Total IPP's & Combined Heat and Power	**3,671,094**	**3,244,416**	**31,420,132**	**26.9**	**4.9**	**3.5**	**33.2**
Coal	72,968,663	89,845,529	92,951,316	2.7	97.6	98.2	98.1
Petroleum	236,934	189,598	297,587	2.6	.3	.2	.3
Natural Gas	158,243	216,746	241,140	4.8	.2	.2	.3
Other Gases	271,186	138,004	174,598	-4.8	.4	.2	.2
Hydroelectric	1,114,101	1,138,769	1,065,736	-.5	1.5	1.2	1.1
Other Renewables	0	0	31,374	NM	.0	.0	.0
Other	36	231	0	NM	.0	.0	.0
Total Electric Industry	**74,749,163**	**91,528,877**	**94,761,752**	**2.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
West Virginia				
Coal (2002 cents per million Btu)	158.1	127.2	120.6	-3.0
Average heat value (Btu per pound)	12,489	12,398	12,117	-.3
Average sulfur Content(percent)	1.9	2.0	1.7	-1.4
Petroleum (2002 cents per million Btu)	515.0	476.9	543.1	.6
Average heat value (Btu per gallon)	139,231	138,884	139,276	.0
Average sulfur Content(percent)	.2	.0	.2	2.0
Gas (2002 cents per million Btu)	485.5	344.4	385.4	-2.5
Average heat value (Btu per cubic foot)	1,000	1,000	1,036	.4

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002 (Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
West Virginia				
Sulfur Dioxide				
Coal	1,028	673	522	-7.3
Petroleum	*	1	1	5.5
Gas	*	*	*	10.7
Total	1,028	673	523	-7.2
Nitrogen Oxide				
Coal	285	339	233	-2.2
Petroleum	*	*	*	-5.5
Gas	9	5	9	.9
Other	0	0	0	NM
Total	294	344	243	-2.1
Carbon Dioxide				
Coal	72,987	89,358	94,544	2.9
Petroleum	190	151	187	-.2
Gas	300	220	440	4.3
Total	73,477	89,729	95,170	2.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
West Virginia							
Retail Sales (thousand megawatthours)							
Residential	8,682	9,027	10,444	2.1	35.5	34.4	36.7
Commercial	5,480	5,944	7,039	2.8	22.4	22.6	24.7
Industrial	10,187	11,180	10,902	.8	41.7	42.6	38.3
Other	92	96	78	−1.8	.4	.4	.3
Total	24,442	26,247	28,463	1.7	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	609	580	651	.7	42.9	42.9	44.8
Commercial	353	338	381	.8	24.8	25.0	26.2
Industrial	450	426	415	−.9	31.6	31.5	28.5
Other	9	9	8	−2.1	.7	.6	.5
Total	1,421	1,354	1,455	.3	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.02	6.43	6.23	−1.3	NA	NA	NA
Commercial	6.44	5.69	5.41	−1.9	NA	NA	NA
Industrial	4.41	3.81	3.81	−1.6	NA	NA	NA
Other	10.27	8.95	10.01	−.3	NA	NA	NA
Total	5.82	5.16	5.11	−1.4	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
West Virginia						
Number of Entities	8	7	0	1	0	16
Number of Retail Customers	48,879	913,870	0	5,916	0	968,665
Retail Sales (thousand megawatthours)	1,842	26,563	0	59	0	28,463
Percentage of Retail Sales	6.47	93.32	.00	.21	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	90	1,359	0	5	0	1,455
Percentage of Revenue	6.20	93.44	.00	.36	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	4.89	5.12	.00	9.02	0	5.11

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Wisconsin		
NERC Region(s)		MAIN/MAPP
Primary Energy Source		Coal
Net Summer Capability (megawatts)	14,237	24
Electric Utilities	12,511	19
Independent Power Producers & Combined Heat and Power	1,726	32
Net Generation (megawatthours)	58,431,438	24
Electric Utilities	54,773,666	19
Independent Power Producers & Combined Heat and Power	3,657,772	36
Emissions (thousand short tons)		
Sulfur Dioxide	219	18
Nitrogen Oxide	98	20
Carbon Dioxide	49,065	21
Sulfur Dioxide/sq. mile	4	24
Nitrogen Oxide/sq. mile	2	25
Carbon Dioxide/sq. mile	903	27
Utility and ESP Retail Electricity Sales (megawatthours)	66,999,296	21
Utility Retail Electricity Sales (megawatthours)	66,999,296	21
Direct Use (megawatthours)	2,641,816	17
Average Retail Price (cents/kWh)	6.28	26

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Wisconsin			
1. Pleasant Prairie	Petroleum, Gas, Coal	Wisconsin Electric Power Co	1,226
2. South Oak Creek	Gas, Coal	Wisconsin Electric Power Co	1,153
3. Columbia	Petroleum, Coal	Wisconsin Power & Light Co	1,098
4. Point Beach	Petroleum, Nuclear	Wisconsin Electric Power Co	1,027
5. Edgewater	Petroleum, Other, Coal	Wisconsin Power & Light Co	836
6. Weston	Petroleum, Gas, Coal	Wisconsin Public Service Corp	545
7. Kewaunee	Nuclear	Wisconsin Public Service Corp	498
8. RockGen Energy Center	Petroleum, Gas	RockGen Energy LLC	462
9. Paris	Petroleum, Gas	Wisconsin Electric Power Co	400
10. Pulliam	Gas, Coal	Wisconsin Public Service Corp	389

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Wisconsin					
A. Wisconsin Electric Power Co	25,012,143	7,983,219	8,327,117	8,534,675	167,132
B. Wisconsin Public Service Corp	10,292,027	2,962,175	3,379,562	3,915,424	34,866
C. Wisconsin Power & Light Co	9,896,116	3,361,423	2,107,342	4,364,712	62,639
D. Northern States Power Company	5,623,050	1,818,662	1,025,215	2,741,386	37,787
E. Madison Gas & Electric Company	3,104,384	839,005	1,640,190	296,220	328,969
Total	53,927,720	16,964,484	16,479,426	19,852,417	631,393
Percentage of Utility Sales	80	79	86	78	85

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Wisconsin							
Coal	7,276	7,389	7,186	-0.1	63.4	58.8	50.5
Petroleum	797	852	985	2.4	6.9	6.8	6.9
Natural Gas	104	71	340	14.1	.9	.6	2.4
Dual Fired	721	1,580	1,998	12.0	6.3	12.6	14.0
Nuclear	1,496	1,432	1,510	.1	13.0	11.4	10.6
Hydroelectric	440	460	425	-.4	3.8	3.7	3.0
Other Renewables	104	61	66	-4.8	.9	.5	.5
Total Electric Utilities	**10,938**	**11,845**	**12,511**	**1.5**	**95.3**	**94.2**	**87.9**
Coal	375	392	313	-2.0	3.3	3.1	2.2
Petroleum	8	3	3	-9.3	.1	.0	.0
Natural Gas	20	21	185	28.3	.2	.2	1.3
Dual Fired	15	189	951	58.3	.1	1.5	6.7
Hydroelectric	63	54	69	1.0	.6	.4	.5
Other Renewables	63	68	184	12.6	.5	.5	1.3
Other	0	0	21	NM	.0	.0	.1
Total IPP's & Combined Heat and Power	**544**	**728**	**1,726**	**13.7**	**4.7**	**5.8**	**12.1**
Coal	7,651	7,782	7,500	-.2	66.6	61.9	52.7
Petroleum	805	855	989	2.3	7.0	6.8	6.9
Natural Gas	123	92	525	17.5	1.1	.7	3.7
Dual Fired	736	1,770	2,949	16.7	6.4	14.1	20.7
Nuclear	1,496	1,432	1,510	.1	13.0	11.4	10.6
Hydroelectric	504	513	494	-.2	4.4	4.1	3.5
Other Renewables	167	129	250	4.6	1.5	1.0	1.8
Other	0	0	21	NM	.0	.0	.1
Total Electric Industry	**11,481**	**12,573**	**14,237**	**2.4**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Wisconsin							
Coal	33,558,049	40,819,517	38,583,501	1.6	66.8	79.4	66.0
Petroleum	105,173	169,863	162,990	5.0	.2	.3	.3
Natural Gas	224,276	1,100,895	973,287	17.7	.4	2.1	1.7
Nuclear	11,464,574	3,915,871	12,448,813	.9	22.8	7.6	21.3
Hydroelectric	2,191,053	2,182,208	2,282,883	.5	4.4	4.2	3.9
Other Renewables	219,736	371,773	322,192	4.3	.4	.7	.6
Total Electric Utilities	**47,762,861**	**48,560,127**	**54,773,666**	**1.5**	**95.1**	**94.4**	**93.7**
Coal	992,897	1,156,968	1,223,983	2.4	2.0	2.3	2.1
Petroleum	230,382	240,887	259,687	1.3	.5	.5	.4
Natural Gas	187,401	323,459	1,103,027	21.8	.4	.6	1.9
Hydroelectric	295,533	301,086	232,134	-2.6	.6	.6	.4
Other Renewables	769,478	831,482	838,941	1.0	1.5	1.6	1.4
Total IPP's & Combined Heat and Power	**2,475,691**	**2,853,882**	**3,657,772**	**4.4**	**4.9**	**5.6**	**6.3**
Coal	34,550,946	41,976,485	39,807,484	1.6	68.8	81.6	68.1
Petroleum	335,555	410,750	422,677	2.6	.7	.8	.7
Natural Gas	411,677	1,424,354	2,076,314	19.7	.8	2.8	3.6
Nuclear	11,464,574	3,915,871	12,448,813	.9	22.8	7.6	21.3
Hydroelectric	2,486,586	2,483,294	2,515,017	.1	4.9	4.8	4.3
Other Renewables	989,214	1,203,255	1,161,133	1.8	2.0	2.3	2.0
Total Electric Industry	**50,238,552**	**51,414,009**	**58,431,438**	**1.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Wisconsin				
Coal (2002 cents per million Btu)	134.9	112.0	112.2	-2.0
Average heat value (Btu per pound)	9,490	9,375	9,753	.3
Average sulfur Content(percent)	.5	.5	.4	-2.0
Petroleum (2002 cents per million Btu)	170.0	185.3	110.6	-4.7
Average heat value (Btu per gallon)	92,736	90,762	137,686	4.5
Average sulfur Content(percent)	5.3	5.7	5.2	-.2
Gas (2002 cents per million Btu)	293.2	323.5	353.7	2.1
Average heat value (Btu per cubic foot)	1,012	1,008	983	-.3

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Wisconsin				
Sulfur Dioxide				
Coal	195	255	208	0.7
Petroleum	8	9	9	.8
Gas	0	0	0	NM
Other	7	3	2	-12.9
Total	211	267	219	.4
Nitrogen Oxide				
Coal	167	118	93	-6.3
Petroleum	1	1	1	.1
Gas	1	1	2	9.6
Other	2	3	2	-.2
Total	171	123	98	-6.0
Carbon Dioxide				
Coal	38,678	47,680	46,939	2.2
Petroleum	341	531	525	4.9
Gas	324	1,163	1,601	19.4
Other	1	*	0	NM
Total	39,344	49,375	49,065	2.5

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Wisconsin							
Retail Sales (thousand megawatthours)							
Residential	17,373	18,510	21,575	2.4	32.7	30.8	32.2
Commercial	13,710	15,730	19,144	3.8	25.8	26.2	28.6
Industrial	21,410	25,103	25,534	2.0	40.3	41.8	38.1
Other	662	751	746	1.3	1.3	1.3	1.1
Total	53,156	60,094	66,999	2.6	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	1,361	1,308	1,765	2.9	41.6	40.6	41.9
Commercial	908	905	1,253	3.6	27.8	28.1	29.8
Industrial	950	959	1,131	2.0	29.0	29.7	26.9
Other	51	52	60	1.8	1.6	1.6	1.4
Total	3,270	3,224	4,209	2.8	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	7.83	7.07	8.18	.5	NA	NA	NA
Commercial	6.62	5.75	6.54	-.1	NA	NA	NA
Industrial	4.44	3.82	4.43	*	NA	NA	NA
Other	7.78	6.96	8.08	.4	NA	NA	NA
Total	6.15	5.36	6.28	.2	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Wisconsin						
Number of Entities	8	90	0	20	0	118
Number of Retail Customers	580,174	1,932,973	0	200,835	0	2,713,982
Retail Sales (thousand megawatthours)	15,152	49,023	0	2,825	0	66,999
Percentage of Retail Sales	22.61	73.17	.00	4.22	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	934	3,050	0	225	0	4,209
Percentage of Revenue	22.20	72.46	.00	5.34	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	6.17	6.22	.00	7.96	0	6.28

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	U.S. Rank
Wyoming		
NERC Region(s)		WSCC
Primary Energy Source		Coal
Net Summer Capability (megawatts)	6,348	36
Electric Utilities	6,122	29
Independent Power Producers & Combined Heat and Power	226	46
Net Generation (megawatthours)	43,783,839	31
Electric Utilities	42,532,420	25
Independent Power Producers & Combined Heat and Power	1,251,419	44
Emissions (thousand short tons)		
Sulfur Dioxide	87	28
Nitrogen Oxide	89	23
Carbon Dioxide	49,117	20
Sulfur Dioxide/sq. mile	1	35
Nitrogen Oxide/sq. mile	1	36
Carbon Dioxide/sq. mile	506	35
Utility and ESP Retail Electricity Sales (megawatthours)	12,874,060	40
Utility Retail Electricity Sales (megawatthours)	12,874,060	40
Direct Use (megawatthours)	661,028	26
Average Retail Price (cents/kWh)	5	50

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
Wyoming			
1. Jim Bridger	Petroleum, Coal	PacifiCorp	2,120
2. Laramie River Station	Petroleum, Coal	Basin Electric Power Coop	1,650
3. Dave Johnston	Petroleum, Coal	PacifiCorp	762
4. Naughton	Gas, Coal	PacifiCorp	700
5. Wyodak	Petroleum, Coal	PacifiCorp	335
6. Neil Simpson II	Petroleum, Gas, Coal	Black Hills Corp	114
7. Fremont Canyon	Hydro	U S Bureau of Reclamation	67
8. Seminoe	Hydro	U S Bureau of Reclamation	52
9. Rock River I LLC	Other	SeaWest Windpower Inc	50
10. Foote Creek I	Other	Foote Creek I LLC	41

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Wyoming					
A. PacifiCorp	7,348,990	895,976	1,136,822	5,274,337	41,855
B. Powder River Energy Corp	1,768,690	164,410	684,675	918,685	920
C. Cheyenne Light Fuel & Power Co	920,334	216,888	327,785	371,718	3,943
D. High Plains Power, Inc	704,803	117,517	59,949	527,337	0
E. Lower Valley Energy Inc	534,277	299,728	221,829	12,139	581
Total	11,277,094	1,694,519	2,431,060	7,104,216	47,299
Percentage of Utility Sales	88	76	80	95	29

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Wyoming							
Coal	5,567	5,737	5,692	0.2	93.3	93.5	89.7
Petroleum	15	10	5	−11.9	.2	.2	.1
Natural Gas	0	0	119	NM	.0	.0	1.9
Hydroelectric	287	297	300	.5	4.8	4.8	4.7
Other Renewables	0	0	6	NM	.0	.0	.1
Total Electric Utilities	**5,869**	**6,044**	**6,122**	**.5**	**98.3**	**98.5**	**96.4**
Coal	28	28	30	.8	.5	.5	.5
Petroleum	0	0	4	NM	.0	.0	.1
Natural Gas	50	50	58	1.7	.8	.8	.9
Other Gases	3	3	0	NM	.1	.1	.0
Other Renewables	8	0	135	37.0	.1	.0	2.1
Other	11	11	0	NM	.2	.2	.0
Total IPP's & Combined Heat and Power	**99**	**91**	**226**	**9.6**	**1.7**	**1.5**	**3.6**
Coal	5,595	5,765	5,722	.2	93.7	94.0	90.1
Petroleum	15	10	8	−6.2	.2	.2	.1
Natural Gas	50	50	177	15.2	.8	.8	2.8
Other Gases	3	3	0	NM	.1	.1	.0
Hydroelectric	287	297	300	.5	4.8	4.8	4.7
Other Renewables	8	0	141	37.7	.1	.0	2.2
Other	11	11	0	NM	.2	.2	.0
Total Electric Industry	**5,968**	**6,136**	**6,348**	**.7**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Wyoming							
Coal	39,301,199	39,315,335	41,685,278	0.7	96.4	94.9	95.2
Petroleum	56,970	58,765	38,686	–4.2	.1	.1	.1
Natural Gas	8,999	10,274	205,791	41.6	.0	.0	.5
Hydroelectric	787,427	1,380,713	583,615	–3.3	1.9	3.3	1.3
Other Renewables	0	0	19,050	NM	.0	.0	.0
Total Electric Utilities	**40,154,595**	**40,765,087**	**42,532,420**	**.6**	**98.5**	**98.4**	**97.1**
Coal	205,893	184,458	237,883	1.6	.5	.4	.5
Petroleum	9,411	4,716	1,418	–19.0	.0	.0	.0
Natural Gas	356,541	375,288	507,289	4.0	.9	.9	1.2
Other Gases	2,072	7,124	0	NM	.0	.0	.0
Other Renewables	0	0	428,280	NM	.0	.0	1.0
Other	42,843	72,889	76,549	6.7	.1	.2	.2
Total IPP's & Combined Heat and Power	**616,760**	**644,476**	**1,251,419**	**8.2**	**1.5**	**1.6**	**2.9**
Coal	39,507,092	39,499,793	41,923,161	.7	96.9	95.4	95.8
Petroleum	66,381	63,481	40,104	–5.4	.2	.2	.1
Natural Gas	365,540	385,562	713,080	7.7	.9	.9	1.6
Other Gases	2,072	7,124	0	NM	.0	.0	.0
Hydroelectric	787,427	1,380,713	583,615	–3.3	1.9	3.3	1.3
Other Renewables	0	0	447,330	NM	.0	.0	1.0
Other	42,843	72,889	76,549	6.7	.1	.2	.2
Total Electric Industry	**40,771,355**	**41,409,563**	**43,783,839**	**.8**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Wyoming				
Coal (2002 cents per million Btu)	89.1	82.8	78.5	–1.4
Average heat value (Btu per pound)	8,779	8,787	8,802	*
Average sulfur Content(percent)	.5	.5	.5	–.5
Petroleum (2002 cents per million Btu)	527.3	531.4	553.0	.5
Average heat value (Btu per gallon)	139,060	138,823	142,302	.3
Average sulfur Content(percent)	.0	.0	.3	NM
Gas (2002 cents per million Btu)	367.6	900.2	255.2	–4.0
Average heat value (Btu per cubic foot)	1,044	1,041	944	–1.1

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
Wyoming				
Sulfur Dioxide				
Coal	79	105	87	1.1
Petroleum	*	*	*	-22.3
Gas	0	0	0	NM
Other	*	*	0	NM
Total	79	105	87	1.1
Nitrogen Oxide				
Coal	172	102	89	-7.1
Petroleum	*	*	0	NM
Gas	1	1	1	3.6
Total	173	102	89	-7.1
Carbon Dioxide				
Coal	45,089	45,025	48,652	.8
Petroleum	56	52	37	-4.3
Gas	215	221	428	7.9
Total	45,360	45,298	49,117	.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
Wyoming							
Retail Sales (thousand megawatthours)							
Residential	1,906	2,007	2,232	1.8	16.0	17.0	17.3
Commercial	2,493	2,394	3,027	2.2	21.0	20.3	23.5
Industrial	7,363	7,211	7,453	.1	61.9	61.2	57.9
Other	122	174	162	3.2	1.0	1.5	1.3
Total	11,885	11,786	12,874	.9	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	127	128	156	2.3	22.5	24.4	25.8
Commercial	140	130	173	2.4	24.9	24.7	28.7
Industrial	287	256	264	-.9	51.0	48.8	43.9
Other	9	10	10	.7	1.6	2.0	1.6
Total	563	525	602	.8	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	6.64	6.40	6.97	.5	NA	NA	NA
Commercial	5.62	5.42	5.71	.2	NA	NA	NA
Industrial	3.90	3.56	3.55	-1.0	NA	NA	NA
Other	7.37	6.01	5.93	-2.4	NA	NA	NA
Total	4.73	4.45	4.68	-.1	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
Wyoming						
Number of Entities	1	29	0	5	0	35
Number of Retail Customers	36,922	227,219	0	21,743	0	285,884
Retail Sales (thousand megawatthours)	920	11,012	0	942	0	12,874
Percentage of Retail Sales	7.15	85.53	.00	7.32	.00	100.00
Revenue from Retail Sales (million 2002 dollars)	72	482	0	48	0	602
Percentage of Revenue	11.94	80.06	.00	8.00	.00	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.82	4.38	.00	5.12	0	4.68

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table 1. 2002 Summary Statistics

Item	Value	Highest	Lowest
United States			
Primary Energy Source	Coal		
Net Summer Capability (megawatts)	905,301	Texas	District of Columbia
Electric Utilities	561,074	Florida	Rhode Island
Independent Power Producers & Combined Heat and Power	344,227	Texas	Nebraska
Net Generation (megawatthours)	3,858,452,252	Texas	District of Columbia
Electric Utilities	2,549,457,170	Florida	Maine
Independent Power Producers & Combined Heat and Power	1,308,995,082	Texas	Nebraska
Emissions (thousand short tons)			
Sulfur Dioxide	10,940	Ohio	Vermont
Nitrogen Oxide	5,159	Ohio	Vermont
Carbon Dioxide	2,549,969	Texas	Vermont
Sulfur Dioxide/sq. mile	3	Ohio	Vermont
Nitrogen Oxide/sq. mile	1	Maryland	Alaska
Carbon Dioxide/sq. mile	721	District of Columbia	Vermont
Utility and Energy Service Providers (megawatthours)	3,462,520,834	Texas	Alaska
Utility Retail Electricity Sales (megawatthours)	3,290,401,013	Texas	Maine
Energy Service Providers Electricity Sales (megawatthours)	172,119,821	California	Texas
Direct Use (megawatthours)	171,472,756	Texas	Washington
Utility Average Retail Price (cents/kWh)	7.21	Hawaii	Kentucky
Utility Average Retail Price (cents/kWh)	7.21	Hawaii	Kentucky

See footnotes at end of tables.

Table 2. Ten Largest Plants by Generating Capability, 2002

Plant	Energy Sources	Operating Company	Net Capability (MW)
United States			
1. Grand Coulee	Hydro	U S Bureau of Reclamation	7,079
2. W A Parish	Gas, Coal	CenterPoint Energy Houston Elec	3,766
3. Palo Verde	Nuclear	Arizona Public Service Co	3,733
4. Scherer	Petroleum, Coal	Georgia Power Co	3,430
5. Bowen	Petroleum, Coal	Georgia Power Co	3,294
6. Browns Ferry	Nuclear	Tennessee Valley Authority	3,291
7. Crystal River	Petroleum, Nuclear, Coal	Florida Power Corp	3,144
8. Gibson	Petroleum, Coal	PSI Energy Inc	3,131
9. Monroe	Petroleum, Coal	Detroit Edison Co	3,034
10. John E Amos	Petroleum, Coal	Appalachian Power Co	2,900

See footnotes at end of tables.

Table 3. Top Five Utilities Ranked by Retail Sales, 2002
(Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
United States					
A. Florida Power & Light Company	95,542,625	50,875,435	40,037,337	4,058,048	571,805
B. TXU Energy Retail Co LP	89,456,982	37,118,787	20,133,202	32,204,993	0
C. Georgia Power Company	75,432,469	22,144,559	26,954,922	25,739,785	593,203
D. Duke Energy Corporation	75,362,408	24,685,433	24,252,706	26,154,340	269,929
E. Commonwealth Edison Company	73,835,297	27,474,341	25,517,175	13,016,569	7,827,212
Total	409,629,781	162,298,555	136,895,342	101,173,735	9,262,149
Percentage of Utility Sales	12	13	12	10	9

See footnotes at end of tables.

Table 4. Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002
(Megawatts)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
United States							
Coal	300,634	302,866	244,056	-2.3	39.8	38.9	27.0
Petroleum	42,699	41,545	23,067	-6.6	5.7	5.3	2.5
Natural Gas	49,709	53,552	50,026	.1	6.6	6.9	5.5
Other Gases	698	206	61	-23.7	.1	.0	.0
Dual Fired	109,066	116,174	88,476	-2.3	14.5	14.9	9.8
Nuclear	99,041	99,716	63,202	-4.9	13.1	12.8	7.0
Hydroelectric	95,910	95,487	91,198	-.6	12.7	12.3	10.1
Other Renewables	2,215	2,123	989	-8.6	.3	.3	.1
Other	0	222	0	NM	.0	.0	.0
Total Electric Utilities	**699,971**	**711,889**	**561,074**	**-2.4**	**92.8**	**91.4**	**62.0**
Coal	9,513	10,758	71,294	25.1	1.3	1.4	7.9
Petroleum	1,321	1,657	15,147	31.1	.2	.2	1.7
Natural Gas	15,814	22,797	121,635	25.4	2.1	2.9	13.4
Other Gases	1,233	1,320	1,947	5.2	.2	.2	.2
Dual Fired	11,091	13,209	73,813	23.4	1.5	1.7	8.2
Nuclear	0	0	35,455	NM	.0	.0	3.9
Hydroelectric	2,647	3,237	8,529	13.9	.4	.4	.9
Other Renewables	12,441	13,229	15,766	2.7	1.6	1.7	1.7
Other	550	552	641	1.7	.1	.1	.1
Total IPP's & Combined Heat and Power	**54,611**	**66,760**	**344,227**	**22.7**	**7.2**	**8.6**	**38.0**
Coal	310,148	313,624	315,350	.2	41.1	40.3	34.8
Petroleum	44,019	43,202	38,213	-1.6	5.8	5.5	4.2
Natural Gas	65,523	76,348	171,660	11.3	8.7	9.8	19.0
Other Gases	1,931	1,525	2,008	.4	.3	.2	.2
Dual Fired	120,157	129,384	162,289	3.4	15.9	16.6	17.9
Nuclear	99,041	99,716	98,657	.0	13.1	12.8	10.9
Hydroelectric	98,557	98,725	99,727	.1	13.1	12.7	11.0
Other Renewables	14,656	15,351	16,755	1.5	1.9	2.0	1.9
Other	550	774	641	1.7	.1	.1	.1
Total Electric Industry	**754,582**	**778,649**	**905,301**	**2.0**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 5. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002
(Megawatthours)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
United States							
Coal	1,639,151,186	1,787,806,344	1,514,669,950	-0.9	51.3	51.2	39.3
Petroleum	99,538,857	77,752,652	59,124,871	-5.6	3.1	2.2	1.5
Natural Gas	258,915,301	283,624,806	229,639,287	-1.3	8.1	8.1	6.0
Other Gases	0	0	206,469	NM	.0	.0	.0
Nuclear	610,291,214	628,644,171	507,379,828	-2.0	19.1	18.0	13.1
Hydroelectric	265,062,757	337,233,538	234,868,263	-1.3	8.3	9.7	6.1
Other Renewables	9,565,451	7,461,633	3,568,503	-10.4	.3	.2	.1
Total Electric Utilities	**2,882,524,766**	**3,122,523,144**	**2,549,457,170**	**-1.4**	**90.2**	**89.4**	**66.1**
Coal	50,919,046	57,209,393	418,460,404	26.4	1.6	1.6	10.8
Petroleum	13,249,326	14,802,220	35,442,523	11.6	.4	.4	.9
Natural Gas	156,011,497	195,773,865	461,366,458	12.8	4.9	5.6	12.0
Other Gases	12,955,798	13,350,633	11,256,217	-1.6	.4	.4	.3
Nuclear	0	0	272,684,259	NM	.0	.0	7.1
Hydroelectric	11,395,678	15,179,853	20,717,642	6.9	.4	.4	.5
Other Renewables	66,647,831	69,721,185	83,353,589	2.5	2.1	2.0	2.2
Other	3,487,156	3,611,990	5,713,990	5.6	.1	.1	.1
Total IPP's & Combined Heat and Power	**314,666,332**	**369,649,138**	**1,308,995,082**	**17.2**	**9.8**	**10.6**	**33.9**
Coal	1,690,070,232	1,845,015,737	1,933,130,354	1.5	52.9	52.8	50.1
Petroleum	112,788,183	92,554,872	94,567,394	-1.9	3.5	2.7	2.5
Natural Gas	414,926,798	479,398,671	691,005,745	5.8	13.0	13.7	17.9
Other Gases	12,955,798	13,350,633	11,462,686	-1.4	.4	.4	.3
Nuclear	610,291,214	628,644,171	780,064,087	2.8	19.1	18.0	20.2
Hydroelectric	276,458,435	352,413,391	255,585,905	-.9	8.6	10.1	6.6
Other Renewables	76,213,282	77,182,818	86,922,092	1.5	2.4	2.2	2.3
Other	3,487,156	3,611,990	5,713,990	5.6	.1	.1	.1
Total Electric Industry	**3,197,191,098**	**3,492,172,282**	**3,858,452,252**	**2.1**	**100.0**	**100.0**	**100.0**

See footnotes at end of tables.

Table 6. Electric Power Delivered Fuel Prices for Coal, Petroleum, and Natural Gas, 1993, 1997, and 2002

Fuel	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
United States				
Coal (2002 cents per million Btu)	154.4	130.8	125.5	-2.3
Average heat value (Btu per pound)	10,315	10,275	10,157	-.2
Average sulfur Content(percent)	1.2	1.1	.9	-2.5
Petroleum (2002 cents per million Btu)	264.6	280.6	334.3	2.6
Average heat value (Btu per gallon)	136,888	137,405	143,493	-.3
Average sulfur Content(percent)	1.4	1.4	1.6	1.9
Gas (2002 cents per million Btu)	285.4	283.6	356.0	2.5
Average heat value (Btu per cubic foot)	1,023	1,019	1,021	*

See footnotes at end of tables.

Table 7. Electric Power Industry Emissions Estimates, 1993, 1997, and 2002
(Thousand Short Tons)

Emission Type	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)
United States				
Sulfur Dioxide				
Coal	14,751	12,925	10,257	–4.0
Petroleum	855	740	582	–4.2
Gas	1	1	*	–8.8
Other	96	95	101	.5
Total	15,702	13,760	10,940	–3.9
Nitrogen Oxide				
Coal	6,824	5,875	4,337	–4.9
Petroleum	150	151	137	–1.0
Gas	583	599	587	.1
Other	78	84	98	2.6
Total	7,636	6,708	5,159	–4.3
Carbon Dioxide				
Coal	1,794,282	1,972,290	2,083,568	1.7
Petroleum	103,494	85,484	89,390	–1.6
Gas	243,960	279,506	373,655	4.8
Other	2,641	3,217	3,356	2.7
Total	2,144,376	2,340,497	2,549,969	1.9

See footnotes at end of tables.

Table 8. Retail Sales, Revenue, and Average Revenue per Kilowatthour by Sector, 1993, 1997, and 2001

Sector	1993	1997	2002	Annual Growth Rate 1993-2002 (Percent)	Percentage Share 1993	Percentage Share 1997	Percentage Share 2002
United States							
Retail Sales (thousand megawatthours)							
Residential	994,781	1,075,880	1,266,959	2.7	34.8	34.2	36.6
Commercial	794,573	928,633	1,116,248	3.8	27.8	29.5	32.2
Industrial	977,164	1,038,197	972,168	–.1	34.1	33.0	28.1
Other	94,944	102,901	107,146	1.3	3.3	3.3	3.1
Total	2,861,462	3,145,610	3,462,521	2.1	100.0	100.0	100.0
Retail Sales Revenue (million 2002 dollars)							
Residential	92,251	93,212	107,229	1.7	41.8	42.1	43.0
Commercial	68,532	72,446	87,706	2.8	31.0	32.7	35.1
Industrial	52,754	48,323	47,486	–1.2	23.9	21.8	19.0
Other	7,272	7,307	7,208	–.1	3.3	3.3	2.9
Total	220,809	221,287	249,629	1.4	100.0	100.0	100.0
Average Revenue per Kilowatthour (2002 cents/kWh)							
Residential	9.27	8.66	8.46	–1.0	NA	NA	NA
Commercial	8.63	7.80	7.86	–1.0	NA	NA	NA
Industrial	5.40	4.65	4.88	–1.1	NA	NA	NA
Other	7.66	7.10	6.73	–1.4	NA	NA	NA
Total	7.72	7.03	7.21	–.8	NA	NA	NA

See footnotes at end of tables.

Table 9. Utility Retail Sales Statistics, 2002

Item	Investor-Owned	Public	Federal	Cooperative	Energy Service Providers	Total
United States						
Number of Entities	196	1,986	6	825	71	3,084
Number of Retail Customers	89,708,610	24,853,095	38,695	15,740,366	3,022,267	133,363,033
Retail Sales (thousand megawatthours)	2,191,647	734,371	36,482	327,901	172,120	3,462,521
Percentage of Retail Sales	63.30	21.21	1.05	9.47	4.97	100.00
Revenue from Retail Sales (million 2002 dollars)	165,842	49,195	997	22,712	10,884	249,629
Percentage of Revenue	66.44	19.71	.40	9.10	4.36	100.00
Revenue per Kilowatthour (2002 cents/kWh)	7.57	6.70	2.73	6.93	0	7.21

IPP = Independent Power Producer.
NA = Not available.
NM = Not meaningful.
* = 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 "*".)

Table A3. Selected Summary Statistics by State, 2002

State	Primary Fuel Source	Industry Capacity		Industry Net Generation		Industry Sulfur Dioxide Emissions		Industry Nitrogen Oxide Emissions		Industry Carbon Dioxide Emissions	
		(MW)	Rank	(MWh)	Rank	(1000 Short Tons)	Rank	(1000 Short Tons)	Rank	(1000 Short Tons)	Rank
Alabama	Coal	3,180	23	132,864,589	8	467	10	15,523	21	3,550,362	27
Alaska	Gas	268	45	6,009,538	48	4	48	3,015	36	1,101,941	40
Arizona	Coal	3,759	19	93,997,673	18	72	31	2,809	37	5,632,091	23
Arkansas	Coal	1,759	31	47,605,260	27	80	29	3,669	34	1,671,465	37
California	Other	32,079	4	181,901,069	5	48	37	69,883	7	47,305,827	4
Colorado	Coal	1,840	30	45,537,221	30	90	27	4,380	33	2,833,791	30
Connecticut	Other	7,365	11	31,289,755	39	11	46	9,634	24	9,719,038	17
Delaware	Other	3,332	22	5,998,707	49	33	40	11,657	23	5,838,190	22
District of Columbia	Other	806	40	261,980	52	1	49	652	46	288,010	46
Florida	Coal	6,781	12	203,040,185	3	502	7	33,677	13	11,930,275	15
Georgia	Coal	8,806	10	126,435,529	9	566	5	18,689	20	5,992,723	21
Hawaii	Petroleum	646	42	10,723,346	44	29	41	6,546	30	3,109,298	29
Idaho	Hydro	577	43	9,501,547	45	5	47	2,054	39	752,414	42
Illinois	Nuclear	40,565	2	187,814,268	4	405	11	153,072	3	82,144,132	3
Indiana	Coal	4,471	16	125,525,338	10	786	3	96,625	5	12,230,989	14
Iowa	Coal	939	39	42,419,062	33	148	22	6,847	29	1,802,006	36
Kansas	Coal	162	48	46,940,923	29	130	24	36	50	19,212	49
Kentucky	Coal	3,719	20	92,078,359	19	485	8	30,980	15	14,852,203	12
Louisiana	Other	11,414	8	94,953,987	16	181	20	56,453	9	26,001,203	8
Maine	Other	4,272	18	22,534,168	42	14	43	9,055	25	7,359,723	20
Maryland	Other	11,790	7	48,248,354	26	256	14	106,332	4	34,285,316	6
Massachusetts	Other	11,070	9	41,778,569	34	97	26	34,922	12	25,122,162	9
Michigan	Coal	6,079	13	117,063,685	12	355	12	20,126	18	7,726,808	18
Minnesota	Coal	968	38	52,162,033	25	111	25	7,522	28	2,718,765	31
Mississippi	Coal	4,812	15	42,868,458	32	72	30	3,377	35	4,473,387	26
Missouri	Coal	1,412	36	81,916,661	20	246	16	1,704	41	918,635	41
Montana	Other	2,942	26	25,459,514	41	45	38	38,672	10	17,886,411	11
Nebraska	Coal	23	50	31,580,411	37	68	32	284	48	85,203	48
Nevada	Coal	1,477	35	32,088,935	36	49	35	1,426	42	2,641,574	33
New Hampshire	Nuclear	2,323	28	15,949,805	43	44	39	1,750	40	167,088	47
New Jersey	Nuclear	17,141	6	61,569,387	22	49	36	35,713	11	20,304,116	10
New Mexico	Coal	479	44	30,281,024	40	51	33	630	47	405,058	45
New York	Other	24,378	5	139,221,428	7	233	17	69,724	8	41,386,756	5
North Carolina	Coal	3,046	24	124,438,359	11	483	9	20,582	17	5,556,100	24
North Dakota	Coal	45	49	31,306,296	38	144	23	1,334	44	433,882	44
Ohio	Coal	3,619	21	146,863,692	6	1172	1	33,147	14	7,492,248	19
Oklahoma	Coal	2,858	27	58,317,247	23	166	21	12,756	22	5,413,559	25
Oregon	Hydro	2,147	29	46,992,449	28	14	44	1,425	43	2,644,070	32
Pennsylvania	Other	34,901	3	204,122,080	2	892	2	193,868	2	111,507,762	2
Rhode Island	Other	1,715	33	7,044,929	47	*	50	1,303	45	3,293,668	28
South Carolina	Nuclear	1,281	37	96,489,284	14	216	19	5,136	31	1,560,925	38
South Dakota	Hydro	3	51	7,721,434	46	13	45	16	51	3,845	50
Tennessee	Coal	1,606	34	96,060,371	15	345	13	7,790	27	2,051,844	35
Texas	Other	55,624	1	385,245,998	1	629	4	201,994	1	142,155,826	1
Utah	Coal	185	47	36,259,169	35	51	34	4,623	32	687,248	43
Vermont	Nuclear	733	41	5,161,700	50	*	51	141	49	17	51
Virginia	Coal	4,403	17	74,978,258	21	251	15	27,218	16	9,860,466	16
Washington	Hydro	2,995	25	101,687,596	13	21	42	19,735	19	12,331,658	13
West Virginia	Coal	6,024	14	94,714,418	17	523	6	71,428	6	31,240,232	7
Wisconsin	Coal	1,738	32	58,009,442	24	219	18	8,158	26	2,535,111	34
Wyoming	Coal	232	46	43,775,399	31	87	28	2,135	38	1,236,251	39

Table A3. Selected Summary Statistics by State, 2002 (Continued)

State	Industry Electricity Consumption (excluding losses)		Utility Retail Sales		Nonutility RetailSales and Direct Use		Utility Average Electricty Price	
	(MWh	Rank	(MWh)	Rank	(MWh)	Rank	(cents/kWh)	Rank
Alabama	83,067,078	15	83,067,078	15	15,833,770	18	5.71	41
Alaska	5,465,489	51	5,465,489	50	2,406,875	41	10.46	7
Arizona	62,600,737	23	62,600,737	22	12,829,592	22	7.21	16
Arkansas	42,449,558	30	42,449,558	30	7,256,399	29	5.61	42
California	235,248,942	2	171,531,228	3	143,007,281	4	12.50	2
Colorado	45,936,696	27	45,936,696	26	4,629,794	36	6.00	34
Connecticut	30,905,605	33	30,615,280	33	35,202,076	10	9.73	9
Delaware	11,557,069	42	10,863,633	41	6,399,272	34	7.05	17
District of Columbia	11,066,099	43	5,680,946	48	265,973	49	7.37	14
Florida	210,473,530	3	210,473,530	2	28,604,644	12	7.31	15
Georgia	123,789,078	8	123,789,078	7	20,631,692	15	6.24	28
Hawaii	9,891,638	46	9,891,638	45	4,824,783	35	13.39	1
Idaho	20,699,666	38	20,699,666	38	1,783,951	43	5.58	44
Illinois	137,665,583	7	121,879,478	9	178,685,520	3	6.97	18
Indiana	101,428,550	11	101,428,550	11	18,713,113	17	5.34	48
Iowa	40,897,543	31	40,897,543	31	3,915,639	39	6.01	33
Kansas	36,713,540	32	36,713,540	32	534,003	47	6.31	25
Kentucky	87,266,835	14	87,266,835	14	13,102,899	21	4.26	51
Louisiana	79,260,989	16	79,260,989	16	63,600,311	7	5.99	35
Maine	9,635,779	47	1,025,206	51	27,790,563	13	11.36	3
Maryland	66,928,026	22	59,271,452	24	49,809,051	8	6.21	31
Massachusetts	52,409,743	25	43,879,763	29	43,409,654	9	10.18	8
Michigan	107,310,696	10	102,810,494	10	20,898,119	14	6.92	19
Minnesota	62,162,361	24	62,162,361	23	7,117,031	31	5.84	36
Mississippi	45,451,850	28	45,451,850	27	10,250,465	24	6.24	29
Missouri	75,000,629	19	75,000,629	19	1,693,685	44	6.09	32
Montana	12,574,530	41	10,323,186	42	19,537,245	16	5.75	39
Nebraska	25,661,061	36	25,661,061	36	135,313	50	5.55	45
Nevada	29,204,272	34	29,204,272	34	7,467,883	28	8.42	12
New Hampshire	10,490,029	44	10,319,936	43	4,175,124	38	10.49	6
New Jersey	74,460,421	20	73,368,045	20	76,183,910	6	9.31	10
New Mexico	19,206,917	39	19,206,917	39	1,303,582	45	6.73	21
New York	143,563,666	5	123,931,972	6	106,677,615	5	11.29	4
North Carolina	122,686,468	9	122,686,468	8	12,390,674	23	6.74	20
North Dakota	10,219,353	45	10,219,353	44	354,983	48	5.45	46
Ohio	155,999,230	4	135,562,777	4	8,345,717	26	6.66	22
Oklahoma	49,485,466	26	49,485,466	25	9,498,378	25	5.59	43
Oregon	45,255,173	29	45,255,173	28	8,070,608	27	6.32	24
Pennsylvania	140,786,670	6	129,654,562	5	182,931,299	2	8.01	13
Rhode Island	7,543,652	49	6,633,124	47	7,238,022	30	9.19	11
South Carolina	77,819,392	17	77,819,392	17	4,585,283	37	5.83	37
South Dakota	8,936,801	48	8,936,801	46	N/A	N/A	6.26	27
Tennessee	98,233,027	13	98,233,027	13	6,918,697	32	5.72	40
Texas	320,845,849	1	320,844,140	1	281,726,209	1	6.62	23
Utah	23,267,188	37	23,267,188	37	953,944	46	5.39	47
Vermont	5,629,263	50	5,629,263	49	2,520,977	40	10.87	5
Virginia	100,540,736	12	100,305,309	12	14,587,803	19	6.23	30
Washington	76,491,883	18	75,403,856	18	13,193,918	20	5.80	38
West Virginia	28,463,122	35	28,463,122	35	33,338,308	11	5.11	49
Wisconsin	66,999,296	21	66,999,296	21	6,610,574	33	6.28	26

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Cost and Quality of Fuels for Electric Utility Plants 2001

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Energy Information Administration
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Preface

Background

The *Cost and Quality of Fuels for Electric Utility Plants 2001* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy. This publication provides information concerning the quality, quantity, and cost of fossil fuels used by utility power plants to produce electricity in the United States.

Coverage of Sources

The information contained in this publication is compiled from data reported on the Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." The FERC Form 423 is a monthly survey that collects data from steam-electric and combined-cycle plants with a total generator nameplate capacity of 50 or more megawatts. Data for gas-turbines and internal combustion units are not collected on this survey, nor is their generating capacity used to determine the 50-megawatt threshold. The geographic coverage of the survey includes the contiguous United States, Alaska, Hawaii, and the District of Columbia. Data on nonutility power plants are not collected on this survey.

Understanding the effect of the restructuring of the electricity industry is important when reviewing data presented in this publication. Since January 1998, many electric utilities have sold their electric plants or spun them off into unregulated subsidiaries. Once a plant becomes the property of an unregulated entity, it is no longer required to file on the FERC Form 423 survey.

One of the most important effects of restructuring on data presented in this publication is the cost data. Restructuring has allowed many plants to stop reporting data on the FERC Form 423. In doing so, data at the State, Census Division, and National level have been affected by the elimination of respondents from the survey. Depending on the volume and price of fuel delivered to a specific plant, its removal from the database can substantially change the weighted average cost of fuel shown for a particular State. Data on the cost of fuel collected on this survey have historically been used by many industry participants as part of an index to adjust the price of fuel delivered under contracts. The use of these data should be reviewed to determine the effect that reclassification and subsequent removal of plants from the database have on the index.

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Summary Tables

Table ES1. Receipts of Fossil Fuels by Type of Fuel, 2000-2001

Type of Fuel	2001	2000	Difference	Percent Change
Total Coal (thousand short tons)	**762,815**	**790,274**	**-27,459**	**-3.5**
Bituminous	348,703	375,673	-26,970	-7.2
Subbituminous	349,340	341,242	8,098	2.4
Lignite	64,772	73,349	-8,576	-11.7
Anthracite[1]	—	11	-11	-100.0
Total Petroleum (thousand barrels)	**114,523**	**99,855**	**14,667**	**14.7**
Residual No. 6 Fuel Oil	104,791	92,417	12,374	13.4
Distillate (No. 2 Fuel Oil)	9,426	7,205	2,220	30.8
No. 4 and No. 5 Fuel Oil	257	231	25	11.0
Other Fuel Oils[2]	49	2	47	2350.0
Total Gas (million cubic feet)	**2,152,366**	**2,629,986**	**-477,620**	**-18.2**
Natural	2,148,924	2,618,199	-469,275	-17.9
Other[3]	3,442	11,787	-8,345	-70.8

1 Anthracite includes anthracite silt and culm delivered from off-site storage.
2 Other Fuel Oils include Jet Fuel, Kerosene, and Waste Oil.
3 Other Gas includes Blast Furnace, Coke Oven, and Refinery Gas.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table ES2. Average Delivered Cost of Fuels by Type of Purchase, 2000-2001

Type of Purchase	2001	2000	Difference	Percent Change
Total Coal (dollars per short ton)	**24.68**	**24.28**	**0.39**	**1.6**
Contract	23.67	24.15	-.48	-2.0
Spot	28.64	24.85	3.79	15.3
Total Petroleum (dollars per barrel)	**24.86**	**28.24**	**-3.38**	**-12.0**
Contract	24.66	28.50	-3.84	-13.5
Spot	25.02	27.94	-2.91	-10.4
Total Gas (dollars per Mcf)	**4.61**	**4.38**	**.22**	**5.0**
Firm Gas	4.50	4.37	.14	3.1
Interruptible Gas	4.45	4.19	25	61
Spot Purchase Gas	4.74	4.46	.28	6.2

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table ES3. Average Quality of Coal by State of Origin, 2000-2001

State of Origin	Btu (per pound)		Sulfur (percent by weight)		Sulfur (pounds per Million Btu)		Ash (percent by weight)	
	2001	2000	2001	2000	2001	2000	2001	2000
Alabama	12,136	12,222	1.15	1.07	0.95	0.87	12.74	12.59
Arizona	10,929	10,936	.51	.51	.47	.46	9.60	9.53
Colorado	11,068	11,096	.45	.46	.41	.41	8.46	8.31
Illinois	11,421	11,633	2.21	2.11	1.94	1.81	8.66	8.17
Indiana	11,077	11,115	2.12	2.22	1.91	1.99	9.03	8.95
Kansas	10,573	10,808	3.73	4.58	3.53	4.24	20.10	19.58
Kentucky	12,166	12,217	1.48	1.51	1.22	1.23	11.02	10.55
Louisiana	6,839	6,814	1.15	1.02	1.68	1.49	13.66	13.45
Maryland	11,970	12,140	1.69	1.81	1.41	1.49	17.38	16.21
Missouri	10,940	10,823	4.67	3.82	4.27	3.53	16.58	15.09
Montana	9,099	9,179	.49	.45	.54	.49	6.27	5.72
New Mexico	9,425	9,375	.68	.74	.73	.79	18.82	20.03
North Dakota	6,537	6,528	.74	.72	1.13	1.10	9.63	9.49
Ohio	11,693	11,798	3.23	3.22	2.77	2.73	10.81	10.50
Oklahoma	12,559	12,883	3.01	3.65	2.39	2.84	10.48	9.46
Pennsylvania	12,961	13,003	1.79	1.83	1.38	1.41	8.16	8.29
Tennessee	12,749	12,751	1.20	1.11	.94	.87	8.07	9.40
Texas	6,405	6,383	1.13	1.01	1.76	1.58	16.62	16.92
Utah	11,863	11,846	.52	.46	.44	.39	8.85	9.07
Virginia	12,750	12,891	.94	.93	.74	.72	10.58	9.84
Washington	—	7,765	—	.92	—	1.19	—	15.24
West Virginia	12,190	12,307	1.16	1.29	.95	1.05	12.58	11.57
Wyoming	8,689	8,697	.32	.31	.36	.36	5.29	5.23
Subtotal	**9,994**	**10,097**	**.89**	**.93**	**.89**	**.92**	**8.85**	**8.87**
Imported	11,855	12,035	.66	.63	.56	.53	6.71	5.65
Total	**10,019**	**10,115**	**.89**	**.93**	**.89**	**.91**	**8.82**	**8.84**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.• Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." .

Table ES4. Receipts of Coal by Rank, 1997-2001

Rank	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per Million Btu)	Ash (percent by weight)	(cents per Million Btu)	(dollars per short ton)
2001							
Total Coal (thousand short tons)	**762,815**	**10,019**	**0.89**	**0.89**	**8.82**	**123.15**	**24.68**
Bituminous	348,703	11,919	1.42	1.19	10.5	138.73	33.07
Subbituminous	349,340	8,780	.35	.39	6.2	103.92	18.25
Lignite	64,772	6,479	.98	1.52	13.9	109.45	14.18
Anthracite[1]	—	—	—	—	—	—	—
2000							
Total Coal (thousand short tons)	**790,274**	**10,115**	**.93**	**.91**	**8.84**	**120.04**	**24.28**
Bituminous	375,673	12,045	1.45	1.21	10.1	130.43	31.42
Subbituminous	341,242	8,778	.35	.40	6.3	108.41	19.03
Lignite	73,349	6,455	.91	1.41	14.2	94.25	12.17
Anthracite[1]	11	7,625	.64	.84	37.2	76.90	11.73
1999							
Total Coal (thousand short tons)	**908,232**	**10,163**	**1.01**	**.99**	**9.01**	**121.63**	**24.72**
Bituminous	444,399	12,064	1.57	1.30	10.2	131.38	31.70
Subbituminous	386,271	8,724	.38	.43	6.6	110.40	19.26
Lignite	77,425	6,434	.90	1.39	14.2	92.81	11.94
Anthracite[1]	137	7,509	.64	.86	37.8	52.64	7.91
1998							
Total Coal (thousand short tons)	**929,448**	**10,241**	**1.06**	**1.04**	**9.18**	**125.16**	**25.64**
Bituminous	478,252	12,033	1.61	1.34	10.5	134.56	32.38
Subbituminous	373,496	8,728	.38	.44	6.6	113.34	19.79
Lignite	77,189	6,471	.95	1.46	13.8	94.30	12.20
Anthracite[1]	511	7,479	.55	.74	37.6	90.08	13.47
1997							
Total Coal (thousand short tons)	**880,588**	**10,275**	**1.11**	**1.08**	**9.36**	**127.29**	**26.16**
Bituminous	466,104	12,017	1.65	1.38	10.5	135.00	32.45
Subbituminous	336,805	8,737	.40	.45	6.7	118.54	20.71
Lignite	76,928	6,478	.98	1.51	13.8	92.63	12.00
Anthracite[1]	751	7,511	.53	.71	36.7	102.47	15.39

[1] Anthracite includes anthracite silt and culm delivered from off-site storage.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Fossil-Fuel Data at the Census Division and State Level

Table 1. Receipts of Coal by Census Division and State, 1997-2001
(Thousand Short Tons)

	2001	2000	1999	1998	1997
New England	**1,710**	**1,842**	**1,764**	**5,538**	**7,125**
Connecticut	—	—	35	657	952
Maine	—	—	—	—	—
Massachusetts	—	324	394	3,473	4,545
New Hampshire	1,710	1,518	1,335	1,408	1,628
Rhode Island	—	—	—	—	—
Vermont	—	—	—	—	—
Middle Atlantic	**1,736**	**13,013**	**40,575**	**55,557**	**54,185**
New Jersey	214	1,825	2,597	2,312	2,087
New York	772	1,289	4,047	9,296	8,277
Pennsylvania	750	9,899	33,932	43,948	43,821
East North Central	**165,239**	**167,092**	**201,873**	**208,745**	**202,401**
Illinois	16,281	14,263	36,241	39,867	40,750
Indiana	51,840	51,494	56,933	57,091	53,353
Michigan	33,466	32,491	33,281	34,906	32,145
Ohio	39,764	46,680	51,568	53,442	52,743
Wisconsin	23,888	22,164	23,850	23,438	23,410
West North Central	**139,709**	**128,864**	**133,751**	**134,443**	**120,150**
Iowa	21,970	21,510	21,474	21,657	16,675
Kansas	21,286	19,276	19,553	18,445	16,672
Minnesota	18,059	17,717	16,559	17,915	17,591
Missouri	39,039	32,871	37,486	38,589	33,553
Nebraska	12,949	10,756	11,970	11,940	10,638
North Dakota	24,223	24,731	24,650	24,199	23,087
South Dakota	2,182	2,003	2,059	1,699	1,934
South Atlantic	**136,547**	**143,082**	**159,284**	**159,850**	**149,311**
Delaware	24	575	1,204	1,744	1,682
District of Columbia	—	R —	—	—	—
Florida	26,192	24,547	25,477	27,904	27,595
Georgia	34,362	35,623	33,296	31,748	28,346
Maryland	—	6,171	11,143	10,845	10,139
North Carolina	25,944	22,365	25,575	27,818	26,151
South Carolina	15,405	14,282	12,877	12,945	11,835
Virginia	10,825	R 12,660	12,932	12,716	11,930
West Virginia	23,795	26,857	36,780	34,130	31,633
East South Central	**94,071**	**97,352**	**99,586**	**100,791**	**102,352**
Alabama	29,866	32,099	30,192	30,920	30,378
Kentucky	33,844	32,247	35,435	36,962	39,550
Mississippi	6,123	5,293	6,423	5,886	6,043
Tennessee	24,238	27,713	27,537	27,023	26,381
West South Central	**125,473**	**135,798**	**151,343**	**144,195**	**135,858**
Arkansas	14,582	14,569	15,406	14,173	11,879
Louisiana	8,113	9,845	13,854	14,043	13,167
Oklahoma	17,118	18,375	20,999	19,747	18,378
Texas	85,660	93,009	101,084	96,231	92,435
Mountain	**95,747**	**99,360**	**112,242**	**112,208**	**103,539**
Arizona	19,297	18,974	19,712	18,826	16,788
Colorado	18,673	17,025	18,389	18,061	16,711
Idaho	—	—	—	—	—
Montana	307	317	10,417	10,520	9,160
Nevada	8,055	7,872	8,075	8,035	6,851
New Mexico	11,543	14,786	16,059	15,841	15,775
Utah	13,709	15,430	14,193	14,896	15,053
Wyoming	24,163	24,957	25,396	26,029	23,201
Pacific Contiguous	**2,583**	**3,871**	**7,812**	**8,120**	**5,667**
California	—	—	—	—	—
Oregon	2,583	2,000	2,326	2,014	875
Washington	—	1,871	5,486	6,106	4,792
Pacific Noncontiguous	—	—	—	—	—
Alaska	—	—	—	—	—
Hawaii	—	—	—	—	—
Total	**762,815**	**790,274**	**908,232**	**929,448**	**880,588**

R Revised.

Notes: • Totals may not equal sum of components because of independent rounding. • Coal includes anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal. Includes Imported Coal. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table 2. Average Delivered Cost of Coal by Census Division and State, 1997-2001

	2001		2000		1999		1998		1997	
	(cents per million Btu)	(dollars per short ton)	(cents per million Btu)	(dollars per short ton)	(cents per million Btu)	(dollars per short ton)	(cents per million Btu)	(dollars per short ton)	(cents per million Btu)	(dollars per short ton)
New England	**167.22**	**43.52**	**153.06**	**40.16**	**156.75**	**41.22**	**167.60**	**42.94**	**171.18**	**43.67**
Connecticut	—	—	—	—	169.29	45.85	181.11	47.59	190.47	50.02
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	174.65	45.89	173.39	45.63	167.63	42.30	169.91	42.72
New Hampshire	167.22	43.52	148.45	38.94	151.50	39.79	161.22	42.35	163.23	42.62
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**143.07**	**37.14**	**121.90**	**31.16**	**132.46**	**33.48**	**137.57**	**34.33**	**138.26**	**34.39**
New Jersey	227.37	58.58	139.36	36.66	145.37	38.23	159.03	41.71	175.58	45.94
New York	141.60	37.06	149.06	39.11	144.91	37.77	143.44	37.44	142.38	37.32
Pennsylvania	120.63	31.12	114.90	29.11	129.89	32.61	135.05	33.28	135.53	33.28
East North Central	**120.45**	**25.25**	**123.81**	**26.35**	**125.92**	**26.60**	**129.91**	**27.51**	**130.73**	**27.68**
Illinois	119.16	23.01	115.09	22.31	143.68	27.47	155.75	30.22	155.44	30.41
Indiana	113.66	23.91	108.03	22.91	111.04	23.58	112.33	23.63	116.39	24.35
Michigan	127.48	26.06	130.38	27.18	130.61	27.39	133.43	28.19	136.90	28.93
Ohio	130.96	30.97	145.70	34.45	136.23	32.47	136.48	32.52	132.07	31.41
Wisconsin	104.64	19.06	101.70	18.64	102.35	18.66	107.37	19.97	108.95	20.43
West North Central	**89.14**	**14.97**	**88.02**	**14.69**	**87.32**	**14.58**	**88.91**	**14.91**	**91.67**	**15.39**
Iowa	81.36	14.09	81.63	14.08	82.12	14.09	87.56	15.12	93.66	16.23
Kansas	104.76	18.20	98.47	17.08	95.42	16.47	98.10	17.06	102.13	17.91
Minnesota	101.78	18.13	111.06	19.83	109.57	19.47	106.94	19.00	109.47	19.47
Missouri	95.76	17.08	91.77	16.36	92.56	16.56	91.71	16.40	93.40	16.80
Nebraska	56.57	9.71	55.97	9.66	55.44	9.42	58.64	10.07	58.51	10.06
North Dakota	74.15	9.74	72.40	9.45	73.04	9.56	76.20	10.01	77.82	10.21
South Dakota	103.27	17.41	99.34	16.81	93.64	16.16	92.73	16.19	92.01	15.99
South Atlantic	**157.08**	**38.21**	**141.98**	**34.81**	**141.12**	**34.84**	**144.70**	**35.58**	**147.58**	**36.34**
Delaware	216.91	54.54	152.14	39.54	158.94	41.12	156.30	40.52	157.14	41.05
District of Columbia	—	—	R —	R —	—	—	—	—	—	—
Florida	171.81	41.74	156.90	38.69	158.86	39.08	164.81	40.03	172.50	41.82
Georgia	166.07	39.04	154.21	35.65	154.56	36.29	154.53	36.31	158.56	37.28
Maryland	—	—	133.04	34.44	137.89	35.69	145.68	37.63	150.03	38.75
North Carolina	159.30	39.20	142.70	35.53	143.76	35.80	143.81	35.66	142.92	35.35
South Carolina	156.52	39.40	138.96	35.37	141.64	36.29	144.68	37.05	144.73	37.21
Virginia	159.32	40.29	R 133.09	R 34.12	134.27	34.11	137.80	34.73	139.33	34.98
West Virginia	125.02	30.31	120.41	29.57	118.19	29.22	122.15	30.06	123.72	30.68
East South Central	**126.35**	**28.61**	**119.73**	**27.28**	**123.20**	**28.03**	**126.04**	**29.10**	**123.89**	**28.70**
Alabama	141.07	30.61	140.98	30.88	147.60	32.36	157.47	36.28	153.58	35.58
Kentucky	110.36	25.29	102.29	23.74	105.84	24.52	105.90	24.52	104.59	24.20
Mississippi	163.46	38.31	152.24	35.16	155.23	34.34	153.82	32.51	154.68	32.44
Tennessee	121.98	28.31	110.63	25.73	113.12	26.32	112.49	26.39	112.47	26.67
West South Central	**120.86**	**19.17**	**121.42**	**19.08**	**120.36**	**18.86**	**123.37**	**19.34**	**126.75**	**19.69**
Arkansas	87.46	15.23	142.13	24.68	145.60	25.19	147.19	25.53	163.98	28.56
Louisiana	130.89	20.64	131.99	20.94	139.82	22.79	142.93	23.15	147.93	23.97
Oklahoma	90.57	15.75	94.32	16.46	91.24	15.73	90.97	15.74	91.84	15.87
Texas	133.24	20.39	122.71	18.53	119.97	18.01	123.90	18.61	125.92	18.69
Mountain	**108.34**	**21.49**	**106.31**	**21.13**	**106.06**	**20.69**	**107.26**	**20.83**	**110.65**	**21.52**
Arizona	124.97	25.43	123.80	25.33	132.66	27.21	133.10	27.12	142.47	28.95
Colorado	92.19	17.93	92.56	18.14	98.49	19.20	98.68	19.41	100.95	19.93
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	94.93	12.42	91.53	12.12	72.68	12.26	67.38	11.36	68.34	11.52
Nevada	126.19	28.35	126.39	28.34	129.37	29.13	129.81	29.07	139.21	31.10
New Mexico	147.38	27.43	137.83	25.38	132.90	24.27	130.59	23.72	133.59	24.23
Utah	112.30	25.96	101.31	23.66	103.09	23.96	114.83	25.97	111.28	25.22
Wyoming	76.74	13.56	77.93	13.72	76.21	13.39	78.63	13.83	80.56	14.16
Pacific Contiguous	**110.99**	**19.33**	**136.19**	**23.09**	**140.77**	**23.77**	**138.44**	**23.07**	**154.48**	**25.19**
California	—	—	—	—	—	—	—	—	—	—
Oregon	110.99	19.33	106.84	18.45	107.89	19.34	108.91	18.92	113.91	19.95
Washington	—	—	168.79	28.05	155.96	25.65	148.73	24.44	162.55	26.15
Pacific Noncontiguous	—	—	—	—	—	—	—	—	—	—
Alaska	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—
Total	**123.15**	**24.68**	**120.04**	**24.28**	**121.63**	**24.72**	**125.16**	**25.64**	**127.29**	**26.16**

R Revised.

Notes: • Totals may not equal sum of components because of independent rounding. • Coal includes anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal. Includes Imported Coal. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table 3. Receipts and Average Delivered Cost of Coal by Type of Purchase, Mine Type, Census Division and State, 2001

Census Division and State	Type of Purchase						Mine Type					
	Contract			Spot			Surface			Underground		
	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)
New England	**892**	**163.66**	**43.02**	**818**	**171.18**	**44.07**	**593**	**171.66**	**43.64**	**1,117**	**164.95**	**43.46**
Connecticut	—	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—	—	—
New Hampshire	892	163.66	43.02	818	171.18	44.07	593	171.66	43.64	1,117	164.95	43.46
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**1,179**	**125.13**	**32.57**	**557**	**181.41**	**46.82**	**79**	**147.57**	**37.03**	**1,657**	**142.87**	**37.15**
New Jersey	67	177.73	46.22	147	250.30	64.21	—	—	—	214	227.37	58.58
New York	396	133.09	35.20	376	150.77	39.02	76	144.20	36.26	696	141.33	37.15
Pennsylvania	716	115.65	29.85	34	225.90	57.97	3	237.94	56.54	747	120.19	31.02
East North Central	**124,844**	**119.01**	**24.86**	**40,396**	**124.83**	**26.47**	**120,055**	**114.36**	**22.79**	**45,184**	**134.04**	**31.79**
Illinois	10,750	115.47	22.41	5,531	126.44	24.17	10,024	97.43	17.61	6,256	148.75	31.65
Indiana	44,937	111.36	23.22	6,903	127.66	28.42	36,927	107.35	21.65	14,913	127.23	29.51
Michigan	27,083	127.11	26.01	6,383	129.09	26.26	26,724	123.86	23.70	6,742	138.21	35.41
Ohio	25,301	133.64	31.79	14,463	126.19	29.52	24,727	131.15	30.53	15,037	130.66	31.68
Wisconsin	16,773	101.40	18.50	7,115	112.31	20.38	21,653	97.97	17.18	2,235	150.35	37.24
West North Central	**113,520**	**88.38**	**14.65**	**26,189**	**92.24**	**16.35**	**136,962**	**87.62**	**14.59**	**2,747**	**142.52**	**33.62**
Iowa	15,708	79.36	13.67	6,262	86.30	15.14	21,545	79.64	13.69	425	145.62	34.10
Kansas	16,586	105.46	17.85	4,700	102.55	19.42	20,483	102.11	17.53	803	155.95	35.32
Minnesota	17,541	100.98	17.97	518	127.87	23.71	17,939	101.00	17.95	120	186.94	45.31
Missouri	27,936	94.22	16.92	11,103	99.73	17.47	37,641	93.99	16.54	1,398	130.52	31.50
Nebraska	9,343	55.84	9.63	3,606	58.49	9.92	12,949	56.57	9.71	—	—	—
North Dakota	24,223	74.15	9.74	—	—	—	24,223	74.15	9.74	—	—	—
South Dakota	2,182	103.27	17.41	—	—	—	2,182	103.27	17.41	—	—	—
South Atlantic[1]	**89,437**	**150.69**	**37.29**	**47,110**	**169.83**	**39.95**	**64,633**	**156.11**	**37.10**	**71,914**	**157.91**	**39.20**
Delaware	14	195.00	49.30	10	248.18	61.91	—	—	—	24	216.91	54.54
District of Columbia	—	—	—	—	—	—	—	—	—	—	—	—
Florida[1]	15,244	168.21	41.32	10,948	176.97	42.32	7,828	172.44	41.13	18,364	171.55	41.99
Georgia	17,966	164.80	41.42	16,396	167.68	36.44	22,600	159.60	36.32	11,762	177.40	44.26
Maryland	—	—	—	—	—	—	—	—	—	—	—	—
North Carolina	19,780	152.03	37.38	6,164	182.55	45.02	16,201	158.10	38.87	9,743	161.28	39.74
South Carolina	10,545	148.97	37.64	4,860	173.11	43.23	3,021	156.60	39.12	12,384	156.51	39.47
Virginia	6,900	142.04	35.79	3,926	189.40	48.19	2,256	167.86	42.83	8,569	157.05	39.62
West Virginia	18,987	125.41	30.39	4,808	123.49	30.01	12,727	135.17	32.25	11,068	113.75	28.08
East South Central[1]	**77,031**	**123.19**	**27.75**	**17,040**	**140.24**	**32.50**	**44,632**	**123.34**	**26.60**	**49,439**	**128.83**	**30.42**
Alabama[1]	27,417	139.04	29.92	2,449	161.67	38.31	15,861	129.75	26.52	14,005	152.40	35.25
Kentucky[1]	23,445	104.74	23.96	10,399	122.94	28.31	18,564	112.67	25.52	15,280	107.63	25.02
Mississippi	4,240	154.30	36.54	1,883	184.80	42.28	2,177	167.49	38.79	3,946	161.27	38.04
Tennessee[1]	21,929	118.10	27.37	2,310	158.27	37.22	8,030	124.45	25.96	16,208	120.93	29.48
West South Central	**115,754**	**121.12**	**19.08**	**9,718**	**118.03**	**20.30**	**125,301**	**120.80**	**19.15**	**172**	**148.92**	**36.16**
Arkansas	13,130	82.12	14.35	1,452	137.37	23.22	14,582	87.46	15.23	—	—	—
Louisiana	8,113	130.89	20.64	—	—	—	8,113	130.89	20.64	—	—	—
Oklahoma	16,893	90.60	15.76	225	88.26	14.91	17,118	90.57	15.75	—	—	—
Texas	77,618	135.34	20.43	8,041	115.42	19.92	85,488	133.19	20.35	172	148.92	36.16
Mountain	**85,144**	**109.98**	**21.85**	**10,603**	**94.94**	**18.62**	**75,239**	**106.67**	**20.23**	**20,508**	**113.37**	**26.14**
Arizona	17,193	123.84	25.34	2,104	134.69	26.15	19,030	124.17	25.23	267	176.14	39.76
Colorado	15,040	93.08	17.90	3,633	88.72	18.09	15,236	90.58	16.98	3,437	98.10	22.17
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	307	94.93	12.42	—	—	—	307	94.93	12.42	—	—	—
Nevada	6,455	128.41	28.65	1,599	117.51	27.13	4,960	124.15	27.20	3,095	129.25	30.17
New Mexico	11,543	147.38	27.43	—	—	—	11,543	147.38	27.43	—	—	—
Utah	13,527	112.54	26.01	182	94.96	22.40	—	—	—	13,709	112.30	25.96
Wyoming	21,079	79.55	14.15	3,084	56.43	9.48	24,163	76.74	13.56	—	—	—
Pacific Contiguous	—	—	—	**2,583**	**110.99**	**19.33**	**2,517**	**111.28**	**19.17**	**66**	**103.20**	**25.18**
California	—	—	—	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	2,583	110.99	19.33	2,517	111.28	19.17	66	103.20	25.18
Washington	—	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	—	—	—	—	—	—	—	—	—	—	—	—
Alaska	—	—	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—	—	—
Total	**607,801**	**119.81**	**23.67**	**155,014**	**135.39**	**28.64**	**570,012**	**115.71**	**21.61**	**192,803**	**140.21**	**33.75**

[1] The cost of coal shown for the States of Alabama, Florida, Kentucky, and Tennessee is not the total delivered cost of coal to these States and their respective Census Divisions. For more detailed information see footnotes 3, 4, and 5 at the end of Table 31.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Cost = average delivered cost.

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

Table 4. Receipts and Average Delivered Cost of Coal by Rank, Census Division, and State, 2001

Census Division and State	Bituminous[1]			Subbituminous			Lignite			Total		
	Receipts (1,000 short tons)	Heat Value (Btu per pound)	Cost (cents per Million Btu)	Receipts (1,000 short tons)	Heat Value (Btu per pound)	Cost (cents per Million Btu)	Receipts (1,000 short tons)	Heat Value (Btu per pound)	Cost (cents per Million Btu)	Receipts (1,000 short tons)	Heat Value (Btu per pound)	Cost (cents per Million Btu)
New England	**1,710**	**13,013**	**167.22**	—	—	—	—	—	—	**1,710**	**13,013**	**167.22**
Connecticut	—	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—	—	—
New Hampshire	1,710	13,013	167.22	—	—	—	—	—	—	1,710	13,013	167.22
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**1,736**	**12,981**	**143.07**	—	—	—	—	—	—	**1,736**	**12,981**	**143.07**
New Jersey	214	12,883	227.37	—	—	—	—	—	—	214	12,883	227.37
New York	772	13,086	141.60	—	—	—	—	—	—	772	13,086	141.60
Pennsylvania	750	12,900	120.63	—	—	—	—	—	—	750	12,900	120.63
East North Central	**96,053**	**11,656**	**128.32**	**69,186**	**8,854**	**106.07**	—	—	—	**165,239**	**10,483**	**120.45**
Illinois	7,523	10,628	140.66	8,758	8,816	96.90	—	—	—	16,281	9,654	119.16
Indiana	35,691	11,299	114.65	16,149	8,792	110.85	—	—	—	51,840	10,518	113.66
Michigan	10,793	12,665	147.16	22,673	9,056	114.38	—	—	—	33,466	10,220	127.48
Ohio	39,267	11,861	130.80	496	8,779	147.62	—	—	—	39,764	11,823	130.96
Wisconsin	2,778	12,192	151.80	21,110	8,702	95.94	—	—	—	23,888	9,108	104.64
West North Central	**4,941**	**11,379**	**138.55**	**111,088**	**8,658**	**88.63**	**23,679**	**6,537**	**74.36**	**139,709**	**8,395**	**89.14**
Iowa	957	11,288	131.19	21,013	8,539	78.37	—	—	—	21,970	8,658	81.36
Kansas	1,664	10,992	146.46	19,621	8,490	100.18	—	—	—	21,286	8,686	104.76
Minnesota	191	11,655	184.21	17,868	8,879	100.62	—	—	—	18,059	8,909	101.78
Missouri	2,129	11,696	131.85	36,910	8,758	92.98	—	—	—	39,039	8,918	95.76
Nebraska	—	—	—	12,949	8,586	56.57	—	—	—	12,949	8,586	56.57
North Dakota	—	—	—	544	8,026	66.72	23,679	6,537	74.36	24,223	6,570	74.15
South Dakota	—	—	—	2,182	8,427	103.27	—	—	—	2,182	8,427	103.27
South Atlantic[2]	**128,706**	**12,368**	**157.17**	**7,841**	**8,783**	**154.88**	—	—	—	**136,547**	**12,162**	**157.08**
Delaware	24	12,572	216.91	—	—	—	—	—	—	24	12,572	216.91
District of Columbia	—	—	—	—	—	—	—	—	—	—	—	—
Florida[2]	25,559	12,230	172.30	633	8,733	144.29	—	—	—	26,192	12,146	171.81
Georgia	27,782	12,458	167.50	6,579	8,783	157.46	—	—	—	34,362	11,754	166.07
Maryland	—	—	—	—	—	—	—	—	—	—	—	—
North Carolina	25,944	12,303	159.30	—	—	—	—	—	—	25,944	12,303	159.30
South Carolina	15,405	12,586	156.52	—	—	—	—	—	—	15,405	12,586	156.52
Virginia	10,825	12,643	159.32	—	—	—	—	—	—	10,825	12,643	159.32
West Virginia	23,166	12,212	124.76	629	8,841	138.64	—	—	—	23,795	12,123	125.02
East South Central[2]	**77,404**	**11,864**	**129.19**	**16,667**	**8,795**	**108.54**	—	—	—	**94,071**	**11,320**	**126.35**
Alabama[2]	19,295	11,973	153.21	10,571	8,800	110.92	—	—	—	29,866	10,850	141.07
Kentucky[2]	32,164	11,602	110.45	1,680	8,739	108.03	—	—	—	33,844	11,460	110.36
Mississippi	6,069	11,744	163.57	54	8,768	146.20	—	—	—	6,123	11,718	163.46
Tennessee[2]	19,876	12,220	125.06	4,362	8,804	102.52	—	—	—	24,238	11,605	121.98
West South Central	**977**	**10,783**	**143.29**	**83,709**	**8,622**	**117.12**	**40,787**	**6,445**	**130.23**	**125,473**	**7,931**	**120.86**
Arkansas	—	—	—	14,582	8,708	87.46	—	—	—	14,582	8,708	87.46
Louisiana	—	—	—	4,359	8,786	123.66	3,754	6,839	141.66	8,113	7,885	130.89
Oklahoma	—	—	—	17,118	8,695	90.57	—	—	—	17,118	8,695	90.57
Texas	977	10,783	143.29	47,650	8,555	135.45	37,032	6,405	128.99	85,660	7,651	133.24
Mountain	**36,864**	**11,150**	**115.28**	**58,576**	**9,163**	**103.07**	**307**	**6,539**	**94.93**	**95,747**	**9,920**	**108.34**
Arizona	6,165	10,896	127.36	13,131	9,837	123.72	—	—	—	19,297	10,175	124.97
Colorado	6,669	10,879	102.77	12,005	9,085	85.15	—	—	—	18,673	9,726	92.19
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	—	—	—	—	—	—	307	6,539	94.93	307	6,539	94.93
Nevada	8,055	11,232	126.19	—	—	—	—	—	—	8,055	11,232	126.19
New Mexico	—	—	—	11,543	9,308	147.38	—	—	—	11,543	9,308	147.38
Utah	13,709	11,559	112.30	—	—	—	—	—	—	13,709	11,559	112.30
Wyoming	2,266	9,883	96.60	21,897	8,724	74.42	—	—	—	24,163	8,833	76.74
Pacific Contiguous	**311**	**11,880**	**115.89**	**2,272**	**8,272**	**110.03**	—	—	—	**2,583**	**8,706**	**110.99**
California	—	—	—	—	—	—	—	—	—	—	—	—
Oregon	311	11,880	115.89	2,272	8,272	110.03	—	—	—	2,583	8,706	110.99
Washington	—	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	—	—	—	—	—	—	—	—	—	—	—	—
Alaska	—	—	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—	—	—
Total	**348,703**	**11,919**	**138.73**	**349,340**	**8,780**	**103.92**	**64,772**	**6,479**	**109.45**	**762,815**	**10,019**	**123.15**

1 Includes 11 thousand short tons of anthracite coal delivered to Pennsylvania.
2 The cost of coal shown for the States of Alabama, Florida, Kentucky, and Tennessee is not the total delivered cost of coal to these States and their respective Census Divisions. For more detailed information see footnotes 3, 4, and 5 at the end of Table 31.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Cost = average delivered cost.

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

Table 5. Receipts and Average Delivered Cost of Coal by Sulfur Content, Census Division, and State, 2001

Census Division and State	0.5% or Less			More than 0.5% up to 1.0%			More than 1.0% up to 1.5%		
	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)
New England	**18**	**173.18**	**38.96**	**646**	**173.47**	**44.61**	**245**	**174.13**	**45.64**
Connecticut	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—
New Hampshire	18	173.18	38.96	646	173.47	44.61	245	174.13	45.64
Rhode Island	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—
Middle Atlantic	**10**	**279.00**	**70.51**	**174**	**220.49**	**56.51**	**77**	**149.34**	**38.98**
New Jersey	10	279.00	70.51	95	242.37	61.03	—	—	—
New York	—	—	—	48	176.19	46.49	66	149.43	38.93
Pennsylvania	—	—	—	31	224.82	58.11	11	148.80	39.31
East North Central	**70,103**	**107.48**	**19.17**	**33,845**	**139.10**	**32.85**	**14,795**	**124.25**	**28.43**
Illinois	8,778	97.09	17.13	2,893	131.10	26.97	660	142.85	31.39
Indiana	16,920	113.20	20.18	6,842	136.77	32.13	9,355	115.35	25.37
Michigan	21,971	114.33	20.71	7,546	155.73	37.97	2,078	129.17	33.25
Ohio	487	148.75	26.19	16,290	132.71	31.64	1,688	144.30	33.87
Wisconsin	21,947	99.23	17.50	274	180.30	43.69	1,013	144.30	35.77
West North Central	**101,480**	**88.85**	**15.51**	**33,428**	**87.08**	**12.76**	**3,370**	**93.56**	**14.58**
Iowa	20,895	79.61	13.70	847	104.56	19.16	28	193.43	45.58
Kansas	20,805	103.33	17.84	121	255.56	57.05	—	—	—
Minnesota	9,755	99.53	17.90	8,212	103.33	18.13	92	179.00	43.37
Missouri	34,348	93.92	16.65	3,349	93.54	15.76	470	138.14	32.95
Nebraska	12,949	56.57	9.71	—	—	—	—	—	—
North Dakota	544	66.72	10.71	20,899	74.42	9.65	2,780	73.91	10.22
South Dakota	2,182	103.27	17.41	—	—	—	—	—	—
South Atlantic[1]	**8,412**	**157.05**	**28.16**	**72,630**	**159.62**	**39.39**	**37,609**	**156.61**	**39.23**
Delaware	—	—	—	24	216.91	54.54	—	—	—
District of Columbia	—	—	—	—	—	—	—	—	—
Florida[1]	882	158.65	30.04	9,267	186.23	45.95	7,039	162.96	40.54
Georgia	6,628	158.10	27.82	18,506	170.54	42.47	8,022	160.81	40.06
Maryland	—	—	—	—	—	—	—	—	—
North Carolina	88	190.01	48.53	19,930	156.60	38.46	5,888	167.82	41.54
South Carolina	184	152.27	33.83	4,114	158.80	39.52	10,123	153.74	38.95
Virginia	—	—	—	6,678	161.24	40.79	3,201	160.51	40.99
West Virginia	629	138.64	24.52	14,110	130.72	31.63	3,335	118.57	29.59
East South Central[1]	**22,302**	**120.57**	**23.01**	**29,380**	**147.58**	**35.63**	**10,810**	**132.37**	**32.07**
Alabama[1]	10,903	110.56	19.57	9,651	173.84	41.83	4,109	135.31	32.57
Kentucky[1]	3,958	128.18	27.04	8,858	124.72	30.09	2,750	123.16	29.40
Mississippi	1,505	173.50	39.75	3,902	161.57	37.88	627	153.99	37.77
Tennessee[1]	5,936	115.96	22.39	6,970	133.06	32.81	3,324	132.15	32.59
West South Central	**85,371**	**117.73**	**20.28**	**14,141**	**142.68**	**18.42**	**21,536**	**123.51**	**16.46**
Arkansas	14,582	87.46	15.23	—	—	—	—	—	—
Louisiana	4,359	123.66	21.73	951	127.82	17.78	2,803	146.47	19.92
Oklahoma	17,118	90.57	15.75	—	—	—	—	—	—
Texas	49,312	135.90	23.22	13,189	143.84	18.46	18,733	119.99	15.94
Mountain	**55,958**	**99.25**	**19.67**	**37,988**	**122.27**	**24.08**	**1,801**	**100.09**	**23.45**
Arizona	6,592	130.77	26.26	12,705	122.01	25.00	—	—	—
Colorado	17,290	91.34	17.59	1,218	98.39	21.57	165	126.42	26.58
Idaho	—	—	—	—	—	—	—	—	—
Montana	95	95.26	12.43	211	94.79	12.41	—	—	—
Nevada	6,622	126.18	28.05	1,079	135.43	31.00	353	100.91	25.72
New Mexico	431	208.40	39.96	11,112	144.93	26.95	—	—	—
Utah	10,567	115.72	26.35	2,360	105.68	25.26	781	89.77	22.87
Wyoming	14,360	57.19	9.81	9,301	102.99	18.90	502	110.96	21.72
Pacific Contiguous	**2,272**	**110.03**	**18.20**	**311**	**115.89**	**27.54**	—	—	—
California	—	—	—	—	—	—	—	—	—
Oregon	2,272	110.03	18.20	311	115.89	27.54	—	—	—
Washington	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	—	—	—	—	—	—	—	—	—
Alaska	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—
Total	**345,927**	**105.25**	**18.91**	**222,542**	**140.39**	**29.96**	**90,243**	**139.85**	**29.95**

[1] The cost of coal shown for the States of Alabama, Florida, Kentucky, and Tennessee is not the total delivered cost of coal to these States and their respective Census Divisions. For more detailed information see footnotes 3, 4, and 5 at the end of Table 31.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Cost = average delivered cost.

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

Table 5. Receipts and Average Delivered Cost of Coal by Sulfur Content, Census Division, and State, 2001 (Continued)

Census Division and State	More than 1.5% up to 2.0%			More than 2.0% up to 3.0%			More than 3.0%			All Receipts Cost	
	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	Receipts (1,000 short tons)	Cost (cents per Million Btu)	Cost ($ per short ton)	(cents per Million Btu)	($ per short ton)
New England	**537**	**163.36**	**42.80**	**263**	**153.39**	**40.66**	—	—	—	**167.22**	**43.52**
Connecticut	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—	—
New Hampshire	537	163.36	42.80	263	153.39	40.66	—	—	—	167.22	43.52
Rhode Island	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**338**	**131.03**	**34.06**	**1,137**	**133.38**	**34.68**	—	—	—	**143.07**	**37.14**
New Jersey	—	—	—	108	210.11	55.31	—	—	—	227.37	58.58
New York	273	131.54	34.28	386	143.03	37.53	—	—	—	141.60	37.06
Pennsylvania	66	128.88	33.11	642	114.25	29.47	—	—	—	120.63	31.12
East North Central	**6,958**	**126.44**	**29.67**	**19,064**	**107.78**	**25.11**	**20,473**	**130.43**	**29.87**	**120.45**	**25.25**
Illinois	487	161.51	37.54	600	106.62	23.39	2,862	152.76	32.54	119.16	23.01
Indiana	2,687	110.68	24.54	11,358	103.49	23.59	4,677	102.96	22.86	113.66	23.91
Michigan	1,002	126.01	32.87	674	126.36	32.76	196	129.28	32.77	127.48	26.06
Ohio	2,135	133.25	31.30	6,424	112.74	27.09	12,738	135.43	31.80	130.96	30.97
Wisconsin	647	139.54	34.65	8	278.32	74.40	—	—	—	104.64	19.06
West North Central	**66**	**154.50**	**37.78**	**890**	**132.34**	**30.12**	**475**	**119.89**	**26.15**	**89.14**	**14.97**
Iowa	20	188.03	48.50	91	117.60	26.36	89	116.12	26.20	81.36	14.09
Kansas	—	—	—	6	110.20	28.77	354	118.81	25.71	104.76	18.20
Minnesota	—	—	—	—	—	—	—	—	—	101.78	18.13
Missouri	46	139.04	33.20	793	134.19	30.57	33	142.02	30.78	95.76	17.08
Nebraska	—	—	—	—	—	—	—	—	—	56.57	9.71
North Dakota	—	—	—	—	—	—	—	—	—	74.15	9.74
South Dakota	—	—	—	—	—	—	—	—	—	103.27	17.41
South Atlantic[1]	**7,472**	**139.61**	**34.96**	**5,833**	**164.10**	**39.01**	**4,590**	**140.61**	**33.77**	**157.08**	**38.21**
Delaware	—	—	—	—	—	—	—	—	—	216.91	54.54
District of Columbia	—	—	—	—	—	—	—	—	—	—	—
Florida[1]	1,215	157.61	39.73	5,067	167.41	39.76	2,721	163.18	38.85	171.81	41.74
Georgia	744	169.09	42.46	462	154.39	39.12	—	—	—	166.07	39.04
Maryland	—	—	—	—	—	—	—	—	—	—	—
North Carolina	37	167.91	42.91	—	—	—	—	—	—	159.30	39.20
South Carolina	928	175.60	44.33	56	194.05	48.57	—	—	—	156.52	39.40
Virginia	672	154.86	40.39	198	99.17	19.99	75	90.52	17.95	159.32	40.29
West Virginia	3,877	116.27	28.77	50	110.61	27.22	1,794	109.03	26.72	125.02	30.31
East South Central[1]	**5,656**	**131.97**	**31.91**	**10,422**	**107.11**	**25.53**	**15,502**	**97.15**	**21.81**	**126.35**	**28.61**
Alabama[1]	3,151	136.95	33.04	593	127.18	30.40	1,460	122.06	28.25	141.07	30.61
Kentucky[1]	1,294	124.77	29.96	3,858	104.24	24.27	13,126	92.23	20.51	110.36	25.29
Mississippi	76	151.33	36.46	11	142.25	36.10	2	150.30	37.99	163.46	38.31
Tennessee[1]	1,135	125.14	30.68	5,960	106.87	25.85	915	123.88	30.10	121.98	28.31
West South Central	**1,753**	**166.83**	**21.02**	**2,673**	**79.65**	**8.28**	—	—	—	**120.86**	**19.17**
Arkansas	—	—	—	—	—	—	—	—	—	87.46	15.23
Louisiana	—	—	—	—	—	—	—	—	—	130.89	20.64
Oklahoma	—	—	—	—	—	—	—	—	—	90.57	15.75
Texas	1,753	166.83	21.02	2,673	79.65	8.28	—	—	—	133.24	20.39
Mountain	—	—	—	—	—	—	—	—	—	**108.34**	**21.49**
Arizona	—	—	—	—	—	—	—	—	—	124.97	25.43
Colorado	—	—	—	—	—	—	—	—	—	92.19	17.93
Idaho	—	—	—	—	—	—	—	—	—	—	—
Montana	—	—	—	—	—	—	—	—	—	94.93	12.42
Nevada	—	—	—	—	—	—	—	—	—	126.19	28.35
New Mexico	—	—	—	—	—	—	—	—	—	147.38	27.43
Utah	—	—	—	—	—	—	—	—	—	112.30	25.96
Wyoming	—	—	—	—	—	—	—	—	—	76.74	13.56
Pacific Contiguous	—	—	—	—	—	—	—	—	—	**110.99**	**19.33**
California	—	—	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	—	—	—	—	—	—	110.99	19.33
Washington	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	—	—	—	—	—	—	—	—	—	—	—
Alaska	—	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—	—
Total	**22,780**	**135.28**	**31.69**	**40,282**	**116.99**	**26.60**	**41,040**	**119.16**	**27.22**	**123.15**	**24.68**

1 The cost of coal shown for the States of Alabama, Florida, Kentucky, and Tennessee is not the total delivered cost of coal to these States and their respective Census Divisions. For more detailed information see footnotes 3, 4, and 5 at the end of Table 31.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Cost = average delivered cost.

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

Table 6. Receipts of Petroleum by Census Division and State, 1997-2001
(Thousand Barrels)

	2001	2000	1999	1998	1997
New England	**1,099**	**758**	**13,621**	**35,559**	**36,176**
Connecticut	—	—	9,756	14,192	13,901
Maine	—	—	1,045	3,204	2,335
Massachusetts	165	87	205	15,733	18,344
New Hampshire	934	594	2,615	2,427	1,594
Rhode Island	—	—	—	—	—
Vermont	—	77	—	4	2
Middle Atlantic	**15,867**	**19,644**	**25,624**	**31,908**	**19,139**
New Jersey	64	776	2,437	1,781	1,516
New York	15,164	16,740	18,477	22,928	14,556
Pennsylvania	638	2,127	4,709	7,199	3,067
East North Central	**3,410**	**2,638**	**4,586**	**4,691**	**3,108**
Illinois	185	79	771	1,241	895
Indiana	311	360	665	500	390
Michigan	2,248	1,552	2,367	2,418	1,288
Ohio	548	596	739	491	467
Wisconsin	118	51	44	41	67
West North Central	**1,940**	**1,050**	**738**	**659**	**976**
Iowa	153	67	159	121	88
Kansas	1,546	571	356	248	490
Minnesota	41	36	42	45	39
Missouri	138	323	116	158	202
Nebraska	11	9	15	15	21
North Dakota	51	45	50	72	134
South Dakota	—	—	—	—	—
South Atlantic	**66,987**	**55,375**	**69,006**	**74,512**	**44,613**
Delaware	471	394	2,071	2,116	1,706
District of Columbia	—	183	412	446	139
Florida	57,951	47,323	54,285	59,824	38,320
Georgia	323	452	575	738	279
Maryland	—	1,029	6,675	6,005	1,985
North Carolina	439	343	497	406	350
South Carolina	138	115	93	109	137
Virginia	7,291	5,212	4,024	4,543	1,361
West Virginia	374	324	374	324	336
East South Central	**8,814**	**4,971**	**5,717**	**8,851**	**4,697**
Alabama	93	159	170	112	218
Kentucky	158	173	212	208	237
Mississippi	8,466	4,579	4,982	8,379	4,081
Tennessee	97	60	352	152	161
West South Central	**4,688**	**1,392**	**942**	**1,607**	**1,458**
Arkansas	85	61	109	90	73
Louisiana	2,331	591	636	1,264	846
Oklahoma	242	74	10	7	39
Texas	2,031	666	187	246	500
Mountain	**675**	**565**	**364**	**364**	**363**
Arizona	480	324	127	144	123
Colorado	43	64	7	—	—
Idaho	—	—	—	—	—
Montana	—	—	20	14	16
Nevada	9	17	20	30	38
New Mexico	29	51	65	53	45
Utah	49	39	42	42	23
Wyoming	65	70	84	81	117
Pacific Contiguous	**782**	**125**	**65**	**124**	**33**
California	445	27	10	103	—
Oregon	337	93	42	6	17
Washington	—	5	13	15	15
Pacific Noncontiguous	**10,262**	**13,339**	**10,744**	**6,916**	**7,227**
Alaska	—	—	—	—	—
Hawaii	10,262	13,339	10,744	6,916	7,227
Total	**114,523**	**99,855**	**131,407**	**165,191**	**117,789**

Notes: • Totals may not equal sum of components because of independent rounding. • Petroleum includes distillate fuel oil, residual fuel oil, other fuel oils (kerosene, jet fuel, and waste oil), but excludes petroleum coke. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table 7. Average Delivered Cost of Petroleum by Census Division and State, 1997-2001

	2001		2000		1999		1998		1997	
	(cents per million Btu)	(dollars per barrel)	(cents per million Btu)	(dollars per barrel)	(cents per million Btu)	(dollars per barrel)	(cents per million Btu)	(dollars per barrel)	(cents per million Btu)	(dollars per barrel)
New England	**359.26**	**22.82**	**398.00**	**25.16**	**218.44**	**13.98**	**203.55**	**12.97**	**274.30**	**17.51**
Connecticut	—	—	—	—	223.53	14.30	218.73	13.98	292.66	18.74
Maine	—	—	—	—	177.89	11.27	202.14	12.84	278.85	17.69
Massachusetts	494.01	29.97	553.28	33.30	243.24	15.31	192.57	12.25	260.67	16.60
New Hampshire	336.71	21.56	345.31	22.30	213.63	13.75	187.21	11.94	263.55	16.89
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	675.45	38.04	—	—	327.10	18.70	453.50	26.04
Middle Atlantic	**351.55**	**22.37**	**427.76**	**27.14**	**247.38**	**15.62**	**210.60**	**13.30**	**285.35**	**18.02**
New Jersey	453.98	28.60	484.08	30.41	288.15	18.07	242.17	15.12	298.68	18.63
New York	350.24	22.29	430.64	27.34	236.53	14.96	203.46	12.88	284.12	17.94
Pennsylvania	372.94	23.42	384.64	24.39	269.09	16.96	225.74	14.19	284.69	18.09
East North Central	**482.49**	**29.31**	**515.49**	**31.10**	**334.36**	**20.36**	**288.74**	**17.70**	**382.34**	**23.20**
Illinois	578.71	35.47	705.65	40.73	345.05	21.13	275.19	17.19	375.00	23.14
Indiana	568.74	32.74	669.94	38.66	426.29	24.57	319.39	18.42	453.13	26.08
Michigan	428.09	26.45	414.88	25.76	289.22	18.11	280.60	17.45	345.07	21.40
Ohio	600.86	35.19	668.67	38.68	391.67	22.71	332.58	19.24	436.98	25.33
Wisconsin	644.49	37.90	626.74	36.85	413.67	24.32	348.95	20.52	462.61	27.13
West North Central	**388.85**	**24.94**	**508.23**	**31.42**	**359.52**	**21.59**	**292.58**	**17.46**	**346.51**	**21.46**
Iowa	617.05	36.13	643.05	37.47	398.77	23.34	332.87	19.45	445.19	25.85
Kansas	336.09	22.06	400.02	26.02	318.97	19.77	265.52	16.14	282.08	18.26
Minnesota	668.49	38.75	660.32	38.18	420.93	24.33	352.66	20.41	483.15	27.74
Missouri	605.66	35.05	648.74	37.55	381.48	22.12	274.96	16.56	364.45	22.05
Nebraska	655.63	38.02	648.52	37.52	431.50	24.95	354.48	20.49	450.28	26.02
North Dakota	638.55	37.19	692.29	40.40	417.23	24.34	311.92	18.19	459.17	26.82
South Dakota	—	—	—	—	—	—	—	—	—	—
South Atlantic	**364.67**	**23.20**	**434.76**	**27.74**	**249.70**	**15.89**	**209.19**	**13.27**	**276.08**	**17.63**
Delaware	380.46	24.37	445.87	28.18	243.85	15.46	214.67	13.61	277.95	17.68
District of Columbia	—	—	543.43	32.56	339.54	20.43	252.87	15.20	357.68	21.69
Florida	360.24	22.98	430.47	27.56	245.62	15.69	205.92	13.11	270.18	17.32
Georgia	668.41	38.88	690.61	40.17	389.64	22.66	327.62	19.06	420.79	24.83
Maryland	—	—	400.66	25.27	257.42	16.33	211.46	13.39	296.36	18.79
North Carolina	584.30	33.95	615.59	35.77	398.38	23.12	310.51	18.02	427.73	24.84
South Carolina	584.56	33.91	672.33	39.04	406.74	23.60	327.63	19.01	454.10	26.33
Virginia	356.53	22.51	423.86	26.88	229.85	14.54	203.68	12.85	281.85	17.55
West Virginia	665.73	38.82	721.34	42.21	463.49	27.08	370.91	21.68	464.01	27.07
East South Central	**383.85**	**24.86**	**356.63**	**23.10**	**181.13**	**11.84**	**205.67**	**13.51**	**289.77**	**18.82**
Alabama	552.08	32.01	651.66	37.61	325.95	19.05	287.62	16.85	405.22	23.77
Kentucky	567.25	33.20	680.76	39.90	431.89	25.31	383.28	22.43	482.93	28.28
Mississippi	377.36	24.54	333.34	21.78	154.08	10.22	199.20	13.16	269.06	17.73
Tennessee	553.80	32.54	635.17	37.32	393.30	23.11	304.46	17.89	439.03	25.80
West South Central	**591.82**	**36.24**	**557.19**	**33.72**	**255.93**	**16.07**	**250.14**	**15.80**	**361.46**	**22.37**
Arkansas	626.39	37.11	465.74	27.48	329.27	19.47	370.79	21.99	470.21	27.66
Louisiana	518.97	32.93	459.17	28.90	204.17	13.25	222.29	14.32	301.80	19.46
Oklahoma	632.95	37.35	586.06	34.68	495.50	29.62	292.18	17.42	409.22	24.08
Texas	675.37	39.86	655.75	38.47	395.99	22.95	362.09	21.12	453.65	26.38
Mountain	**771.95**	**44.94**	**798.76**	**46.37**	**487.19**	**28.33**	**423.88**	**24.69**	**532.91**	**31.14**
Arizona	810.92	47.41	859.86	50.06	479.84	27.95	428.96	25.02	531.82	31.35
Colorado	721.43	39.77	693.72	39.61	543.83	30.92	—	—	—	—
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	—	—	—	—	490.96	28.89	466.02	27.60	529.36	31.35
Nevada	585.06	34.18	721.57	42.16	452.65	26.45	379.62	22.14	507.65	29.59
New Mexico	631.49	36.07	758.49	43.32	502.33	28.69	439.32	25.09	574.63	32.82
Utah	634.50	37.24	678.63	39.70	513.62	30.14	439.55	25.80	583.60	34.27
Wyoming	707.19	41.37	724.33	42.35	476.01	27.81	405.50	23.70	517.00	30.14
Pacific Contiguous	**615.66**	**37.22**	**799.13**	**46.99**	**413.21**	**24.43**	**292.44**	**17.69**	**494.39**	**29.06**
California	600.85	37.09	619.36	36.42	327.22	19.91	274.69	16.71	—	—
Oregon	636.17	37.41	858.58	50.48	414.10	24.35	331.90	19.52	490.18	28.82
Washington	—	—	664.02	39.04	478.79	28.15	405.35	23.82	499.12	29.34
Pacific Noncontiguous	**490.34**	**30.80**	**503.91**	**31.68**	**319.88**	**20.08**	**261.47**	**16.39**	**364.26**	**22.85**
Alaska	—	—	—	—	—	—	—	—	—	—
Hawaii	490.34	30.80	503.91	31.68	319.88	20.08	261.47	16.39	364.26	22.85
Total	**392.05**	**24.86**	**445.00**	**28.24**	**252.73**	**16.03**	**213.59**	**13.55**	**287.98**	**18.30**

Notes: • Totals may not equal sum of components because of independent rounding. • Petroleum includes distillate fuel oil, residual fuel oil, other fuel oils (kerosene, jet fuel, and waste oil), but excludes petroleum coke. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table 8. Receipts and Average Delivered Cost of Petroleum by Type of Purchase, Fuel Type, Census Division and State, 2001

Census Division and State	No. 6 Fuel Oil by Type of Purchase						Average Delivered Cost					
	Contract			Spot			No. 2 Fuel Oil		No. 4, No. 5 Fuel Oil		No. 6 Fuel Oil	
	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)	(cents per Million Btu)	($ per bbl)	(cents per Million Btu)	($ per bbl)	(cents per Million Btu)	($ per bbl)
New England	—	—	—	987	336.85	21.61	578.84	33.56	—	—	336.85	21.61
Connecticut	—	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	86	420.13	26.51	580.83	33.69	—	—	420.13	26.51
New Hampshire	—	—	—	902	329.07	21.15	573.92	33.22	—	—	329.07	21.15
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	12,462	336.08	21.49	3,212	400.48	25.09	570.83	33.51	—	—	349.07	22.23
New Jersey	41	392.65	25.79	—	—	—	573.85	33.46	—	—	392.65	25.79
New York	12,421	335.89	21.48	2,672	414.60	25.90	504.54	29.85	—	—	349.56	22.26
Pennsylvania	—	—	—	540	331.85	21.10	618.92	36.18	—	—	331.85	21.10
East North Central	—	—	—	1,783	390.41	24.86	594.06	34.20	—	—	390.41	24.86
Illinois	—	—	—	111	537.20	34.18	647.55	37.42	—	—	537.20	34.18
Indiana	—	—	—	—	—	—	568.74	32.74	—	—	—	—
Michigan	—	—	—	1,672	380.67	24.24	583.51	32.87	—	—	380.67	24.24
Ohio	—	—	—	—	—	—	600.86	35.19	—	—	—	—
Wisconsin	—	—	—	—	—	—	644.49	37.90	—	—	—	—
West North Central	—	—	—	1,447	320.34	21.21	618.18	35.88	—	—	320.34	21.21
Iowa	—	—	—	—	—	—	617.05	36.13	—	—	—	—
Kansas	—	—	—	1,447	320.34	21.21	601.65	34.57	—	—	320.34	21.21
Minnesota	—	—	—	—	—	—	668.49	38.75	—	—	—	—
Missouri	—	—	—	—	—	—	605.66	35.05	—	—	—	—
Nebraska	—	—	—	—	—	—	655.63	38.02	—	—	—	—
North Dakota	—	—	—	—	—	—	638.55	37.19	—	—	—	—
South Dakota	—	—	—	—	—	—	—	—	—	—	—	—
South Atlantic	27,341	357.07	22.88	37,023	354.50	22.57	606.77	35.33	390.40	24.71	355.60	22.70
Delaware	—	—	—	470	380.14	24.36	498.90	28.92	—	—	380.14	24.36
District of Columbia	—	—	—	—	—	—	—	—	—	—	—	—
Florida	27,341	357.07	22.88	29,798	357.88	22.80	564.52	32.71	390.40	24.71	357.49	22.84
Georgia	—	—	—	—	—	—	668.41	38.88	—	—	—	—
Maryland	—	—	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	584.30	33.95	—	—	—	—
South Carolina	—	—	—	—	—	—	584.56	33.91	—	—	—	—
Virginia	—	—	—	6,754	337.72	21.44	612.25	35.98	—	—	337.72	21.44
West Virginia	—	—	—	—	—	—	665.73	38.82	—	—	—	—
East South Central	—	—	—	8,348	374.94	24.42	561.59	32.83	—	—	374.94	24.42
Alabama	—	—	—	—	—	—	552.08	32.01	—	—	—	—
Kentucky	—	—	—	—	—	—	567.25	33.20	—	—	—	—
Mississippi	—	—	—	8,348	374.94	24.42	567.92	33.21	—	—	374.94	24.42
Tennessee	—	—	—	—	—	—	553.80	32.54	—	—	—	—
West South Central	—	—	—	1,592	483.09	31.38	653.72	38.58	646.20	40.49	483.09	31.38
Arkansas	—	—	—	—	—	—	626.39	37.11	—	—	—	—
Louisiana	—	—	—	1,592	483.09	31.38	602.42	36.27	—	—	483.09	31.38
Oklahoma	—	—	—	—	—	—	632.95	37.35	—	—	—	—
Texas	—	—	—	—	—	—	679.81	39.78	646.20	40.49	—	—
Mountain	—	—	—	—	—	—	771.95	44.94	—	—	—	—
Arizona	—	—	—	—	—	—	810.92	47.41	—	—	—	—
Colorado	—	—	—	—	—	—	721.43	39.77	—	—	—	—
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	—	—	—	—	—	—	—	—	—	—	—	—
Nevada	—	—	—	—	—	—	585.06	34.18	—	—	—	—
New Mexico	—	—	—	—	—	—	631.49	36.07	—	—	—	—
Utah	—	—	—	—	—	—	634.50	37.24	—	—	—	—
Wyoming	—	—	—	—	—	—	707.19	41.37	—	—	—	—
Pacific Contiguous	—	—	—	369	594.98	37.18	635.35	37.26	—	—	594.98	37.18
California	—	—	—	369	594.98	37.18	631.66	36.61	—	—	594.98	37.18
Oregon	—	—	—	—	—	—	636.17	37.41	—	—	—	—
Washington	—	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	10,228	489.78	30.77	—	—	—	676.56	39.20	—	—	489.78	30.77
Alaska	—	—	—	—	—	—	—	—	—	—	—	—
Hawaii	10,228	489.78	30.77	—	—	—	676.56	39.20	—	—	489.78	30.77
Total	50,031	378.55	24.14	54,761	365.61	23.38	629.50	36.75	642.17	40.24	371.78	23.74

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Cost = average delivered cost.

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

Table 9. Receipts and Average Delivered Cost of Petroleum by Type, Census Division, and State, 2001

Census Division and State	No. 2 Fuel Oil			Nos. 4 & 5 Fuel Oil[1]			No. 6 Fuel Oil			Total		
	Receipts (1,000 barrels)	Heat Value (Btu per gallon)	Cost (cents per Million Btu)	Receipts (1,000 barrels)	Heat Value (Btu per gallon)	Cost (cents per Million Btu)	Receipts (1,000 barrels)	Heat Value (Btu per gallon)	Cost (cents per Million Btu)	Receipts (1,000 barrels)	Heat Value (Btu per gallon)	Cost (cents per Million Btu)
New England	**112**	**138,023**	**578.84**	—	—	—	**987**	**152,762**	**336.85**	**1,099**	**151,266**	**359.26**
Connecticut	—	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	79	138,113	580.83	—	—	—	86	150,259	420.13	165	144,420	494.01
New Hampshire	32	137,800	573.92	—	—	—	902	153,000	329.07	934	152,476	336.71
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**193**	**139,757**	**570.83**	—	—	—	**15,674**	**151,616**	**349.07**	**15,867**	**151,472**	**351.55**
New Jersey	24	138,828	573.85	—	—	—	41	156,400	392.65	64	149,974	453.98
New York	71	140,852	504.54	—	—	—	15,093	151,612	349.56	15,164	151,561	350.24
Pennsylvania	98	139,183	618.92	—	—	—	540	151,375	331.85	638	149,500	372.94
East North Central	**1,627**	**137,060**	**594.06**	—	—	—	**1,783**	**151,582**	**390.41**	**3,410**	**144,652**	**482.49**
Illinois	74	137,595	647.55	—	—	—	111	151,484	537.20	185	145,942	578.71
Indiana	311	137,068	568.74	—	—	—	—	—	—	311	137,068	568.74
Michigan	576	134,113	583.51	—	—	—	1,672	151,588	380.67	2,248	147,107	428.09
Ohio	548	139,451	600.86	—	—	—	—	—	—	548	139,451	600.86
Wisconsin	118	140,000	644.49	—	—	—	—	—	—	118	140,000	644.49
West North Central	**493**	**138,212**	**618.18**	—	—	—	**1,447**	**157,644**	**320.34**	**1,940**	**152,706**	**388.85**
Iowa	153	139,423	617.05	—	—	—	—	—	—	153	139,423	617.05
Kansas	99	136,822	601.65	—	—	—	1,447	157,644	320.34	1,546	156,312	336.09
Minnesota	41	138,002	668.49	—	—	—	—	—	—	41	138,002	668.49
Missouri	138	137,780	605.66	—	—	—	—	—	—	138	137,780	605.66
Nebraska	11	138,068	655.63	—	—	—	—	—	—	11	138,068	655.63
North Dakota	51	138,653	638.55	—	—	—	—	—	—	51	138,653	638.55
South Dakota	—	—	—	—	—	—	—	—	—	—	—	—
South Atlantic	**2,571**	**138,649**	**606.77**	**4**	**150,712**	**390.40**	**64,363**	**151,991**	**355.60**	**66,987**	**151,469**	**364.67**
Delaware	1	137,997	498.90	—	—	—	470	152,559	380.14	471	152,515	380.46
District of Columbia	—	—	—	—	—	—	—	—	—	—	—	—
Florida	759	137,979	564.52	4	150,712	390.40	57,139	152,085	357.49	57,951	151,888	360.24
Georgia	323	138,498	668.41	—	—	—	—	—	—	323	138,498	668.41
Maryland	—	—	—	—	—	—	—	—	—	—	—	—
North Carolina	439	138,339	584.30	—	—	—	—	—	—	439	138,339	584.30
South Carolina	138	138,119	584.56	—	—	—	—	—	—	138	138,119	584.56
Virginia	537	139,937	612.25	—	—	—	6,754	151,157	337.72	7,291	150,331	356.53
West Virginia	374	138,852	665.73	—	—	—	—	—	—	374	138,852	665.73
East South Central	**466**	**139,170**	**561.59**	—	—	—	**8,348**	**155,067**	**374.94**	**8,814**	**154,226**	**383.85**
Alabama	93	138,029	552.08	—	—	—	—	—	—	93	138,029	552.08
Kentucky	158	139,349	567.25	—	—	—	—	—	—	158	139,349	567.25
Mississippi	118	139,232	567.92	—	—	—	8,348	155,067	374.94	8,466	154,846	377.36
Tennessee	97	139,900	553.80	—	—	—	—	—	—	97	139,900	553.80
West South Central	**2,843**	**140,511**	**653.72**	**253**	**149,178**	**646.20**	**1,592**	**154,642**	**483.09**	**4,688**	**145,778**	**591.82**
Arkansas	85	141,070	626.39	—	—	—	—	—	—	85	141,070	626.39
Louisiana	739	143,349	602.42	—	—	—	1,592	154,642	483.09	2,331	151,064	518.97
Oklahoma	242	140,496	632.95	—	—	—	—	—	—	242	140,496	632.95
Texas	1,778	139,308	679.81	253	149,178	646.20	—	—	—	2,031	140,536	675.37
Mountain	**675**	**138,608**	**771.95**	—	—	—	—	—	—	**675**	**138,608**	**771.95**
Arizona	480	139,208	810.92	—	—	—	—	—	—	480	139,208	810.92
Colorado	43	131,246	721.43	—	—	—	—	—	—	43	131,246	721.43
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	—	—	—	—	—	—	—	—	—	—	—	—
Nevada	9	139,110	585.06	—	—	—	—	—	—	9	139,110	585.06
New Mexico	29	136,000	631.49	—	—	—	—	—	—	29	136,000	631.49
Utah	49	139,732	634.50	—	—	—	—	—	—	49	139,732	634.50
Wyoming	65	139,291	707.19	—	—	—	—	—	—	65	139,291	707.19
Pacific Contiguous	**413**	**139,632**	**635.35**	—	—	—	**369**	**148,800**	**594.98**	**782**	**143,959**	**615.66**
California	76	138,000	631.66	—	—	—	369	148,800	594.98	445	146,958	600.85
Oregon	337	140,000	636.17	—	—	—	—	—	—	337	140,000	636.17
Washington	—	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	**34**	**137,954**	**676.56**	—	—	—	**10,228**	**149,586**	**489.78**	**10,262**	**149,548**	**490.34**
Alaska	—	—	—	—	—	—	—	—	—	—	—	—
Hawaii	34	137,954	676.56	—	—	—	10,228	149,586	489.78	10,262	149,548	490.34
Total	**9,426**	**138,992**	**629.50**	**257**	**149,202**	**642.17**	**104,791**	**152,053**	**371.78**	**114,523**	**150,965**	**392.05**

[1] Blend of No. 2 Fuel Oil and No. 6 Fuel Oil.

Notes: • May include small amounts of kerosene. • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Total receipts include 49,000 barrels of 'other fuel oils' such as kerosene, jet fuel, and waste oil. • Cost = average delivered cost.

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

Table 10. Receipts and Average Delivered Cost of Residual Oil by Sulfur Content, Census Division, and State, 2001

Census Division and State	0.3% or Less			More than 0.3% up to 0.5%			More than 0.5% up to 1.0%		
	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)
New England	51	444.36	28.10	—	—	—	936	331.06	21.26
Connecticut	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—
Massachusetts	51	444.36	28.10	—	—	—	34	383.99	24.16
New Hampshire	—	—	—	—	—	—	902	329.07	21.15
Rhode Island	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—
Middle Atlantic	3,821	409.58	25.63	1,115	414.74	26.28	10,737	321.30	20.60
New Jersey	—	—	—	—	—	—	41	392.65	25.79
New York	3,821	409.58	25.63	745	433.81	27.49	10,526	322.39	20.66
Pennsylvania	—	—	—	370	376.33	23.85	170	236.05	15.12
East North Central	229	436.43	27.28	145	458.52	27.95	409	456.82	28.05
Illinois	111	537.20	34.18	—	—	—	—	—	—
Indiana	—	—	—	—	—	—	—	—	—
Michigan	118	338.75	20.83	145	458.52	27.95	409	456.82	28.05
Ohio	—	—	—	—	—	—	—	—	—
Wisconsin	—	—	—	—	—	—	—	—	—
West North Central	—	—	—	—	—	—	—	—	—
Iowa	—	—	—	—	—	—	—	—	—
Kansas	—	—	—	—	—	—	—	—	—
Minnesota	—	—	—	—	—	—	—	—	—
Missouri	—	—	—	—	—	—	—	—	—
Nebraska	—	—	—	—	—	—	—	—	—
North Dakota	—	—	—	—	—	—	—	—	—
South Dakota	—	—	—	—	—	—	—	—	—
South Atlantic	4	328.50	19.00	1,086	389.25	22.59	36,220	365.33	23.26
Delaware	—	—	—	—	—	—	470	380.14	24.36
District of Columbia	—	—	—	—	—	—	—	—	—
Florida	4	328.50	19.00	1,086	389.25	22.59	33,540	365.66	23.29
Georgia	—	—	—	—	—	—	—	—	—
Maryland	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	—	—	—
South Carolina	—	—	—	—	—	—	—	—	—
Virginia	—	—	—	—	—	—	2,210	357.02	22.55
West Virginia	—	—	—	—	—	—	—	—	—
East South Central	—	—	—	—	—	—	—	—	—
Alabama	—	—	—	—	—	—	—	—	—
Kentucky	—	—	—	—	—	—	—	—	—
Mississippi	—	—	—	—	—	—	—	—	—
Tennessee	—	—	—	—	—	—	—	—	—
West South Central	245	653.67	40.94	1,021	509.34	32.98	—	—	—
Arkansas	—	—	—	—	—	—	—	—	—
Louisiana	—	—	—	1,014	510.14	33.03	—	—	—
Oklahoma	—	—	—	—	—	—	—	—	—
Texas	245	653.67	40.94	7	396.00	25.21	—	—	—
Mountain	—	—	—	—	—	—	—	—	—
Arizona	—	—	—	—	—	—	—	—	—
Colorado	—	—	—	—	—	—	—	—	—
Idaho	—	—	—	—	—	—	—	—	—
Montana	—	—	—	—	—	—	—	—	—
Nevada	—	—	—	—	—	—	—	—	—
New Mexico	—	—	—	—	—	—	—	—	—
Utah	—	—	—	—	—	—	—	—	—
Wyoming	—	—	—	—	—	—	—	—	—
Pacific Contiguous	—	—	—	—	—	—	—	—	—
California	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	—	—	—	—	—	—
Washington	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	—	—	—	10,228	489.78	30.77	—	—	—
Alaska	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	10,228	489.78	30.77	—	—	—
Total	4,352	425.11	26.60	13,595	477.30	29.88	48,302	355.57	22.67

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Residual Oil includes No. 4, No. 5, and No. 6 fuel oils.• Cost = average delivered cost.

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

Table 10. Receipts and Average Delivered Cost of Residual Oil by Sulfur Content, Census Divison, and State, 2001 (Continued)

Census Division and State	More than 1.0% up to 2.0%			More than 2.0% up to 3.0%			More than 3.0%			Average Cost	
	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)	Receipts (1,000 barrels)	Cost (cents per Million Btu)	Cost ($ per bbl)	(cents per Million Btu)	($ per bbl)
New England	—	—	—	—	—	—	—	—	—	336.85	21.61
Connecticut	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	420.13	26.51
New Hampshire	—	—	—	—	—	—	—	—	—	329.07	21.15
Rhode Island	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	—	—	—	—	—	—	—	—	—	349.07	22.23
New Jersey	—	—	—	—	—	—	—	—	—	392.65	25.79
New York	—	—	—	—	—	—	—	—	—	349.56	22.26
Pennsylvania	—	—	—	—	—	—	—	—	—	331.85	21.10
East North Central	999	345.46	22.54	—	—	—	—	—	—	390.41	24.86
Illinois	—	—	—	—	—	—	—	—	—	537.20	34.18
Indiana	—	—	—	—	—	—	—	—	—	—	—
Michigan	999	345.46	22.54	—	—	—	—	—	—	380.67	24.24
Ohio	—	—	—	—	—	—	—	—	—	—	—
Wisconsin	—	—	—	—	—	—	—	—	—	—	—
West North Central	1,447	320.34	21.21	—	—	—	—	—	—	320.34	21.21
Iowa	—	—	—	—	—	—	—	—	—	—	—
Kansas	1,447	320.34	21.21	—	—	—	—	—	—	320.34	21.21
Minnesota	—	—	—	—	—	—	—	—	—	—	—
Missouri	—	—	—	—	—	—	—	—	—	—	—
Nebraska	—	—	—	—	—	—	—	—	—	—	—
North Dakota	—	—	—	—	—	—	—	—	—	—	—
South Dakota	—	—	—	—	—	—	—	—	—	—	—
South Atlantic	22,951	344.23	22.12	4,106	326.18	21.03	—	—	—	355.60	22.70
Delaware	—	—	—	—	—	—	—	—	—	380.14	24.36
District of Columbia	—	—	—	—	—	—	—	—	—	—	—
Florida	18,406	348.09	22.42	4,106	326.18	21.03	—	—	—	357.50	22.84
Georgia	—	—	—	—	—	—	—	—	—	—	—
Maryland	—	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	—	—	—	—	—
South Carolina	—	—	—	—	—	—	—	—	—	—	—
Virginia	4,544	328.40	20.90	—	—	—	—	—	—	337.72	21.44
West Virginia	—	—	—	—	—	—	—	—	—	—	—
East South Central	—	—	—	8,348	374.94	24.42	—	—	—	374.94	24.42
Alabama	—	—	—	—	—	—	—	—	—	—	—
Kentucky	—	—	—	—	—	—	—	—	—	—	—
Mississippi	—	—	—	8,348	374.94	24.42	—	—	—	374.94	24.42
Tennessee	—	—	—	—	—	—	—	—	—	—	—
West South Central	579	436.12	28.48	—	—	—	—	—	—	504.74	32.62
Arkansas	—	—	—	—	—	—	—	—	—	—	—
Louisiana	579	436.12	28.48	—	—	—	—	—	—	483.09	31.38
Oklahoma	—	—	—	—	—	—	—	—	—	—	—
Texas	—	—	—	—	—	—	—	—	—	646.20	40.49
Mountain	—	—	—	—	—	—	—	—	—	—	—
Arizona	—	—	—	—	—	—	—	—	—	—	—
Colorado	—	—	—	—	—	—	—	—	—	—	—
Idaho	—	—	—	—	—	—	—	—	—	—	—
Montana	—	—	—	—	—	—	—	—	—	—	—
Nevada	—	—	—	—	—	—	—	—	—	—	—
New Mexico	—	—	—	—	—	—	—	—	—	—	—
Utah	—	—	—	—	—	—	—	—	—	—	—
Wyoming	—	—	—	—	—	—	—	—	—	—	—
Pacific Contiguous	369	594.98	37.18	—	—	—	—	—	—	594.98	37.18
California	369	594.98	37.18	—	—	—	—	—	—	594.98	37.18
Oregon	—	—	—	—	—	—	—	—	—	—	—
Washington	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	—	—	—	—	—	—	—	—	—	489.78	30.77
Alaska	—	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	489.78	30.77
Total	26,344	348.38	22.44	12,454	358.97	23.30	—	—	—	372.43	23.78

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Residual Oil includes No. 4, No. 5, and No. 6 fuel oils.• Cost = average delivered cost.

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

Table 11. Receipts of Gas by Census Division and State, 1997-2001
(Thousand Mcf)

	2001	2000	1999	1998	1997
New England	**5,458**	**7,422**	**23,065**	**47,377**	**95,374**
Connecticut	—	—	14,093	10,396	13,738
Maine	—	—	—	—	—
Massachusetts	4,865	5,998	8,524	21,207	50,755
New Hampshire	495	351	196	—	302
Rhode Island	—	—	—	15,586	30,544
Vermont	99	1,073	252	187	34
Middle Atlantic	**92,646**	**101,385**	**209,381**	**226,248**	**236,208**
New Jersey	785	8,674	19,473	16,742	17,920
New York	91,741	90,372	180,131	204,700	215,276
Pennsylvania	120	2,339	9,778	4,807	3,012
East North Central	**34,425**	**43,561**	**89,494**	**102,818**	**79,833**
Illinois	4,021	1,127	34,497	51,887	44,986
Indiana	1,447	2,427	3,816	4,258	2,631
Michigan	25,355	34,982	43,686	40,813	28,208
Ohio	433	1,412	3,222	1,532	719
Wisconsin	3,168	3,612	4,273	4,328	3,289
West North Central	**28,238**	**40,300**	**45,268**	**43,200**	**29,509**
Iowa	2,910	3,852	3,958	3,154	2,748
Kansas	17,721	27,561	29,991	29,899	20,050
Minnesota	1,436	2,167	2,246	2,176	2,768
Missouri	5,208	5,298	7,402	5,984	2,889
Nebraska	962	1,421	1,671	1,981	1,053
North Dakota	1	1	*	1	1
South Dakota	—	—	—	5	—
South Atlantic	**270,233**	**289,386**	**335,459**	**285,398**	**310,596**
Delaware	220	4,563	21,859	11,148	15,997
District of Columbia	—	—	—	—	—
Florida	258,805	254,847	269,232	241,059	276,254
Georgia	1,241	4,251	10,684	10,682	3,074
Maryland	—	11,770	12,149	4,988	4,864
North Carolina	746	1,597	1,986	1,879	1,220
South Carolina	798	113	337	435	196
Virginia	8,245	12,012	18,807	14,859	8,619
West Virginia	179	234	405	348	372
East South Central	**85,356**	**71,741**	**76,294**	**56,595**	**49,081**
Alabama	12,952	6,795	2,174	1,731	1,194
Kentucky	353	656	875	805	576
Mississippi	72,051	64,290	73,245	54,059	47,311
Tennessee	—	—	—	—	—
West South Central	**1,288,995**	**1,682,834**	**1,676,039**	**1,712,041**	**1,445,739**
Arkansas	20,408	26,947	26,189	22,561	17,490
Louisiana	224,186	292,002	306,767	289,492	264,879
Oklahoma	146,409	162,751	160,569	177,976	133,617
Texas	897,992	1,201,134	1,182,513	1,222,012	1,029,752
Mountain	**200,531**	**215,506**	**162,672**	**134,733**	**111,722**
Arizona	65,221	71,966	48,136	35,888	22,010
Colorado	40,041	28,818	15,799	3,544	2,361
Idaho	—	—	—	—	—
Montana	11	16	373	199	103
Nevada	46,935	67,341	58,902	51,812	52,189
New Mexico	36,836	37,905	34,862	39,169	32,753
Utah	11,083	8,864	4,435	4,045	2,207
Wyoming	405	596	166	77	98
Pacific Contiguous	**128,834**	**161,060**	**171,352**	**295,660**	**385,685**
California	85,688	121,362	148,001	266,743	374,700
Oregon	43,147	39,698	23,351	28,915	10,969
Washington	—	—	—	2	15
Pacific Noncontiguous	**17,649**	**16,792**	**20,430**	**18,887**	**20,989**
Alaska	17,649	16,792	20,430	18,887	20,989
Hawaii	—	—	—	—	—
Total	**2,152,366**	**2,629,986**	**2,809,455**	**2,922,957**	**2,764,734**

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

Notes: • Totals may not equal sum of components because of independent rounding. • Gas includes natural gas and other gas, which includes blast furnace, coke oven, and refinery gas. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table 12. Average Delivered Cost of Gas by Census Division and State, 1997-2001

	2001		2000		1999		1998		1997	
	(cents per million Btu)	(dollars per Mcf)	(cents per million Btu)	(dollars per Mcf)	(cents per million Btu)	(dollars per Mcf)	(cents per million Btu)	(dollars per Mcf)	(cents per million Btu)	(dollars per Mcf)
New England	**339.54**	**3.51**	**443.36**	**4.59**	**267.09**	**2.74**	**283.75**	**2.92**	**300.60**	**3.09**
Connecticut	—	—	—	—	267.33	2.74	236.90	2.44	242.11	2.47
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	347.48	3.58	443.75	4.60	265.31	2.72	273.81	2.82	300.98	3.11
New Hampshire	238.70	2.56	315.09	3.37	261.02	2.67	—	—	266.58	2.71
Rhode Island	—	—	—	—	—	—	328.55	3.38	326.39	3.35
Vermont	477.64	4.83	485.50	4.91	319.27	3.23	286.06	2.90	312.12	3.16
Middle Atlantic	**404.68**	**4.12**	**455.05**	**4.64**	**281.14**	**2.88**	**251.96**	**2.60**	**282.19**	**2.90**
New Jersey	335.64	3.43	430.37	4.42	298.93	3.08	262.02	2.74	295.14	3.06
New York	404.68	4.12	459.65	4.68	278.55	2.85	249.61	2.57	280.96	2.88
Pennsylvania	851.43	8.87	370.68	3.83	293.14	3.03	316.51	3.26	292.52	3.02
East North Central	**397.33**	**3.72**	**406.81**	**3.13**	**251.20**	**2.06**	**230.63**	**1.91**	**259.70**	**1.99**
Illinois	368.47	3.79	469.12	4.84	236.18	2.41	220.68	2.25	251.36	2.55
Indiana	507.04	5.18	445.34	4.56	289.27	2.97	280.46	2.88	316.26	3.23
Michigan	377.31	3.42	389.92	2.77	252.26	1.53	232.41	1.26	256.33	.80
Ohio	797.22	8.17	485.47	4.98	306.36	3.15	308.38	3.17	362.93	3.72
Wisconsin	472.60	4.76	444.48	4.48	290.54	2.93	264.06	2.68	314.74	3.17
West North Central	**400.91**	**4.03**	**424.74**	**4.28**	**249.48**	**2.51**	**224.14**	**2.25**	**267.81**	**2.64**
Iowa	477.11	4.78	454.74	4.56	313.74	3.15	305.90	3.07	339.80	3.41
Kansas	357.83	3.60	414.16	4.18	234.11	2.36	213.73	2.14	258.36	2.53
Minnesota	520.83	5.25	448.65	4.54	266.29	2.69	233.78	2.36	243.64	2.45
Missouri	467.02	4.69	438.96	4.42	265.55	2.66	223.40	2.26	279.41	2.81
Nebraska	427.58	4.29	459.99	4.61	281.13	2.80	242.75	2.40	287.11	2.86
North Dakota	687.47	7.08	639.94	6.69	404.04	4.21	369.27	3.88	321.99	3.43
South Dakota	—	—	—	—	—	—	176.70	1.77	—	—
South Atlantic	**451.61**	**4.71**	**435.51**	**4.52**	**296.56**	**3.08**	**279.34**	**2.93**	**302.90**	**3.16**
Delaware	427.23	4.41	488.49	4.92	303.25	2.98	297.73	2.89	304.70	3.15
District of Columbia	—	—	—	—	—	—	—	—	—	—
Florida	453.16	4.73	433.75	4.50	297.23	3.10	276.17	2.91	304.29	3.18
Georgia	327.76	3.36	417.64	4.31	248.90	2.57	316.01	3.25	265.46	2.72
Maryland	—	—	442.30	4.62	307.59	3.20	263.19	2.75	285.28	2.97
North Carolina	435.01	4.50	432.15	4.43	283.31	2.92	267.87	2.81	310.66	3.22
South Carolina	256.70	2.64	556.87	5.72	347.33	3.57	353.41	3.62	397.58	4.07
Virginia	438.10	4.53	451.15	4.66	299.65	3.17	295.43	3.10	274.04	2.93
West Virginia	646.48	6.46	498.08	4.98	299.80	3.00	351.43	3.51	335.15	3.35
East South Central	**369.52**	**3.80**	**395.60**	**4.07**	**245.22**	**2.52**	**224.46**	**2.33**	**263.42**	**2.73**
Alabama	505.48	5.20	437.49	4.52	295.09	2.98	247.52	2.59	277.17	2.86
Kentucky	458.91	4.70	495.83	5.08	340.40	3.49	331.89	3.40	337.34	3.45
Mississippi	344.60	3.54	390.13	4.01	242.63	2.49	222.14	2.31	262.18	2.72
Tennessee	—	—	—	—	—	—	—	—	—	—
West South Central	**422.76**	**4.35**	**422.64**	**4.33**	**248.99**	**2.55**	**227.02**	**2.33**	**266.67**	**2.74**
Arkansas	429.03	4.44	437.52	4.46	253.04	2.59	224.02	2.29	261.91	2.70
Louisiana	413.19	4.30	439.62	4.55	249.03	2.59	227.36	2.37	269.28	2.79
Oklahoma	448.22	4.62	441.62	4.54	271.67	2.79	241.16	2.48	287.81	2.97
Texas	420.86	4.32	415.53	4.24	245.79	2.51	224.92	2.30	263.30	2.69
Mountain	**515.57**	**5.27**	**446.91**	**4.56**	**247.49**	**2.53**	**230.81**	**2.36**	**245.50**	**2.51**
Arizona	460.36	4.70	477.89	4.86	264.32	2.67	239.09	2.42	294.44	2.99
Colorado	375.43	3.81	403.09	4.12	256.92	2.65	300.30	2.98	317.48	3.16
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	666.39	7.54	510.39	5.81	184.50	2.02	191.77	2.06	1348.51	14.45
Nevada	802.55	8.22	474.97	4.86	242.28	2.51	230.18	2.38	211.87	2.18
New Mexico	415.00	4.22	387.73	3.94	228.25	2.31	219.95	2.22	259.16	2.64
Utah	463.59	4.88	383.62	4.02	253.83	2.65	202.49	2.11	202.95	2.09
Wyoming	381.76	4.01	375.77	3.92	372.26	3.89	796.04	8.31	875.94	9.12
Pacific Contiguous	**741.67**	**7.52**	**509.07**	**5.16**	**261.77**	**2.65**	**257.51**	**2.63**	**298.00**	**3.04**
California	928.12	9.38	581.15	5.88	272.53	2.76	268.62	2.74	302.20	3.08
Oregon	374.91	3.82	289.58	2.94	193.61	1.96	154.07	1.56	147.57	1.49
Washington	—	—	—	—	—	—	325.87	3.44	4519.49	47.38
Pacific Noncontiguous	**236.09**	**2.36**	**177.06**	**1.77**	**159.28**	**1.59**	**179.77**	**1.80**	**173.98**	**1.74**
Alaska	236.09	2.36	177.06	1.77	159.28	1.59	179.77	1.80	173.98	1.74
Hawaii	—	—	—	—	—	—	—	—	—	—
Total	**448.65**	**4.61**	**430.19**	**4.39**	**257.36**	**2.62**	**238.10**	**2.43**	**275.98**	**2.81**

Notes: • Totals may not equal sum of components because of independent rounding. • Gas includes natural gas and other gas, which includes blast furnace, coke oven, and refinery gas. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.

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

Table 13. Receipts and Average Delivered Cost of Gas by Type of Purchase, Census Division and State, 2001

Census Division and State	Type of Purchase											
	Firm			Interruptible			Spot			Total		
	Receipts (1,000 Mcf)	Cost (cents per Million Btu)	Cost ($ per Mcf)	Receipts (1,000 Mcf)	Cost (cents per Million Btu)	Cost ($ per Mcf)	Receipts (1,000 Mcf)	Cost (cents per Million Btu)	Cost ($ per Mcf)	Receipts (1,000 Mcf)	Cost (cents per Million Btu)	Cost ($ per Mcf)
New England	—	—	—	**3,759**	**324.00**	**3.34**	**1,700**	**373.70**	**3.88**	**5,458**	**339.54**	**3.51**
Connecticut	—	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	3,467	331.68	3.41	1,398	386.37	4.00	4,865	347.48	3.58
New Hampshire	—	—	—	292	237.00	2.55	203	241.16	2.58	495	238.70	2.56
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	99	477.64	4.83	99	477.64	4.83
Middle Atlantic	**8,044**	**661.48**	**6.68**	**22,456**	**384.28**	**3.94**	**62,146**	**379.11**	**3.85**	**92,646**	**404.68**	**4.12**
New Jersey	—	—	—	785	335.64	3.43	—	—	—	785	335.64	3.43
New York	7,924	658.51	6.65	21,671	386.03	3.96	62,146	379.11	3.85	91,741	404.68	4.12
Pennsylvania	120	851.43	8.87	—	—	—	—	—	—	120	851.43	8.87
East North Central	**6,337**	**396.44**	**4.01**	**24,541**	**383.95**	**3.48**	**3,547**	**480.78**	**4.92**	**34,425**	**397.33**	**3.72**
Illinois	—	—	—	4,021	368.47	3.79	—	—	—	4,021	368.47	3.79
Indiana	—	—	—	1,447	507.04	5.18	—	—	—	1,447	507.04	5.18
Michigan	6,222	392.67	3.97	16,159	357.05	3.02	2,974	436.42	4.47	25,355	377.31	3.42
Ohio	115	597.62	6.15	17	868.07	8.68	301	869.64	8.91	433	797.22	8.17
Wisconsin	—	—	—	2,897	466.67	4.70	272	536.37	5.36	3,168	472.60	4.76
West North Central	**2,541**	**408.56**	**4.01**	**20,885**	**393.11**	**3.96**	**4,811**	**431.02**	**4.32**	**28,238**	**400.91**	**4.03**
Iowa	122	631.71	6.40	643	520.44	5.25	2,146	455.16	4.56	2,910	477.11	4.78
Kansas	1,757	377.78	3.67	14,963	349.96	3.53	1,000	441.82	4.46	17,721	357.83	3.60
Minnesota	69	876.58	8.86	916	520.77	5.27	452	466.40	4.67	1,436	520.83	5.25
Missouri	98	362.39	3.70	3,897	501.01	5.03	1,214	366.39	3.68	5,208	467.02	4.69
Nebraska	496	402.88	4.03	466	453.66	4.56	—	—	—	962	427.58	4.29
North Dakota	—	—	—	1	687.47	7.08	—	—	—	1	687.47	7.08
South Dakota	—	—	—	—	—	—	—	—	—	—	—	—
South Atlantic	**234,112**	**457.91**	**4.78**	**26,305**	**405.19**	**4.22**	**9,816**	**425.57**	**4.41**	**270,233**	**451.61**	**4.71**
Delaware	220	427.23	4.41	—	—	—	—	—	—	220	427.23	4.41
District of Columbia	—	—	—	—	—	—	—	—	—	—	—	—
Florida	233,888	457.94	4.78	23,346	411.53	4.30	1,571	360.21	3.75	258,805	453.16	4.73
Georgia	—	—	—	1,241	327.76	3.36	—	—	—	1,241	327.76	3.36
Maryland	—	—	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	746	435.01	4.50	—	—	—	746	435.01	4.50
South Carolina	—	—	—	798	256.70	2.64	—	—	—	798	256.70	2.64
Virginia	—	—	—	—	—	—	8,245	438.10	4.53	8,245	438.10	4.53
West Virginia	5	548.10	5.48	175	649.02	6.49	—	—	—	179	646.48	6.46
East South Central	**3,551**	**466.44**	**4.81**	**12,226**	**521.88**	**5.37**	**69,579**	**337.73**	**3.47**	**85,356**	**369.52**	**3.80**
Alabama	142	229.80	2.36	12,186	522.91	5.38	624	227.90	2.35	12,952	505.48	5.20
Kentucky	—	—	—	—	—	—	353	458.91	4.70	353	458.91	4.70
Mississippi	3,408	476.28	4.92	40	211.40	2.19	68,602	338.11	3.47	72,051	344.60	3.54
Tennessee	—	—	—	—	—	—	—	—	—	—	—	—
West South Central	**507,253**	**426.43**	**4.38**	**80,395**	**445.79**	**4.57**	**701,347**	**417.48**	**4.30**	**1,288,995**	**422.76**	**4.35**
Arkansas	—	—	—	—	—	—	20,408	429.03	4.44	20,408	429.03	4.44
Louisiana	3,048	398.13	4.17	28,094	448.69	4.70	193,044	408.23	4.24	224,186	413.19	4.30
Oklahoma	71,012	472.63	4.90	115	417.51	4.17	75,281	424.99	4.36	146,409	448.22	4.62
Texas	433,193	418.98	4.30	52,186	444.25	4.50	412,613	419.92	4.31	897,992	420.86	4.32
Mountain	**60,031**	**387.85**	**3.95**	**76,376**	**460.98**	**4.69**	**64,124**	**698.39**	**7.18**	**200,531**	**515.57**	**5.27**
Arizona	15,203	476.43	4.89	32,285	422.88	4.30	17,733	514.42	5.26	65,221	460.36	4.70
Colorado	35,851	366.95	3.73	4,190	449.94	4.46	—	—	—	40,041	375.43	3.81
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	—	—	—	11	666.39	7.54	—	—	—	11	666.39	7.54
Nevada	—	—	—	12,100	595.84	6.11	34,836	874.49	8.95	46,935	802.55	8.22
New Mexico	8,572	316.92	3.21	27,791	447.56	4.55	473	275.96	2.84	36,836	415.00	4.22
Utah	—	—	—	—	—	—	11,083	463.59	4.88	11,083	463.59	4.88
Wyoming	405	381.76	4.01	—	—	—	—	—	—	405	381.76	4.01
Pacific Contiguous	**21,130**	**699.16**	**7.01**	**5,886**	**747.86**	**7.27**	**101,819**	**750.01**	**7.64**	**128,834**	**741.67**	**7.52**
California	21,130	699.16	7.01	5,886	747.86	7.27	58,672	1026.67	10.44	85,688	928.12	9.38
Oregon	—	—	—	—	—	—	43,147	374.91	3.82	43,147	374.91	3.82
Washington	—	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	**17,266**	**234.77**	**2.35**	**383**	**295.70**	**2.96**	—	—	—	**17,649**	**236.09**	**2.36**
Alaska	17,266	234.77	2.35	383	295.70	2.96	—	—	—	17,649	236.09	2.36
Hawaii	—	—	—	—	—	—	—	—	—	—	—	—
Total	**860,265**	**437.28**	**4.50**	**273,212**	**439.72**	**4.45**	**1,018,889**	**460.61**	**4.74**	**2,152,366**	**448.65**	**4.61**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Gas includes natural gas and other gas, which includes blast furnace, coke oven, and refinery gas. • Mcf = thousand cubic feet.• Cost = average delivered cost.

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

Table 14. Receipts and Average Delivered Cost of Gas by Type, Census Division, and State, 2001

Census Division and State	Receipts by Type											
	Natural Gas			Blast Furnace/ Coke Oven Gas			Refinery Gas			Total Gas		
	Receipts (1,000 Mcf)	Heat Value (Btu per cf)	Cost (cents per Million Btu)	Receipts (1,000 Mcf)	Heat Value (Btu per cf)	Cost (cents per Million Btu)	Receipts (1,000 Mcf)	Heat Value (Btu per cf)	Cost (cents per Million Btu)	Receipts (1,000 Mcf)	Heat Value (Btu per cf)	Cost (cents per Million Btu)
New England	**5,458**	**1,034**	**339.54**	—	—	—	—	—	—	**5,458**	**1,034**	**339.54**
Connecticut	—	—	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—	—	—
Massachusetts	4,865	1,031	347.48	—	—	—	—	—	—	4,865	1,031	347.48
New Hampshire	495	1,074	238.70	—	—	—	—	—	—	495	1,074	238.70
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	99	1,012	477.64	—	—	—	—	—	—	99	1,012	477.64
Middle Atlantic	**92,646**	**1,018**	**404.68**	—	—	—	—	—	—	**92,646**	**1,018**	**404.68**
New Jersey	785	1,022	335.64	—	—	—	—	—	—	785	1,022	335.64
New York	91,741	1,018	404.68	—	—	—	—	—	—	91,741	1,018	404.68
Pennsylvania	120	1,042	851.43	—	—	—	—	—	—	120	1,042	851.43
East North Central	**31,325**	**1,016**	**401.29**	**3,100**	**140**	**106.49**	—	—	—	**34,425**	**937**	**397.33**
Illinois	4,021	1,029	368.47	—	—	—	—	—	—	4,021	1,029	368.47
Indiana	1,447	1,022	507.04	—	—	—	—	—	—	1,447	1,022	507.04
Michigan	22,255	1,014	382.51	3,100	140	106.49	—	—	—	25,355	908	377.31
Ohio	433	1,025	797.22	—	—	—	—	—	—	433	1,025	797.22
Wisconsin	3,168	1,007	472.60	—	—	—	—	—	—	3,168	1,007	472.60
West North Central	**28,238**	**1,005**	**400.91**	—	—	—	—	—	—	**28,238**	**1,005**	**400.91**
Iowa	2,910	1,003	477.11	—	—	—	—	—	—	2,910	1,003	477.11
Kansas	17,721	1,006	357.83	—	—	—	—	—	—	17,721	1,006	357.83
Minnesota	1,436	1,008	520.83	—	—	—	—	—	—	1,436	1,008	520.83
Missouri	5,208	1,005	467.02	—	—	—	—	—	—	5,208	1,005	467.02
Nebraska	962	1,003	427.58	—	—	—	—	—	—	962	1,003	427.58
North Dakota	1	1,029	687.47	—	—	—	—	—	—	1	1,029	687.47
South Dakota	—	—	—	—	—	—	—	—	—	—	—	—
South Atlantic	**270,186**	**1,043**	**451.67**	—	—	—	**47**	**1,024**	**137.91**	**270,233**	**1,043**	**451.61**
Delaware	220	1,032	427.23	—	—	—	—	—	—	220	1,032	427.23
District of Columbia	—	—	—	—	—	—	—	—	—	—	—	—
Florida	258,805	1,044	453.16	—	—	—	—	—	—	258,805	1,044	453.16
Georgia	1,241	1,025	327.76	—	—	—	—	—	—	1,241	1,025	327.76
Maryland	—	—	—	—	—	—	—	—	—	—	—	—
North Carolina	746	1,035	435.01	—	—	—	—	—	—	746	1,035	435.01
South Carolina	798	1,028	256.70	—	—	—	—	—	—	798	1,028	256.70
Virginia	8,198	1,035	439.80	—	—	—	47	1,024	137.91	8,245	1,035	438.10
West Virginia	179	1,000	646.48	—	—	—	—	—	—	179	1,000	646.48
East South Central	**85,356**	**1,028**	**369.52**	—	—	—	—	—	—	**85,356**	**1,028**	**369.52**
Alabama	12,952	1,029	505.48	—	—	—	—	—	—	12,952	1,029	505.48
Kentucky	353	1,025	458.91	—	—	—	—	—	—	353	1,025	458.91
Mississippi	72,051	1,027	344.60	—	—	—	—	—	—	72,051	1,027	344.60
Tennessee	—	—	—	—	—	—	—	—	—	—	—	—
West South Central	**1,288,995**	**1,029**	**422.76**	—	—	—	—	—	—	**1,288,995**	**1,029**	**422.76**
Arkansas	20,408	1,035	429.03	—	—	—	—	—	—	20,408	1,035	429.03
Louisiana	224,186	1,040	413.19	—	—	—	—	—	—	224,186	1,040	413.19
Oklahoma	146,409	1,031	448.22	—	—	—	—	—	—	146,409	1,031	448.22
Texas	897,992	1,026	420.86	—	—	—	—	—	—	897,992	1,026	420.86
Mountain	**200,531**	**1,021**	**515.57**	—	—	—	—	—	—	**200,531**	**1,021**	**515.57**
Arizona	65,221	1,020	460.36	—	—	—	—	—	—	65,221	1,020	460.36
Colorado	40,041	1,015	375.43	—	—	—	—	—	—	40,041	1,015	375.43
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	11	1,132	666.39	—	—	—	—	—	—	11	1,132	666.39
Nevada	46,935	1,024	802.55	—	—	—	—	—	—	46,935	1,024	802.55
New Mexico	36,836	1,017	415.00	—	—	—	—	—	—	36,836	1,017	415.00
Utah	11,083	1,053	463.59	—	—	—	—	—	—	11,083	1,053	463.59
Wyoming	405	1,049	381.76	—	—	—	—	—	—	405	1,049	381.76
Pacific Contiguous	**128,540**	**1,015**	**741.89**	**295**	**292**	**413.00**	—	—	—	**128,834**	**1,014**	**741.67**
California	85,393	1,013	928.63	295	292	413.00	—	—	—	85,688	1,010	928.12
Oregon	43,147	1,020	374.91	—	—	—	—	—	—	43,147	1,020	374.91
Washington	—	—	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	**17,649**	**1,000**	**236.09**	—	—	—	—	—	—	**17,649**	**1,000**	**236.09**
Alaska	17,649	1,000	236.09	—	—	—	—	—	—	17,649	1,000	236.09
Hawaii	—	—	—	—	—	—	—	—	—	—	—	—
Total	**2,148,924**	**1,028**	**448.72**	**3,395**	**153**	**157.22**	**47**	**1,024**	**137.91**	**2,152,366**	**1,027**	**448.65**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Mcf = thousand cubic feet. • cf = cubic foot. • Cost = average delivered cost.

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

Table 15. Total Heating Value and Cost of Fossil Fuels by Census Division and State, 2001

Census Division and State	Total Btu (billions)				% of Total Btu			Avg. Delivered Cost (cents per million Btu)		
	Total	Coal	Petroleum	Gas	Coal	Petroleum	Gas	Coal	Petroleum	Gas
New England	**57,132**	**44,505**	**6,982**	**5,645**	**77.9**	**12.2**	**9.9**	**167.22**	**359.26**	**339.54**
Connecticut	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	6,014	—	1,001	5,013	—	16.6	83.4	—	494.01	347.48
New Hampshire	51,018	44,505	5,981	532	87.2	11.7	1.0	167.22	336.71	238.70
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	100	—	—	100	—	—	100.0	—	—	477.64
Middle Atlantic	**240,343**	**45,068**	**100,941**	**94,334**	**18.8**	**42.0**	**39.2**	**143.07**	**351.55**	**404.68**
New Jersey	6,712	5,505	405	802	82.0	6.0	11.9	227.37	453.98	335.64
New York	210,152	20,216	96,529	93,407	9.6	45.9	44.4	141.60	350.24	404.68
Pennsylvania	23,478	19,347	4,007	125	82.4	17.1	.5	120.63	372.94	851.43
East North Central	**3,517,247**	**3,464,268**	**20,715**	**32,264**	**98.5**	**.6**	**.9**	**120.45**	**482.49**	**397.33**
Illinois	319,610	314,339	1,132	4,139	98.4	.4	1.3	119.16	578.71	368.47
Indiana	1,093,740	1,090,471	1,790	1,479	99.7	.2	.1	113.66	568.74	507.04
Michigan	720,949	684,048	13,890	23,011	94.9	1.9	3.2	127.48	428.09	377.31
Ohio	943,908	940,254	3,210	444	99.6	.3	*	130.96	600.86	797.22
Wisconsin	439,041	435,157	692	3,191	99.1	.2	.7	104.64	644.49	472.60
West North Central	**2,386,541**	**2,345,715**	**12,441**	**28,384**	**98.3**	**.5**	**1.2**	**89.14**	**388.85**	**400.91**
Iowa	384,266	380,453	894	2,918	99.0	.2	.8	81.36	617.05	477.11
Kansas	397,730	369,762	10,148	17,820	93.0	2.6	4.5	104.76	336.09	357.83
Minnesota	323,456	321,769	239	1,447	99.5	.1	.4	101.78	668.49	520.83
Missouri	702,324	696,291	801	5,233	99.1	.1	.7	95.76	605.66	467.02
Nebraska	223,391	222,365	62	965	99.5	*	.4	56.57	655.63	427.58
North Dakota	318,598	318,299	298	1	99.9	.1	*	74.15	638.55	687.47
South Dakota	36,776	36,776	—	—	100.0	—	—	103.27	—	—
South Atlantic[1]	**4,029,486**	**3,321,414**	**426,151**	**281,921**	**82.4**	**10.6**	**7.0**	**157.08**	**364.67**	**451.61**
Delaware	3,848	602	3,019	227	15.7	78.5	5.9	216.91	380.46	427.23
District of Columbia	—	—	—	—	—	—	—	—	—	—
Florida[1]	1,276,044	636,238	369,686	270,120	49.9	29.0	21.2	171.81	360.24	453.16
Georgia	810,936	807,784	1,881	1,272	99.6	.2	.2	166.07	668.41	327.76
Maryland	—	—	—	—	—	—	—	—	—	—
North Carolina	641,688	638,366	2,549	773	99.5	.4	.1	159.30	584.30	435.01
South Carolina	389,398	387,776	802	820	99.6	.2	.2	156.52	584.56	256.70
Virginia	328,295	273,728	46,036	8,530	83.4	14.0	2.6	159.32	356.53	438.10
West Virginia	579,278	576,920	2,179	179	99.6	.4	*	125.02	665.73	646.48
East South Central[1]	**2,274,631**	**2,129,828**	**57,092**	**87,712**	**93.6**	**2.5**	**3.9**	**126.35**	**383.85**	**369.52**
Alabama[1]	661,943	648,076	541	13,327	97.9	.1	2.0	141.07	552.08	505.48
Kentucky[1]	776,958	775,672	924	362	99.8	.1	*	110.36	567.25	458.91
Mississippi	272,581	143,502	55,057	74,023	52.6	20.2	27.2	163.46	377.36	344.60
Tennessee[1]	563,149	562,578	571	—	99.9	.1	—	121.98	553.80	—
West South Central	**3,345,325**	**1,990,281**	**28,703**	**1,326,340**	**59.5**	**.9**	**39.6**	**120.86**	**591.82**	**422.76**
Arkansas	275,582	253,964	501	21,117	92.2	.2	7.7	87.46	626.39	429.03
Louisiana	375,940	127,946	14,789	233,206	34.0	3.9	62.0	130.89	518.97	413.19
Oklahoma	449,991	297,667	1,426	150,898	66.1	.3	33.5	90.57	632.95	448.22
Texas	2,243,811	1,310,705	11,986	921,120	58.4	.5	41.1	133.24	675.37	420.86
Mountain	**2,108,307**	**1,899,551**	**3,927**	**204,829**	**90.1**	**.2**	**9.7**	**108.34**	**771.95**	**515.57**
Arizona	462,064	392,705	2,804	66,554	85.0	.6	14.4	124.97	810.92	460.36
Colorado	404,102	363,230	237	40,635	89.9	.1	10.1	92.19	721.43	375.43
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	4,022	4,010	—	12	99.7	—	.3	94.93	—	666.39
Nevada	229,066	180,934	55	48,077	79.0	*	21.0	126.19	585.06	802.55
New Mexico	252,505	214,881	166	37,459	85.1	.1	14.8	147.38	631.49	415.00
Utah	328,876	316,924	285	11,667	96.4	.1	3.5	112.30	634.50	463.59
Wyoming	427,673	426,868	381	425	99.8	.1	.1	76.74	707.19	381.76
Pacific Contiguous	**180,282**	**44,975**	**4,728**	**130,579**	**24.9**	**2.6**	**72.4**	**110.99**	**615.66**	**741.67**
California	89,316	—	2,746	86,570	—	3.1	96.9	—	600.85	928.12
Oregon	90,966	44,975	1,982	44,009	49.4	2.2	48.4	110.99	636.17	374.91
Washington	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	**82,105**	**—**	**64,456**	**17,649**	**—**	**78.5**	**21.5**	**—**	**490.34**	**236.09**
Alaska	17,649	—	—	17,649	—	—	100.0	—	—	236.09
Hawaii	64,456	—	64,456	—	—	100.0	—	—	490.34	—
Total	**18,221,398**	**15,285,607**	**726,135**	**2,209,656**	**83.9**	**4.0**	**12.1**	**123.15**	**392.05**	**448.65**

[1] The cost of coal shown for the States of Alabama, Florida, Kentucky, and Tennessee is not the total delivered cost of coal to these States and their respective Census Divisions. For more detailed information see footnotes 3, 4, and 5 at the end of Table 31.

* = Number less than 0.5 billion Btu or 0.05 percent.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Origin and Destination of Coal

Table 16. Origin of Coal by State, 2001

State of Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Alabama	10,579	12,136	1.15	0.95	12.74	164.59	39.95
Arizona	13,156	10,929	.51	.47	9.60	119.61	26.14
Colorado	25,112	11,068	.45	.41	8.46	132.35	29.30
Illinois	25,562	11,421	2.21	1.94	8.66	136.63	31.21
Indiana	28,004	11,077	2.12	1.91	9.03	109.89	24.35
Kansas	160	10,573	3.73	3.53	20.10	120.27	25.43
Kentucky	97,180	12,166	1.48	1.22	11.02	147.04	35.78
Louisiana	3,754	6,839	1.15	1.68	13.66	141.66	19.38
Maryland	2,482	11,970	1.69	1.41	17.38	114.43	27.40
Missouri	247	10,940	4.67	4.27	16.58	131.55	28.78
Montana	20,821	9,099	.49	.54	6.27	115.75	21.06
New Mexico	21,254	9,425	.68	.73	18.82	137.99	26.01
North Dakota	23,679	6,537	.74	1.13	9.63	74.36	9.72
Ohio	18,789	11,693	3.23	2.77	10.81	132.57	31.00
Oklahoma	21	12,559	3.01	2.39	10.48	120.87	30.36
Pennsylvania	10,469	12,961	1.79	1.38	8.16	125.24	32.47
Tennessee	1,277	12,749	1.20	.94	8.07	151.15	38.54
Texas	37,032	6,405	1.13	1.76	16.62	128.99	16.52
Utah	18,074	11,863	.52	.44	8.85	115.86	27.49
Virginia	19,647	12,750	.94	.74	10.58	150.31	38.33
West Virginia	70,779	12,190	1.16	.95	12.58	141.39	34.47
Wyoming	304,502	8,689	.32	.36	5.29	100.49	17.46
Subtotal	752,582	9,994	.89	.89	8.85	122.47	24.48
Imported[1]	10,233	11,855	.66	.56	6.71	165.22	39.17
Total	**762,815**	**10,019**	**.89**	**.89**	**8.82**	**123.15**	**24.68**

[1] Imported includes coal from Australia, Colombia, Poland, Russia, South Africa, and Venezuela.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Table 17. Receipts of Lignite by Electric Utility, 2001

Electric Utility	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Basin Electric Power Coop	7,990	6,607	0.69	1.04	9.13	73.43	9.70
Central Louisiana Electric	3,754	6,839	1.15	1.68	13.66	141.66	19.38
Cooperative Power Association	7,670	6,198	.61	.98	11.27	75.17	9.32
Houston Lighting and Power	7,169	6,756	1.20	1.77	15.67	127.07	17.17
Minnkota Power Coop	3,972	6,667	.87	1.30	8.28	71.41	9.52
Montana-Dakota Utilities	3,417	6,938	1.00	1.44	8.92	79.84	11.08
San Miguel Electric	3,282	5,200	2.06	3.97	25.56	79.59	8.28
Southwestern Electric Pwr	3,079	6,568	1.55	2.37	14.61	155.46	20.42
Texas New Mexico Power Co.	1,881	6,758	.93	1.38	16.44	150.68	20.37
TXU Electric Co.	21,622	6,417	.92	1.43	15.88	129.89	16.67
United Power Association	937	6,685	.72	1.08	8.75	74.36	9.94
Total	**64,772**	**6,479**	**.98**	**1.52**	**13.86**	**109.45**	**14.18**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • This table includes all lignite mined in the continental United States and reported on FERC Form 423.

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

Table 18. Receipts, Quality, and Average Delivered Cost of Imported Coal, 1997-2001

Electric Utility Country of Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
2001	**10,233**	**11,855**	**0.66**	**0.56**	**6.71**	**165.22**	**39.17**
Alabama Electric Coop Inc	**589**	**11,466**	**.63**	**.55**	**5.46**	**144.05**	**33.03**
Colombia	589	11,466	.63	.55	5.46	144.05	33.03
Alabama Power Co	**2,664**	**11,720**	**.70**	**.60**	**5.49**	**152.54**	**35.75**
Colombia	2,664	11,720	.70	.60	5.49	152.54	35.75
Carolina Power and Light	**8**	**11,034**	**.50**	**.45**	**5.30**	**254.80**	**56.23**
Colombia	8	11,034	.50	.45	5.30	254.80	56.23
Central Hudson Gas and Electric	**37**	**13,309**	**.61**	**.46**	**7.27**	**156.10**	**41.55**
Venezuela	37	13,309	.61	.46	7.27	156.10	41.55
Duke Power	**112**	**11,514**	**.79**	**.68**	**6.69**	**260.18**	**59.91**
Colombia	112	11,514	.79	.68	6.69	260.18	59.91
Florida Power Corp	**498**	**12,342**	**.67**	**.54**	**7.39**	**191.72**	**47.33**
Venezuela	498	12,342	.67	.54	7.39	191.72	47.33
Georgia Power	**142**	**11,651**	**.78**	**.67**	**6.90**	**210.59**	**49.07**
Colombia	142	11,651	.78	.67	6.90	210.59	49.07
Gulf Power	**857**	**12,209**	**.69**	**.57**	**6.24**	**175.67**	**42.90**
Australia	24	12,136	.57	.47	1.60	157.90	38.33
Colombia	466	11,879	.71	.60	5.61	178.86	42.49
Venezuela	367	12,632	.67	.53	7.35	172.99	43.70
Indiana Michigan Power	**210**	**11,456**	**.52**	**.45**	**11.43**	**211.08**	**48.36**
South Africa	210	11,456	.52	.45	11.43	211.08	48.36
Jacksonville Electric Authority	**1,876**	**11,841**	**.62**	**.53**	**7.69**	**158.55**	**37.55**
Poland	59	11,874	.69	.58	9.50	173.80	41.27
South Africa	62	11,973	.63	.53	9.70	177.40	42.48
Colombia	1,754	11,835	.62	.53	7.56	157.36	37.25
Lakeland Dept of Elec Wtr Utils	**75**	**11,504**	**.61**	**.53**	**8.50**	**216.29**	**49.77**
Colombia	75	11,504	.61	.53	8.50	216.29	49.77
Mississippi Power	**1,895**	**11,470**	**.65**	**.56**	**7.14**	**168.97**	**38.76**
Colombia	1,885	11,469	.65	.57	7.11	168.63	38.68
Russia	11	11,612	.32	.28	11.60	228.20	53.00
Public Serv Co of New Hampshire	**564**	**12,694**	**.65**	**.51**	**6.53**	**169.46**	**43.02**
Venezuela	564	12,694	.65	.51	6.53	169.46	43.02
Savannah Electric and Power	**436**	**12,526**	**.74**	**.59**	**7.45**	**142.18**	**35.62**
Venezuela	436	12,526	.74	.59	7.45	142.18	35.62
Tampa Electric	**269**	**12,478**	**.63**	**.50**	**6.94**	**186.82**	**46.62**
Poland	67	12,629	.52	.41	7.20	198.80	50.21
Colombia	81	11,582	.63	.54	8.80	180.10	41.72
Venezuela	121	12,996	.69	.53	5.55	184.42	47.94
2000	**7,559**	**12,035**	**.63**	**.53**	**5.65**	**148.98**	**35.86**
Alabama Electric Coop Inc	**772**	**11,628**	**.58**	**.50**	**4.57**	**140.24**	**32.61**
Colombia	772	11,628	.58	.50	4.57	140.24	32.61
Alabama Power Co	**2,689**	**11,793**	**.63**	**.54**	**4.67**	**154.80**	**36.51**
Colombia	2,689	11,793	.63	.54	4.67	154.80	36.51
Central Hudson Gas and Electric	**627**	**13,098**	**.62**	**.47**	**6.51**	**157.00**	**41.13**
Venezuela	627	13,098	.62	.47	6.51	157.00	41.13
Gulf Power	**285**	**12,011**	**.59**	**.49**	**4.37**	**142.53**	**34.24**
Colombia	245	11,825	.58	.49	4.28	142.75	33.76
Venezuela	40	13,155	.64	.49	4.90	141.30	37.18
Jacksonville Electric Authority	**1,377**	**11,862**	**.67**	**.57**	**7.59**	**147.00**	**34.88**
Colombia	1,330	11,844	.67	.56	7.55	147.53	34.95
Indonesia	48	12,379	.80	.65	8.60	132.84	32.89
Lakeland Dept of Elec Wtr Utils	**13**	**11,570**	**.71**	**.61**	**4.50**	**168.10**	**38.90**
Colombia	13	11,570	.71	.61	4.50	168.10	38.90

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

Table 18. Receipts, Quality, and Average Delivered Cost of Imported Coal, 1997-2001 (Continued)

Electric Utility Country of Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
2000 (Continued)							
Mississippi Power	720	11,523	0.58	0.50	6.03	148.86	34.31
Colombia	720	11,523	.58	.50	6.03	148.86	34.31
Public Serv Co of New Hampshire	555	13,016	.61	.47	4.99	140.99	36.70
Venezuela	555	13,016	.61	.47	4.99	140.99	36.70
Savannah Electric and Power	467	12,725	.74	.58	7.07	139.02	35.38
Venezuela	467	12,725	.74	.58	7.07	139.02	35.38
Tampa Electric	54	12,949	1.01	.78	6.69	145.09	37.58
Venezuela	54	12,949	1.01	.78	6.69	145.09	37.58
1999	4,969	11,906	.57	.48	5.57	148.61	35.39
Alabama Electric Coop Inc	291	11,513	.54	.47	4.39	139.78	32.19
Colombia	291	11,513	.54	.47	4.39	139.78	32.19
Alabama Power Co	262	11,783	.55	.46	3.36	185.08	43.62
Colombia	262	11,783	.55	.46	3.36	185.08	43.62
Baltimore Gas and Electric	29	12,003	.68	.57	6.00	131.50	31.57
Colombia	29	12,003	.68	.57	6.00	131.50	31.57
Central Hudson Gas and Electric	626	12,890	.65	.50	6.43	160.19	41.30
Colombia	36	13,277	.62	.47	7.27	161.80	42.96
Venezuela	589	12,866	.65	.51	6.38	160.09	41.19
Florida Power Corp	99	12,867	.70	.55	5.99	173.44	44.63
Venezuela	99	12,867	.70	.55	5.99	173.44	44.63
Gulf Power	310	12,483	.64	.51	5.97	148.19	37.00
Colombia	67	11,871	.54	.45	3.68	153.36	36.41
Venezuela	243	12,652	.67	.53	6.60	146.85	37.16
Jacksonville Electric Authority	1,083	11,791	.66	.56	7.51	145.66	34.35
Australia	63	11,506	.67	.58	11.80	124.20	28.58
Colombia	1,020	11,808	.66	.56	7.24	146.95	34.70
Lakeland Dept of Elec Wtr Utils	32	11,570	.71	.61	4.50	168.10	38.90
Colombia	32	11,570	.71	.61	4.50	168.10	38.90
Mississippi Power	717	11,706	.43	.37	4.24	145.59	34.09
Colombia	701	11,696	.43	.36	4.16	145.67	34.07
Venezuela	16	12,165	.75	.62	7.60	142.50	34.67
Public Serv Co of New Hampshire	507	12,990	.67	.52	5.53	142.60	37.05
Venezuela	507	12,990	.67	.52	5.53	142.60	37.05
Savannah Electric and Power	434	12,535	.75	.60	7.24	139.24	34.91
Venezuela	434	12,535	.75	.60	7.24	139.24	34.91
Tampa Electric	539	9,400	.14	.14	2.61	135.44	25.46
Venezuela	151	9,373	.18	.19	6.70	146.56	27.47
Indonesia	388	9,410	.12	.13	1.02	131.12	24.68
United Illuminating Co	35	13,541	.61	.45	4.85	169.29	45.85
Venezuela	35	13,541	.61	.45	4.85	169.29	45.85
Vineland, City of	5	12,842	.78	.61	6.21	193.00	49.57
Poland	4	12,842	.78	.61	6.21	193.00	49.57
Venezuela	1	12,842	.78	.61	6.21	193.00	49.57
1998	5,845	11,967	.61	.51	5.67	155.58	37.24
Cajun Electric Power Coop	303	9,485	.09	.09	.86	187.58	35.58
Indonesia	303	9,485	.09	.09	.86	187.58	35.58
Central Hudson Gas and Electric	594	13,070	.63	.48	7.08	167.26	43.72
Colombia	35	13,309	.62	.47	7.38	169.80	45.20
Venezuela	559	13,055	.63	.48	7.06	167.10	43.63
Central Power and Light	103	12,588	.69	.55	7.68	168.51	42.42
Colombia	60	12,760	.66	.52	6.60	171.04	43.65
Venezuela	42	12,344	.73	.59	9.20	164.80	40.69

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

Table 18. Receipts, Quality, and Average Delivered Cost of Imported Coal, 1997-2001 (Continued)

Electric Utility Country of Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
1998 (Continued)							
City Public Service-San Antonio	67	11,972	0.57	0.47	5.21	190.85	45.70
Colombia	24	11,600	.33	.28	3.80	200.61	46.54
Venezuela	43	12,179	.70	.57	6.00	185.66	45.22
Florida Power Corp	80	12,968	.73	.56	5.67	166.93	43.30
Venezuela	80	12,968	.73	.56	5.67	166.93	43.30
Gulf Power	434	12,415	.69	.56	5.64	149.55	37.13
Colombia	321	12,349	.65	.53	5.25	150.40	37.15
Venezuela	112	12,602	.81	.64	6.74	147.19	37.10
Jacksonville Electric Authority	1,588	11,821	.66	.56	6.84	145.10	34.30
Colombia	1,588	11,821	.66	.56	6.84	145.10	34.30
Lakeland Dept of Elec Wtr Utils	43	12,941	.62	.48	5.70	175.72	45.48
Venezuela	43	12,941	.62	.48	5.70	175.72	45.48
Mississippi Power	174	12,586	.75	.60	6.94	140.44	35.35
Venezuela	174	12,586	.75	.60	6.94	140.44	35.35
New England Power (NEES)	939	12,578	.65	.52	6.18	160.93	40.48
Colombia	467	12,116	.62	.51	5.82	169.87	41.16
Venezuela	472	13,036	.68	.53	6.54	152.70	39.81
Public Serv Co of New Hampshire	366	12,940	.65	.50	5.70	150.49	38.95
Colombia	35	13,188	.64	.49	5.50	172.81	45.58
Venezuela	331	12,914	.65	.51	5.72	148.10	38.25
Public Service Elec and Gas-NJ	39	12,998	.68	.52	5.50	155.30	40.37
Venezuela	39	12,998	.68	.52	5.50	155.30	40.37
Savannah Electric and Power	414	12,492	1.01	.81	7.19	144.63	36.14
Venezuela	414	12,492	1.01	.81	7.19	144.63	36.14
Tampa Electric	597	9,515	.21	.22	1.09	157.06	29.89
Indonesia	597	9,515	.21	.22	1.09	157.06	29.89
United Illuminating Co	106	13,084	.60	.46	5.47	171.02	44.75
Venezuela	106	13,084	.60	.46	5.47	171.02	44.75
1997	4,871	11,848	.68	.57	5.81	159.53	37.80
Central Hudson Gas and Electric	497	13,131	.65	.49	6.63	172.58	45.32
Colombia	147	13,032	.65	.50	7.17	171.28	44.64
Venezuela	350	13,172	.65	.49	6.40	173.12	45.61
Central Power and Light	26	11,665	.47	.40	6.00	173.20	40.41
Colombia	26	11,665	.47	.40	6.00	173.20	40.41
City Public Service-San Antonio	73	11,603	.34	.29	3.89	176.92	41.06
Colombia	73	11,603	.34	.29	3.89	176.92	41.06
Jacksonville Electric Authority	1,385	11,851	.78	.66	7.42	150.14	35.59
Colombia	1,385	11,851	.78	.66	7.42	150.14	35.59
New England Power (NEES)	1,460	12,365	.65	.52	6.01	165.38	40.90
Colombia	1,078	12,112	.63	.52	5.93	166.19	40.26
Venezuela	383	13,078	.68	.52	6.22	163.26	42.70
Public Serv Co of New Hampshire	305	12,345	.64	.52	5.98	164.66	40.66
Colombia	35	13,231	.63	.48	6.70	160.12	42.37
Venezuela	229	12,217	.67	.55	6.13	160.74	39.27
Indonesia	41	12,300	.49	.40	4.50	190.73	46.92
Savannah Electric and Power	279	11,949	1.28	1.07	7.72	135.13	32.29
Venezuela	279	11,949	1.28	1.07	7.72	135.13	32.29
Tacoma Dept of Public Utilities	10	10,144	.43	.42	12.25	171.45	34.79
Canada	10	10,144	.43	.42	12.25	171.45	34.79
Tampa Electric	800	9,859	.43	.44	1.59	159.59	31.47
Venezuela	59	12,953	1.47	1.13	3.50	130.20	33.73
Indonesia	741	9,614	.35	.37	1.44	162.72	31.29

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

Table 18. Receipts, Quality, and Average Delivered Cost of Imported Coal, 1997-2001 (Continued)

Electric Utility Country of Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
1997 (Continued)							
United Illuminating Co	35	13,387	0.64	0.48	4.30	169.60	45.41
Venezuela	35	13,387	.64	.48	4.30	169.60	45.41

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Because of electric utilities' divestiture of plants, year-to-year comparisons may not be valid.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 19. Receipts of Appalachian Region Coal by Electric Utility, 2001

Electric Utility	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Alabama Electric Coop Inc	598	11,980	1.62	1.35	12.17	134.37	32.19
Alabama Power Co	9,811	12,148	1.11	.92	12.78	165.73	40.27
American Municipal Power Ohio	758	11,804	1.93	1.63	14.53	120.42	28.43
Appalachian Power	11,234	12,162	.75	.61	12.40	129.29	31.45
Atlantic City Electric	187	12,859	1.66	1.29	9.47	233.21	59.98
Cardinal Operating Co (AEP)	4,017	12,192	1.40	1.15	12.06	140.70	34.31
Carolina Power and Light	9,375	12,409	.85	.68	10.94	164.47	40.82
Cedar Falls Utilities	17	13,148	1.51	1.15	6.30	186.11	48.94
Central Illinois Light	358	11,860	1.25	1.05	6.59	224.41	53.23
Central Operating Co (AEP)	2,476	12,066	.94	.78	12.31	128.57	31.03
Cincinnati Gas and Electric Co	10,621	12,051	2.24	1.85	11.32	117.15	28.24
Columbia Water and Light	30	13,408	1.10	.82	6.13	206.58	55.40
Columbus Southern Power Co (AEP)	4,045	11,674	2.40	2.05	9.55	129.52	30.24
Consumers Power	3,083	12,371	.79	.63	11.16	168.06	41.58
Dayton Power and Light Co	7,876	11,606	.83	.71	14.29	129.47	30.05
Delmarva Power and Light	24	12,572	.67	.53	11.56	216.91	54.54
Detroit Edison Co	5,757	12,915	1.32	1.02	7.73	131.98	34.09
Duke Power	17,283	12,251	.88	.71	11.79	156.68	38.39
East Kentucky Power Coop	4,060	12,101	.94	.78	11.54	134.21	32.48
Florida Power Corp	4,921	12,494	.82	.66	10.15	200.98	50.22
Gainesville Regional Utilities	462	13,054	.70	.54	7.11	194.44	50.76
Georgia Power	26,868	12,463	.94	.76	10.81	167.61	41.78
Grand Haven Light & Power	205	12,762	2.35	1.84	10.07	133.29	34.02
Gulf Power	252	12,673	.94	.74	9.62	173.93	44.08
Hamilton, City of	150	12,160	.98	.80	12.52	147.52	35.88
Holland Board of Public Wks	114	12,850	.84	.65	8.41	164.45	42.27
Indiana Michigan Power	2,776	12,053	1.35	1.12	10.82	120.33	29.01
Indiana-Kentucky Electric Corp	1,163	13,246	1.38	1.04	7.09	149.57	39.62
Jacksonville Electric Authority	1,598	12,613	1.41	1.12	14.91	162.49	40.99
Jamestown Bd of Public Utilities	76	12,573	1.82	1.45	10.75	144.20	36.26
Kentucky Power (AEP)	3,236	11,990	.92	.77	10.54	102.76	24.64
Kentucky Utilities	6,103	12,067	1.61	1.33	12.16	119.32	28.80
Lakeland Dept of Elec Wtr Utils	255	12,786	1.25	.97	9.31	178.71	45.70
Lansing Board of Water and Light	362	12,656	.94	.75	9.60	166.99	42.27
Louisville Gas and Electric	2,585	11,725	3.38	2.88	13.91	89.31	20.94
Manitowoc Public Utilities	124	13,074	1.63	1.24	7.33	175.32	45.84
Marquette Bd of Light and Power	25	13,247	.83	.62	7.67	206.14	54.62
Michigan South Central Power	173	11,953	2.72	2.28	11.77	169.45	40.51
Mississippi Power	10	12,621	.70	.55	9.90	182.10	45.97
Monongahela Power (APS)	3,561	12,386	2.53	2.04	11.22	109.61	27.15
Northern Indiana Public Service	740	13,274	2.09	1.57	7.64	130.44	34.63
Ohio Power	15,591	11,899	2.38	2.00	11.36	143.01	34.03
Ohio Valley Electric Corp	2,344	12,759	2.32	1.82	8.64	105.31	26.87
Orlando Utilities Comm	2,544	12,723	1.20	.94	9.18	166.09	42.26
Orrville, City of	180	11,631	3.89	3.34	10.01	102.95	23.95
Painesville Electric Light Dept	88	12,376	2.50	2.02	7.48	137.72	34.09
Philadelphia Electric	208	13,105	1.91	1.46	8.10	155.31	40.71
Public Serv Co of New Hampshire	1,136	13,203	1.69	1.28	6.87	165.90	43.81
Public Service Co of Indiana	498	13,124	2.27	1.73	7.13	114.33	30.01
Richmond Power and Light	205	12,063	2.24	1.86	11.56	151.75	36.61
Rochester Gas and Electric Corp	660	13,133	2.06	1.57	7.63	140.50	36.90
Savannah Electric and Power	287	12,477	.72	.57	154.29	167.45	41.79
Seminole Electric Coop	380	13,011	2.04	1.57	8.34	185.24	48.20
South Carolina Electric and Gas	6,695	12,552	1.05	.84	8.86	155.77	39.10
South Carolina Public Serv Auth	7,876	12,645	1.26	1.00	9.37	154.99	39.20
South Mississippi Elec Pwr Assn	1,027	12,279	.96	.79	11.62	152.51	37.45
Southern Indiana Gas and Elec	2	10,628	.78	.73	18.00	158.40	33.67
Tampa Electric	309	12,632	1.17	.92	8.58	184.14	46.52
Tennessee Valley Authority	10,281	12,426	1.13	.91	10.97	138.13	34.33
Vineland, City of	27	13,051	.92	.71	9.54	186.97	48.80
Virginia Electric and Power	11,701	12,546	1.24	.99	11.90	151.80	38.09
West Penn Power (APS)	542	12,821	2.20	1.71	9.29	107.01	27.44
Wisconsin Electric Power	870	13,001	1.35	1.04	7.95	148.08	38.50
Wisconsin Power and Light	25	14,065	.64	.45	5.31	153.75	43.25
Wisconsin Public Service Corp	18	13,412	.81	.60	6.32	272.31	73.04
Wyandotte Dept of Mun Service	112	12,502	.83	.66	11.33	164.42	41.11
Total	**210,976**	**12,300**	**1.32**	**1.08**	**11.32**	**146.65**	**36.08**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • The Appalachian Region includes Alabama, eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

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

Table 20. Receipts of Interior Region Non-Lignite Coal by Electric Utility, 2001

Electric Utility	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Alabama Electric Coop Inc	309	11,974	1.72	1.44	10.84	138.37	33.14
Alabama Power Co	952	12,216	1.44	1.18	6.55	120.75	29.50
Ameren CIPS	2,969	10,487	1.49	1.42	8.36	128.11	26.87
Ameren-UE	1,005	11,540	2.33	2.02	8.98	129.05	29.78
Big Rivers Electric Corp	265	11,858	3.23	2.73	11.19	90.30	21.42
Cedar Falls Utilities	21	11,698	1.33	1.14	8.39	202.27	47.32
Central Elec Power Coop-Missouri	81	11,261	2.37	2.10	8.27	137.33	30.93
Central Illinois Light	2,003	10,940	2.37	2.17	7.88	178.54	39.07
Central Iowa Power Coop	180	11,243	2.94	2.62	10.49	116.87	26.28
Cincinnati Gas and Electric Co	338	11,581	2.18	1.88	8.46	124.55	28.85
City of Independence Pwr and Lt	109	11,252	2.74	2.43	11.89	174.20	39.20
City Utilities of Springfield	120	12,037	1.48	1.23	6.32	140.34	33.79
Dairyland Power Cooperative	644	11,917	1.42	1.19	6.13	144.77	34.51
Empire Dist Electric	17	12,586	3.08	2.45	10.32	111.44	28.05
Gulf Power	2,072	12,091	1.20	.99	6.33	151.62	36.66
Hoosier Energy R E C	3,736	11,154	2.82	2.52	9.94	102.93	22.96
Indiana Michigan Power	196	11,570	1.16	1.00	4.73	151.71	35.11
Indianapolis Power and Light	4,180	11,124	2.00	1.80	8.68	97.49	21.69
Interstate Power	25	11,690	1.04	.89	4.83	174.62	40.82
Kansas City Power and Light	327	10,782	4.69	4.35	19.19	118.60	25.58
Kentucky Utilities	276	11,543	2.14	1.86	11.91	129.25	29.84
Louisville Gas and Electric	5,117	11,231	3.36	2.99	11.92	95.25	21.40
Madison Gas and Electric	199	11,019	1.51	1.37	9.10	152.70	33.65
Manitowoc Public Utilities	19	10,922	.82	.75	8.67	161.33	35.24
Mississippi Power	401	12,071	1.42	1.18	6.42	153.48	37.05
Northern Indiana Public Service	2,808	10,960	2.94	2.68	8.61	133.35	29.23
Owensboro Municipal Utilities	1,139	10,718	3.25	3.03	11.62	90.95	19.49
Public Service Co of Indiana	16,044	10,974	1.63	1.49	9.07	110.15	24.17
Richmond Power and Light	116	11,145	1.79	1.61	8.10	153.93	34.31
Rochester Dept Public Utilities	184	11,680	.97	.83	7.42	181.47	42.39
Seminole Electric Coop	2,921	12,097	2.89	2.39	8.50	179.54	43.44
Southern Illinois Power Coop	960	10,168	2.97	2.93	16.57	90.44	18.39
Southern Indiana Gas and Elec	2,159	11,409	3.27	2.86	9.19	100.95	23.03
Springfield Wtr Lt and Pwr Dept	1,222	10,449	2.77	2.65	9.25	116.42	24.33
Tampa Electric	6,073	11,791	2.55	2.16	8.74	153.71	36.25
Tennessee Valley Authority	15,032	11,479	3.06	2.66	12.86	108.41	24.89
Total	**74,221**	**11,279**	**2.44**	**2.16**	**9.97**	**120.16**	**27.11**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • The Interior Region includes Arkansas, Illinois, Indiana, Iowa, Kansas, western Kentucky, Missouri, Oklahoma, and Texas. • This table excludes all lignite receipts.

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

Table 21. Receipts of Western Region Non-Lignite Coal by Electric Utility, 2001

Electric Utility	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Alabama Power Co	10,784	8,799	0.26	0.29	4.84	110.46	19.44
Ameren CIPS	3,645	8,784	.25	.29	4.94	111.02	19.50
Ameren-UE	17,792	8,654	.34	.40	5.29	95.77	16.58
Ames, City of	228	8,863	.20	.22	4.34	144.34	25.59
Appalachian Power	624	8,851	.24	.27	4.45	138.70	24.55
Arizona Electric Power Coop Inc	1,404	9,629	.70	.73	14.13	143.92	27.72
Arizona Public Service	7,426	9,280	.64	.69	18.04	105.75	19.63
Arkansas Power and Light	12,681	8,745	.27	.31	4.58	78.54	13.74
Associated Electric Coop	9,554	8,910	.20	.22	4.26	89.37	15.93
Basin Electric Power Coop	8,284	8,353	.32	.38	5.19	47.99	8.02
Black Hills Corporation	538	8,091	.62	.76	7.05	46.84	7.58
Cardinal Operating Co (AEP)	286	8,885	.23	.26	4.44	161.78	28.75
Central Elec Power Coop-Missouri	227	8,916	.20	.23	4.26	107.53	19.18
Central Illinois Light	11	11,691	.53	.45	7.80	175.45	41.02
Central Louisiana Electric	1,848	8,788	.41	.46	5.28	137.21	24.12
Central Power and Light	1,695	9,905	.33	.34	5.94	138.82	27.50
City Public Service-San Antonio	5,938	8,447	.32	.38	5.45	101.01	17.07
City Utilities of Springfield	1,636	9,020	.20	.22	4.32	115.75	20.88
Colorado Springs Dept Pub Utils	1,957	9,848	.37	.37	6.71	83.98	16.54
Consumers Power	5,935	8,837	.31	.35	5.43	109.25	19.31
Dairyland Power Cooperative	1,882	9,145	.25	.28	4.51	112.08	20.50
Deseret Generation & Trans	2,028	9,929	.40	.40	10.15	156.72	31.12
Detroit Edison Co	14,428	9,164	.30	.33	4.62	116.98	21.44
Electric Energy	5,113	8,840	.23	.26	4.75	86.90	15.36
Empire Dist Electric	523	9,390	.23	.25	4.67	115.11	21.62
Florida Power Corp	20	12,159	.38	.31	5.21	188.74	45.90
Fremont Dept of Public Utilities	323	8,940	.23	.25	4.53	98.20	17.56
Georgia Power	6,628	8,799	.29	.33	5.22	158.10	27.82
Grand Island Utilities	449	8,784	.29	.33	5.44	72.20	12.68
Grand River Dam Authority	3,489	8,445	.34	.40	5.22	88.60	14.96
Gulf Power	132	11,965	.47	.39	9.04	191.27	45.77
Gulf States Utilities	2,511	8,784	.38	.43	5.22	113.69	19.97
Hastings Utilities	332	8,763	.29	.33	5.63	67.30	11.80
Holland Board of Public Wks	32	11,494	.92	.80	7.65	190.00	43.68
Houston Lighting and Power	9,254	8,593	.38	.44	5.28	175.32	30.13
Indiana Michigan Power	8,722	8,826	.26	.30	4.63	112.19	19.80
Indiana-Kentucky Electric Corp	2,698	8,880	.22	.25	4.76	106.19	18.86
Interstate Power	1,659	9,040	.33	.36	5.75	84.82	15.34
IES Utilities	5,282	8,611	.34	.39	5.61	89.46	15.41
Kansas City Bd Public Utilities	1,572	8,290	.36	.43	5.21	80.43	13.34
Kansas City Power and Light	9,118	8,739	.33	.38	5.46	78.81	13.77
Kansas Power and Light Co	13,942	8,688	.37	.43	5.28	115.59	20.09
Kentucky Utilities	1,178	8,727	.30	.35	6.03	110.65	19.31
Lansing Board of Water and Light	1,003	8,835	.31	.35	5.71	117.98	20.85
Los Angeles Dept of Wtr and Pwr	5,350	11,819	.51	.44	8.97	136.41	32.24
Lower Colorado River Authority	6,426	8,475	.33	.39	8.44	90.73	15.38
Manitowoc Public Utilities	15	12,116	.62	.51	8.00	157.80	38.24
Marquette Bd of Light and Power	169	9,319	.33	.36	4.09	124.90	23.28
MidAmerican Energy	13,607	8,603	.33	.38	5.13	74.96	12.90
Minnesota Power and Light	4,268	9,053	.56	.61	6.65	117.73	21.31
Mississippi Power	2,790	11,627	.53	.45	9.31	165.44	38.47
Muscatine Power and Water	951	8,278	.61	.73	6.30	87.73	14.53
Nebraska Public Power System	6,606	8,578	.31	.36	4.67	51.79	8.89
Nevada Power	2,154	11,845	.59	.50	8.83	118.13	27.98
Northern Indiana Public Service	5,585	9,122	.35	.38	5.55	121.57	22.18
Northern States Power	13,255	8,825	.44	.49	6.65	94.62	16.70
Ohio Power	7	8,927	.23	.26	4.80	143.70	25.66
Ohio Valley Electric Corp	211	8,634	.33	.38	5.29	127.84	22.08
Oklahoma Gas and Electric	8,609	8,768	.25	.29	5.06	78.20	13.71
Omaha Public Power District	5,239	8,546	.31	.37	5.54	57.85	9.89
Otter Tail Power	2,693	8,583	.33	.39	5.25	107.85	18.51
PacifiCorp	22,216	9,873	.54	.55	8.18	87.36	17.25
Plains Elec Gen and Trans Coop	533	9,159	.83	.91	18.41	135.12	24.75
Platte River Authority	1,312	8,832	.23	.26	5.12	61.65	10.89
Portland General Electric	2,583	8,706	.38	.43	6.21	110.99	19.33
Public Serv Co of New Hampshire	10	9,465	.34	.36	4.10	207.10	39.20
Public Serv Co of Oklahoma	3,272	8,743	.39	.45	5.29	115.91	20.27
Public Service Co of Colorado	10,484	9,585	.39	.40	6.67	89.18	17.09
Public Service Co of New Mexico	6,118	9,542	.70	.73	22.49	184.67	35.25
Rochester Dept Public Utilities	7	11,000	.50	.45	7.20	260.80	57.38
Salt River Project	11,689	10,562	.51	.48	10.46	119.84	25.32
Sierra Pacific Power	968	11,237	.40	.36	8.49	157.44	35.38
Sikeston Brd of Mun Utilities	802	8,770	.34	.39	5.49	108.55	19.04
Southern California Edison	4,933	10,963	.49	.45	10.02	123.70	27.12
Southwestern Electric Pwr	8,804	8,519	.33	.38	4.72	149.09	25.40

See footnotes at end of table.

Table 21. Receipts of Western Region Non-Lignite Coal by Electric Utility, 2001 (Continued)

Electric Utility	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Southwestern Public Service	8,563	8,781	0.27	0.30	5.48	137.93	24.22
St Joseph Light and Power	423	9,719	.34	.35	5.71	113.80	22.12
Sunflower Electric Power Corp	1,363	8,468	.31	.36	5.28	104.90	17.76
Tampa Electric	679	8,729	.25	.28	4.70	144.40	25.21
Tennessee Valley Authority	11,242	10,612	.41	.38	7.07	124.09	26.34
Texas Municipal Power	2,089	8,449	.31	.37	5.47	134.41	22.71
TXU Electric Co	5,675	8,438	.31	.37	5.57	137.12	23.14
Tri-State G & T Assn Inc.	4,920	10,217	.42	.41	7.00	108.39	22.15
Tucson Electric Power Co	3,670	9,437	.83	.87	16.96	141.52	26.71
UtiliCorp United Inc	1,683	9,725	.33	.34	5.90	93.30	18.15
West Texas Utilities	2,084	8,449	.35	.41	5.38	133.33	22.53
Western Farmers Electric Coop	1,748	8,743	.28	.32	4.82	108.00	18.88
Wisconsin Electric Power	10,997	9,084	.30	.33	5.41	97.80	17.77
Wisconsin Power and Light	7,456	8,737	.32	.37	5.26	104.71	18.30
Wisconsin Public Service Corp	3,528	8,870	.26	.29	5.03	103.66	18.39
Wyandotte Dept of Mun Service	15	12,589	.70	.56	7.23	216.40	54.49
Total	**402,613**	**9,115**	**.37**	**.40**	**6.55**	**107.39**	**19.58**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • The Western Region includes Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming. • This table excludes all lignite receipts.

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

Table 22. Destination and Origin of Coal by State, 2001

Destination Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Alabama[1]	**29,866**	**10,850**	**0.92**	**0.85**	**8.84**	**141.07**	**30.61**
Alabama	10,391	12,137	1.14	.94	12.75	163.93	39.79
Colorado	9	12,250	.65	.53	11.00	169.55	41.54
Illinois	1,359	12,170	1.88	1.54	7.46	123.69	30.11
Kentucky	3,004	11,814	2.42	2.05	12.51	131.22	31.00
Pennsylvania	5	13,355	2.38	1.78	7.60	112.20	29.97
Virginia	148	12,461	.91	.73	9.44	126.96	31.64
West Virginia	912	12,065	.79	.66	13.38	168.75	40.72
Wyoming	10,784	8,799	.26	.29	4.84	110.46	19.44
Imported	3,254	11,674	.69	.59	5.48	151.03	35.26
Arizona	**19,297**	**10,175**	**.58**	**.57**	**12.37**	**124.97**	**25.43**
Arizona	8,223	10,909	.53	.48	9.35	117.14	25.56
Colorado	858	10,762	.39	.36	7.16	178.53	38.43
Montana	157	9,388	.32	.34	3.91	125.24	23.51
New Mexico	9,711	9,565	.65	.67	15.77	127.13	24.32
Wyoming	348	8,781	.50	.57	5.50	126.81	22.27
Arkansas	**14,582**	**8,708**	**.28**	**.32**	**4.61**	**87.46**	**15.23**
Wyoming	14,582	8,708	.28	.32	4.61	87.46	15.23
Colorado	**18,673**	**9,726**	**.38**	**.39**	**6.65**	**92.19**	**17.93**
Colorado	10,388	10,612	.44	.42	8.06	103.58	21.98
Wyoming	8,285	8,615	.31	.36	4.88	74.60	12.85
Delaware	**24**	**12,572**	**.67**	**.53**	**11.56**	**216.91**	**54.54**
Kentucky	10	12,473	.65	.52	10.23	248.18	61.91
West Virginia	14	12,642	.69	.55	12.50	195.00	49.30
Florida[1]	**26,192**	**12,146**	**1.54**	**1.27**	**8.88**	**171.81**	**41.74**
Alabama	3	11,810	.99	.84	14.00	185.34	43.78
Colorado	152	11,991	.46	.38	8.54	190.93	45.79
Illinois	7,479	11,881	2.16	1.81	7.90	157.06	37.32
Indiana	867	11,338	3.17	2.80	8.79	144.26	32.71
Kentucky	10,572	12,587	1.52	1.21	9.81	177.92	44.79
Pennsylvania	381	12,985	1.91	1.47	7.42	152.07	39.49
Virginia	38	13,052	1.34	1.03	9.73	222.31	58.03
West Virginia	2,447	12,303	.83	.67	11.62	205.45	50.56
Wyoming	679	8,729	.25	.28	4.70	144.40	25.21
Imported	3,574	12,040	.65	.54	7.26	170.81	41.13
Georgia	**34,362**	**11,754**	**.81**	**.69**	**10.87**	**166.07**	**39.04**
Alabama	137	12,124	1.56	1.29	12.14	211.46	51.28
Colorado	49	11,039	.49	.44	10.33	227.14	50.15
Kentucky	16,151	12,409	.98	.79	10.53	168.08	41.72
Virginia	7,075	12,688	.96	.76	10.91	155.83	39.54
West Virginia	3,793	12,287	.72	.58	22.66	186.68	45.88
Wyoming	6,579	8,783	.29	.33	5.18	157.46	27.66
Imported	578	12,311	.75	.61	7.31	158.13	38.93
Illinois	**16,281**	**9,654**	**1.10**	**1.14**	**6.91**	**119.16**	**23.01**
Colorado	11	11,691	.53	.45	7.80	175.45	41.02
Illinois	6,780	10,521	2.13	2.03	9.51	136.30	28.68
Indiana	365	11,320	2.61	2.31	8.87	126.27	28.59
Kentucky	249	11,308	1.10	.97	6.47	213.64	48.32
Pennsylvania	119	13,098	1.58	1.21	6.98	244.22	63.98
Wyoming	8,758	8,816	.24	.27	4.83	96.90	17.09
Indiana	**51,840**	**10,518**	**1.43**	**1.36**	**7.74**	**113.66**	**23.91**
Colorado	168	12,074	.45	.37	8.71	146.58	35.40
Illinois	4,444	11,048	2.39	2.17	9.37	116.21	25.68
Indiana	24,783	11,055	2.02	1.83	9.01	108.14	23.91
Kentucky	828	11,663	.75	.64	10.86	142.07	33.14
Ohio	268	11,060	3.64	3.29	12.58	123.69	27.36
Pennsylvania	362	12,677	2.30	1.81	9.57	122.36	31.03
Utah	273	12,100	.47	.39	8.89	164.40	39.79
Virginia	1,065	13,837	.74	.53	5.55	159.30	44.09
West Virginia	2,874	12,497	1.84	1.47	9.83	114.33	28.58
Wyoming	16,564	8,848	.28	.31	4.85	112.82	19.96
Imported	210	11,456	.52	.45	11.43	211.08	48.36

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

Table 22. Destination and Origin of Coal by State, 2001 (Continued)

Destination Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Iowa	**21,970**	**8,658**	**0.37**	**0.42**	**5.38**	**81.36**	**14.09**
Colorado	481	11,481	.43	.37	7.61	136.65	31.38
Illinois	201	11,311	2.77	2.45	10.04	125.05	28.29
Indiana	16	11,569	.85	.73	4.43	173.70	40.19
Kentucky	10	11,477	1.43	1.25	10.40	200.00	45.91
Pennsylvania	17	13,148	1.51	1.15	6.30	186.11	48.94
Utah	49	11,337	.42	.37	8.48	128.72	29.19
Wyoming	21,197	8,556	.34	.40	5.28	78.70	13.47
Kansas	**21,286**	**8,686**	**.43**	**.49**	**5.53**	**104.76**	**18.20**
Colorado	1,320	11,023	.47	.43	8.52	153.74	33.89
Kansas	160	10,573	3.73	3.53	20.10	120.27	25.43
Missouri	167	10,983	5.61	5.11	18.32	117.06	25.71
Montana	200	8,773	.31	.35	5.50	105.95	18.59
Oklahoma	17	12,586	3.08	2.45	10.32	111.44	28.05
Wyoming	19,421	8,487	.35	.41	5.09	100.12	16.99
Kentucky[1]	**33,844**	**11,460**	**2.15**	**1.87**	**12.21**	**110.36**	**25.29**
Colorado	2,512	11,936	.41	.34	8.13	137.92	32.92
Illinois	448	12,238	2.93	2.39	9.35	115.67	28.31
Indiana	1,411	11,200	3.35	2.99	10.26	96.21	21.55
Kentucky	19,095	11,367	2.44	2.14	13.55	106.30	24.17
Ohio	201	11,935	3.21	2.69	11.52	105.75	25.24
Pennsylvania	93	12,814	2.48	1.93	8.40	100.11	25.66
Utah	181	11,625	.51	.44	9.25	151.60	35.25
West Virginia	8,223	12,057	2.13	1.77	12.26	112.58	27.15
Wyoming	1,680	8,739	.30	.34	5.86	108.03	18.88
Louisiana	**8,113**	**7,885**	**.74**	**.94**	**9.14**	**130.89**	**20.64**
Louisiana	3,754	6,839	1.15	1.68	13.66	141.66	19.38
Wyoming	4,359	8,786	.39	.44	5.24	123.66	21.73
Michigan	**33,466**	**10,220**	**.57**	**.56**	**6.24**	**127.48**	**26.06**
Colorado	759	12,079	.58	.48	9.67	149.42	36.10
Kentucky	4,059	12,809	.97	.76	8.39	154.38	39.55
Montana	9,120	9,415	.37	.39	4.52	127.89	24.08
Ohio	158	11,870	2.84	2.40	12.17	170.96	40.58
Pennsylvania	2,074	12,999	1.59	1.22	7.21	121.27	31.53
Utah	25	12,605	.77	.61	7.38	209.89	52.91
Virginia	96	12,867	.82	.64	8.25	154.61	39.79
West Virginia	3,622	12,467	1.09	.87	10.74	152.21	37.95
Wyoming	13,552	8,814	.26	.30	5.11	104.67	18.45
Minnesota	**18,059**	**8,909**	**.47**	**.53**	**6.60**	**101.78**	**18.13**
Illinois	120	12,119	1.04	.86	6.47	186.94	45.31
Indiana	64	10,850	.85	.79	9.20	169.91	36.87
Montana	10,545	8,890	.61	.68	7.84	104.56	18.59
Wyoming	7,330	8,866	.26	.29	4.80	95.14	16.87
Mississippi	**6,123**	**11,718**	**.70**	**.59**	**8.84**	**163.46**	**38.31**
Alabama	35	12,390	.75	.60	11.29	188.82	46.79
Colorado	2,736	11,683	.53	.46	9.38	165.72	38.72
Illinois	401	12,071	1.42	1.18	6.42	153.48	37.05
Kentucky	863	12,175	.96	.79	11.85	151.40	36.87
Virginia	139	12,918	1.02	.79	10.18	152.23	39.33
Wyoming	54	8,768	.29	.33	5.70	146.20	25.64
Imported	1,895	11,470	.65	.56	7.14	168.97	38.76
Missouri	**39,039**	**8,918**	**.36**	**.41**	**5.17**	**95.76**	**17.08**
Colorado	57	12,047	.45	.38	9.17	185.69	44.74
Illinois	1,230	11,587	2.26	1.95	8.66	132.44	30.69
Kentucky	30	13,395	1.11	.83	6.18	206.83	55.41
Missouri	80	10,851	2.71	2.50	12.94	162.11	35.18
Oklahoma	4	12,442	2.68	2.16	11.16	162.36	40.40
Utah	514	12,492	.44	.35	7.14	117.61	29.38
Wyoming	37,123	8,767	.29	.33	5.00	93.21	16.34
Montana	**307**	**6,539**	**.53**	**.82**	**9.51**	**94.93**	**12.42**
Montana	307	6,539	.53	.82	9.51	94.93	12.42

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

Table 22. Destination and Origin of Coal by State, 2001 (Continued)

Destination Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Nebraska	**12,949**	**8,586**	**0.31**	**0.36**	**5.07**	**56.57**	**9.71**
Wyoming	12,949	8,586	.31	.36	5.07	56.57	9.71
Nevada	**8,055**	**11,232**	**.51**	**.45**	**9.51**	**126.19**	**28.35**
Arizona	4,933	10,963	.49	.45	10.02	123.70	27.12
Utah	3,095	11,673	.53	.46	8.73	129.25	30.17
Wyoming	27	9,714	.48	.49	8.24	217.21	42.20
New Hampshire	**1,710**	**13,013**	**1.34**	**1.03**	**6.74**	**167.22**	**43.52**
Montana	10	9,465	.34	.36	4.10	207.10	39.20
Ohio	18	13,225	2.12	1.60	5.80	215.95	57.12
Pennsylvania	956	13,181	1.61	1.22	6.87	165.59	43.65
West Virginia	163	13,331	2.09	1.57	6.97	162.33	43.28
Imported	564	12,694	.65	.51	6.53	169.46	43.02
New Jersey	**214**	**12,883**	**1.57**	**1.22**	**9.48**	**227.37**	**58.58**
Maryland	23	12,879	2.37	1.84	10.80	194.80	50.18
Pennsylvania	10	12,636	.49	.39	6.90	279.00	70.51
West Virginia	181	12,897	1.53	1.19	9.46	228.55	58.95
New Mexico	**11,543**	**9,308**	**.72**	**.77**	**21.39**	**147.38**	**27.43**
New Mexico	11,543	9,308	.72	.77	21.39	147.38	27.43
New York	**772**	**13,086**	**1.97**	**1.50**	**7.92**	**141.60**	**37.06**
Pennsylvania	354	12,900	1.80	1.40	8.58	153.74	39.67
West Virginia	381	13,237	2.26	1.71	7.37	129.21	34.21
Imported	37	13,309	.61	.46	7.27	156.10	41.55
North Carolina	**25,944**	**12,303**	**.86**	**.70**	**11.47**	**159.30**	**39.20**
Kentucky	10,907	12,343	.98	.79	10.87	161.70	39.92
Tennessee	42	12,934	1.00	.77	7.41	222.28	57.50
Virginia	1,505	12,533	.99	.79	10.91	167.87	42.08
West Virginia	13,370	12,249	.75	.61	12.07	155.28	38.04
Imported	120	11,480	.77	.67	6.59	259.82	59.66
North Dakota	**24,223**	**6,570**	**.73**	**1.12**	**9.53**	**74.15**	**9.74**
North Dakota	23,679	6,537	.74	1.13	9.63	74.36	9.72
Wyoming	544	8,026	.43	.54	5.41	66.72	10.71
Ohio	**39,764**	**11,823**	**2.07**	**1.75**	**11.63**	**130.96**	**30.97**
Illinois	44	12,359	2.43	1.96	8.34	145.25	35.90
Indiana	109	11,011	1.53	1.39	8.84	124.41	27.40
Kentucky	5,845	11,732	.95	.81	13.37	126.40	29.66
Ohio	17,753	11,682	3.22	2.76	10.79	133.24	31.13
Pennsylvania	987	13,036	2.31	1.77	7.97	99.45	25.93
Virginia	454	13,802	.72	.52	5.64	128.36	35.43
West Virginia	14,076	12,001	1.17	.98	12.69	132.08	31.70
Wyoming	496	8,779	.27	.31	4.80	147.62	25.92
Oklahoma	**17,118**	**8,695**	**.30**	**.34**	**5.11**	**90.57**	**15.75**
Wyoming	17,118	8,695	.30	.34	5.11	90.57	15.75
Oregon	**2,583**	**8,706**	**.38**	**.43**	**6.21**	**110.99**	**19.33**
Utah	311	11,880	.54	.45	11.48	115.89	27.54
Wyoming	2,272	8,272	.35	.43	5.49	110.03	18.20
Pennsylvania	**750**	**12,900**	**2.12**	**1.64**	**8.96**	**120.63**	**31.12**
Pennsylvania	526	12,922	2.16	1.67	8.86	119.13	30.79
West Virginia	224	12,848	2.01	1.56	9.20	124.15	31.90
South Carolina	**15,405**	**12,586**	**1.15**	**.92**	**9.26**	**156.52**	**39.40**
Kentucky	12,759	12,631	1.17	.93	9.17	155.38	39.25
Pennsylvania	9	12,980	2.38	1.83	7.70	186.80	48.49
Tennessee	851	12,779	1.37	1.07	7.05	157.02	40.13
Virginia	982	12,377	1.05	.84	11.36	173.45	42.94
West Virginia	804	11,922	.79	.66	10.59	153.37	36.57
South Dakota	**2,182**	**8,427**	**.33**	**.39**	**5.49**	**103.27**	**17.41**
Wyoming	2,182	8,427	.33	.39	5.49	103.27	17.41

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

Table 22. Destination and Origin of Coal by State, 2001 (Continued)

Destination Origin	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Tennessee [1]	**24,238**	**11,605**	**1.36**	**1.17**	**8.99**	**121.98**	**28.31**
Alabama	12	10,500	1.40	1.33	20.00	123.33	25.90
Colorado	2,001	11,994	.53	.44	9.00	131.14	31.46
Illinois	2,560	12,239	2.57	2.10	8.75	119.83	29.33
Indiana	43	11,683	1.18	1.01	5.00	141.30	33.02
Kentucky	9,395	12,068	1.87	1.55	10.53	122.88	29.66
Pennsylvania	874	13,168	2.52	1.91	7.74	111.34	29.32
Tennessee	383	12,661	.85	.67	10.42	129.97	32.91
Utah	1,653	12,135	.61	.50	8.75	137.73	33.43
Virginia	2,700	12,639	.96	.76	10.36	123.54	31.23
West Virginia	232	11,864	1.85	1.56	12.37	191.67	45.48
Wyoming	4,385	8,814	.28	.32	5.05	102.79	18.12
Texas	**85,660**	**7,651**	**.67**	**.88**	**10.44**	**133.24**	**20.39**
Colorado	977	10,783	.41	.38	6.92	143.29	30.90
Montana	1	8,746	.66	.75	8.71	123.70	21.64
Texas	37,032	6,405	1.13	1.76	16.62	128.99	16.52
Wyoming	47,650	8,555	.32	.38	5.71	135.45	23.17
Utah	**13,709**	**11,559**	**.49**	**.42**	**9.12**	**112.30**	**25.96**
Colorado	2,028	9,929	.40	.40	10.15	156.72	31.12
Utah	11,681	11,842	.50	.42	8.94	105.84	25.07
Virginia	**10,825**	**12,643**	**1.02**	**.81**	**11.02**	**159.32**	**40.29**
Kentucky	2,613	12,751	1.18	.93	9.09	187.48	47.81
Maryland	273	10,033	2.75	2.75	29.02	96.82	19.43
Pennsylvania	76	12,830	1.40	1.09	11.10	228.62	58.66
Virginia	5,402	12,703	.92	.72	11.58	147.61	37.50
West Virginia	2,461	12,681	.87	.69	9.87	158.34	40.16
West Virginia	**23,795**	**12,123**	**1.19**	**.98**	**12.16**	**125.02**	**30.31**
Colorado	2	12,260	.52	.42	7.40	164.70	40.38
Kentucky	674	12,091	.97	.80	11.85	125.99	30.47
Maryland	2,186	12,203	1.55	1.27	15.99	115.36	28.16
Ohio	390	12,328	3.71	3.01	9.90	103.73	25.58
Pennsylvania	2,926	12,789	1.53	1.19	9.42	114.21	29.21
Virginia	18	13,941	.62	.44	4.73	120.26	33.53
West Virginia	16,969	12,114	1.08	.89	12.49	128.34	31.09
Wyoming	629	8,841	.24	.27	4.44	138.64	24.52
Wisconsin	**23,888**	**9,108**	**.37**	**.41**	**5.26**	**104.64**	**19.06**
Colorado	605	12,044	.43	.36	7.87	161.11	38.81
Illinois	495	12,001	1.46	1.21	6.34	135.39	32.50
Indiana	347	11,228	1.38	1.23	7.34	162.07	36.39
Kentucky	117	12,711	1.45	1.14	9.65	232.30	59.05
Montana	482	9,323	.33	.35	3.99	125.35	23.37
Pennsylvania	701	13,114	1.51	1.15	7.17	125.33	32.87
Utah	293	11,973	.64	.53	7.57	167.43	40.09
Virginia	25	14,065	.64	.45	5.31	153.75	43.25
West Virginia	34	13,197	.87	.66	7.43	254.43	67.16
Wyoming	20,790	8,705	.28	.32	5.03	95.82	16.68
Wyoming	**24,163**	**8,833**	**.48**	**.55**	**7.00**	**76.74**	**13.56**
Wyoming	24,163	8,833	.48	.55	7.00	76.74	13.56
Total	**762,815**	**10,019**	**.89**	**.89**	**8.82**	**123.15**	**24.68**

[1] The cost of coal shown for the States of Alabama, Florida, Kentucky, and Tennessee is not the total delivered cost of coal to these States. For more detailed information see footnotes 3, 4, and 5 at the end of Table 31.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Table 23. Origin and Destination of Coal by State, 2001

Origin Destination	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Alabama	**10,579**	**12,136**	**1.15**	**0.95**	**12.74**	**164.59**	**39.95**
Alabama	10,391	12,137	1.14	.94	12.75	163.93	39.79
Florida	3	11,810	.99	.84	14.00	185.34	43.78
Georgia	137	12,124	1.56	1.29	12.14	211.46	51.28
Mississippi	35	12,390	.75	.60	11.29	188.82	46.79
Tennessee	12	10,500	1.40	1.33	20.00	123.33	25.90
Arizona	**13,156**	**10,929**	**.51**	**.47**	**9.60**	**119.61**	**26.14**
Arizona	8,223	10,909	.53	.48	9.35	117.14	25.56
Nevada	4,933	10,963	.49	.45	10.02	123.70	27.12
Colorado	**25,112**	**11,068**	**.45**	**.41**	**8.46**	**132.35**	**29.30**
Alabama	9	12,250	.65	.53	11.00	169.55	41.54
Arizona	858	10,762	.39	.36	7.16	178.53	38.43
Colorado	10,388	10,612	.44	.42	8.06	103.58	21.98
Florida	152	11,991	.46	.38	8.54	190.93	45.79
Georgia	49	11,039	.49	.44	10.33	227.14	50.15
Illinois	11	11,691	.53	.45	7.80	175.45	41.02
Indiana	168	12,074	.45	.37	8.71	146.58	35.40
Iowa	481	11,481	.43	.37	7.61	136.65	31.38
Kansas	1,320	11,023	.47	.43	8.52	153.74	33.89
Kentucky	2,512	11,936	.41	.34	8.13	137.92	32.92
Michigan	759	12,079	.58	.48	9.67	149.42	36.10
Mississippi	2,736	11,683	.53	.46	9.38	165.72	38.72
Missouri	57	12,047	.45	.38	9.17	185.69	44.74
Tennessee	2,001	11,994	.53	.44	9.00	131.14	31.46
Texas	977	10,783	.41	.38	6.92	143.29	30.90
Utah	2,028	9,929	.40	.40	10.15	156.72	31.12
West Virginia	2	12,260	.52	.42	7.40	164.70	40.38
Wisconsin	605	12,044	.43	.36	7.87	161.11	38.81
Illinois	**25,562**	**11,421**	**2.21**	**1.94**	**8.66**	**136.63**	**31.21**
Alabama	1,359	12,170	1.88	1.54	7.46	123.69	30.11
Florida	7,479	11,881	2.16	1.81	7.90	157.06	37.32
Illinois	6,780	10,521	2.13	2.03	9.51	136.30	28.68
Indiana	4,444	11,048	2.39	2.17	9.37	116.21	25.68
Iowa	201	11,311	2.77	2.45	10.04	125.05	28.29
Kentucky	448	12,238	2.93	2.39	9.35	115.67	28.31
Minnesota	120	12,119	1.04	.86	6.47	186.94	45.31
Mississippi	401	12,071	1.42	1.18	6.42	153.48	37.05
Missouri	1,230	11,587	2.26	1.95	8.66	132.44	30.69
Ohio	44	12,359	2.43	1.96	8.34	145.25	35.90
Tennessee	2,560	12,239	2.57	2.10	8.75	119.83	29.33
Wisconsin	495	12,001	1.46	1.21	6.34	135.39	32.50
Indiana	**28,004**	**11,077**	**2.12**	**1.91**	**9.03**	**109.89**	**24.35**
Florida	867	11,338	3.17	2.80	8.79	144.26	32.71
Illinois	365	11,320	2.61	2.31	8.87	126.27	28.59
Indiana	24,783	11,055	2.02	1.83	9.01	108.14	23.91
Iowa	16	11,569	.85	.73	4.43	173.70	40.19
Kentucky	1,411	11,200	3.35	2.99	10.26	96.21	21.55
Minnesota	64	10,850	.85	.79	9.20	169.91	36.87
Ohio	109	11,011	1.53	1.39	8.84	124.41	27.40
Tennessee	43	11,683	1.18	1.01	5.00	141.30	33.02
Wisconsin	347	11,228	1.38	1.23	7.34	162.07	36.39
Kansas	**160**	**10,573**	**3.73**	**3.53**	**20.10**	**120.27**	**25.43**
Kansas	160	10,573	3.73	3.53	20.10	120.27	25.43
Kentucky	**97,180**	**12,166**	**1.48**	**1.22**	**11.02**	**147.04**	**35.78**
Alabama	3,004	11,814	2.42	2.05	12.51	131.22	31.00
Delaware	10	12,473	.65	.52	10.23	248.18	61.91
Florida	10,572	12,587	1.52	1.21	9.81	177.92	44.79
Georgia	16,151	12,409	.98	.79	10.53	168.08	41.72
Illinois	249	11,308	1.10	.97	6.47	213.64	48.32
Indiana	828	11,663	.75	.64	10.86	142.07	33.14
Iowa	10	11,477	1.43	1.25	10.40	200.00	45.91
Kentucky	19,095	11,367	2.44	2.14	13.55	106.30	24.17
Michigan	4,059	12,809	.97	.76	8.39	154.38	39.55
Mississippi	863	12,175	.96	.79	11.85	151.40	36.87

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

Table 23. Origin and Destination of Coal by State, 2001 (Continued)

Origin Destination	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Kentucky (Continued)							
Missouri	30	13,395	1.11	0.83	6.18	206.83	55.41
North Carolina	10,907	12,343	.98	.79	10.87	161.70	39.92
Ohio	5,845	11,732	.95	.81	13.37	126.40	29.66
South Carolina	12,759	12,631	1.17	.93	9.17	155.38	39.25
Tennessee	9,395	12,068	1.87	1.55	10.53	122.88	29.66
Virginia	2,613	12,751	1.18	.93	9.09	187.48	47.81
West Virginia	674	12,091	.97	.80	11.85	125.99	30.47
Wisconsin	117	12,711	1.45	1.14	9.65	232.30	59.05
Louisiana	**3,754**	**6,839**	**1.15**	**1.68**	**13.66**	**141.66**	**19.38**
Louisiana	3,754	6,839	1.15	1.68	13.66	141.66	19.38
Maryland	**2,482**	**11,970**	**1.69**	**1.41**	**17.38**	**114.43**	**27.40**
New Jersey	23	12,879	2.37	1.84	10.80	194.80	50.18
Virginia	273	10,033	2.75	2.75	29.02	96.82	19.43
West Virginia	2,186	12,203	1.55	1.27	15.99	115.36	28.16
Missouri	**247**	**10,940**	**4.67**	**4.27**	**16.58**	**131.55**	**28.78**
Kansas	167	10,983	5.61	5.11	18.32	117.06	25.71
Missouri	80	10,851	2.71	2.50	12.94	162.11	35.18
Montana	**20,821**	**9,099**	**.49**	**.54**	**6.27**	**115.75**	**21.06**
Arizona	157	9,388	.32	.34	3.91	125.24	23.51
Kansas	200	8,773	.31	.35	5.50	105.95	18.59
Michigan	9,120	9,415	.37	.39	4.52	127.89	24.08
Minnesota	10,545	8,890	.61	.68	7.84	104.56	18.59
Montana	307	6,539	.53	.82	9.51	94.93	12.42
New Hampshire	10	9,465	.34	.36	4.10	207.10	39.20
Texas	1	8,746	.66	.75	8.71	123.70	21.64
Wisconsin	482	9,323	.33	.35	3.99	125.35	23.37
New Mexico	**21,254**	**9,425**	**.68**	**.73**	**18.82**	**137.99**	**26.01**
Arizona	9,711	9,565	.65	.67	15.77	127.13	24.32
New Mexico	11,543	9,308	.72	.77	21.39	147.38	27.43
North Dakota	**23,679**	**6,537**	**.74**	**1.13**	**9.63**	**74.36**	**9.72**
North Dakota	23,679	6,537	.74	1.13	9.63	74.36	9.72
Ohio	**18,789**	**11,693**	**3.23**	**2.77**	**10.81**	**132.57**	**31.00**
Indiana	268	11,060	3.64	3.29	12.58	123.69	27.36
Kentucky	201	11,935	3.21	2.69	11.52	105.75	25.24
Michigan	158	11,870	2.84	2.40	12.17	170.96	40.58
New Hampshire	18	13,225	2.12	1.60	5.80	215.95	57.12
Ohio	17,753	11,682	3.22	2.76	10.79	133.24	31.13
West Virginia	390	12,328	3.71	3.01	9.90	103.73	25.58
Oklahoma	**21**	**12,559**	**3.01**	**2.39**	**10.48**	**120.87**	**30.36**
Kansas	17	12,586	3.08	2.45	10.32	111.44	28.05
Missouri	4	12,442	2.68	2.16	11.16	162.36	40.40
Pennsylvania	**10,469**	**12,961**	**1.79**	**1.38**	**8.16**	**125.24**	**32.47**
Alabama	5	13,355	2.38	1.78	7.60	112.20	29.97
Florida	381	12,985	1.91	1.47	7.42	152.07	39.49
Illinois	119	13,098	1.58	1.21	6.98	244.22	63.98
Indiana	362	12,677	2.30	1.81	9.57	122.36	31.03
Iowa	17	13,148	1.51	1.15	6.30	186.11	48.94
Kentucky	93	12,814	2.48	1.93	8.40	100.11	25.66
Michigan	2,074	12,999	1.59	1.22	7.21	121.27	31.53
New Hampshire	956	13,181	1.61	1.22	6.87	165.59	43.65
New Jersey	10	12,636	.49	.39	6.90	279.00	70.51
New York	354	12,900	1.80	1.40	8.58	153.74	39.67
Ohio	987	13,036	2.31	1.77	7.97	99.45	25.93
Pennsylvania	526	12,922	2.16	1.67	8.86	119.13	30.79
South Carolina	9	12,980	2.38	1.83	7.70	186.80	48.49
Tennessee	874	13,168	2.52	1.91	7.74	111.34	29.32
Virginia	76	12,830	1.40	1.09	11.10	228.62	58.66
West Virginia	2,926	12,789	1.53	1.19	9.42	114.21	29.21
Wisconsin	701	13,114	1.51	1.15	7.17	125.33	32.87

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

Table 23. Origin and Destination of Coal by State, 2001 (Continued)

Origin Destination	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Tennessee	**1,277**	**12,749**	**1.20**	**0.94**	**8.07**	**151.15**	**38.54**
North Carolina	42	12,934	1.00	.77	7.41	222.28	57.50
South Carolina	851	12,779	1.37	1.07	7.05	157.02	40.13
Tennessee	383	12,661	.85	.67	10.42	129.97	32.91
Texas	**37,032**	**6,405**	**1.13**	**1.76**	**16.62**	**128.99**	**16.52**
Texas	37,032	6,405	1.13	1.76	16.62	128.99	16.52
Utah	**18,074**	**11,863**	**.52**	**.44**	**8.85**	**115.86**	**27.49**
Indiana	273	12,100	.47	.39	8.89	164.40	39.79
Iowa	49	11,337	.42	.37	8.48	128.72	29.19
Kentucky	181	11,625	.51	.44	9.25	151.60	35.25
Michigan	25	12,605	.77	.61	7.38	209.89	52.91
Missouri	514	12,492	.44	.35	7.14	117.61	29.38
Nevada	3,095	11,673	.53	.46	8.73	129.25	30.17
Oregon	311	11,880	.54	.45	11.48	115.89	27.54
Tennessee	1,653	12,135	.61	.50	8.75	137.73	33.43
Utah	11,681	11,842	.50	.42	8.94	105.84	25.07
Wisconsin	293	11,973	.64	.53	7.57	167.43	40.09
Virginia	**19,647**	**12,750**	**.94**	**.74**	**10.58**	**150.31**	**38.33**
Alabama	148	12,461	.91	.73	9.44	126.96	31.64
Florida	38	13,052	1.34	1.03	9.73	222.31	58.03
Georgia	7,075	12,688	.96	.76	10.91	155.83	39.54
Indiana	1,065	13,837	.74	.53	5.55	159.30	44.09
Michigan	96	12,867	.82	.64	8.25	154.61	39.79
Mississippi	139	12,918	1.02	.79	10.18	152.23	39.33
North Carolina	1,505	12,533	.99	.79	10.91	167.87	42.08
Ohio	454	13,802	.72	.52	5.64	128.36	35.43
South Carolina	982	12,377	1.05	.84	11.36	173.45	42.94
Tennessee	2,700	12,639	.96	.76	10.36	123.54	31.23
Virginia	5,402	12,703	.92	.72	11.58	147.61	37.50
West Virginia	18	13,941	.62	.44	4.73	120.26	33.53
Wisconsin	25	14,065	.64	.45	5.31	153.75	43.25
West Virginia	**70,779**	**12,190**	**1.16**	**.95**	**12.58**	**141.39**	**34.47**
Alabama	912	12,065	.79	.66	13.38	168.75	40.72
Delaware	14	12,642	.69	.55	12.50	195.00	49.30
Florida	2,447	12,303	.83	.67	11.62	205.45	50.56
Georgia	3,793	12,287	.72	.58	22.66	186.68	45.88
Indiana	2,874	12,497	1.84	1.47	9.83	114.33	28.58
Kentucky	8,223	12,057	2.13	1.77	12.26	112.58	27.15
Michigan	3,622	12,467	1.09	.87	10.74	152.21	37.95
New Hampshire	163	13,331	2.09	1.57	6.97	162.33	43.28
New Jersey	181	12,897	1.53	1.19	9.46	228.55	58.95
New York	381	13,237	2.26	1.71	7.37	129.21	34.21
North Carolina	13,370	12,249	.75	.61	12.07	155.28	38.04
Ohio	14,076	12,001	1.17	.98	12.69	132.08	31.70
Pennsylvania	224	12,848	2.01	1.56	9.20	124.15	31.90
South Carolina	804	11,922	.79	.66	10.59	153.37	36.57
Tennessee	232	11,864	1.85	1.56	12.37	191.67	45.48
Virginia	2,461	12,681	.87	.69	9.87	158.34	40.16
West Virginia	16,969	12,114	1.08	.89	12.49	128.34	31.09
Wisconsin	34	13,197	.87	.66	7.43	254.43	67.16
Wyoming	**304,502**	**8,689**	**.32**	**.36**	**5.29**	**100.49**	**17.46**
Alabama	10,784	8,799	.26	.29	4.84	110.46	19.44
Arizona	348	8,781	.50	.57	5.50	126.81	22.27
Arkansas	14,582	8,708	.28	.32	4.61	87.46	15.23
Colorado	8,285	8,615	.31	.36	4.88	74.60	12.85
Florida	679	8,729	.25	.28	4.70	144.40	25.21
Georgia	6,579	8,783	.29	.33	5.18	157.46	27.66
Illinois	8,758	8,816	.24	.27	4.83	96.90	17.09
Indiana	16,564	8,848	.28	.31	4.85	112.82	19.96
Iowa	21,197	8,556	.34	.40	5.28	78.70	13.47
Kansas	19,421	8,487	.35	.41	5.09	100.12	16.99
Kentucky	1,680	8,739	.30	.34	5.86	108.03	18.88
Louisiana	4,359	8,786	.39	.44	5.24	123.66	21.73
Michigan	13,552	8,814	.26	.30	5.11	104.67	18.45

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

Table 23. Origin and Destination of Coal by State, 2001 (Continued)

Origin Destination	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short Ton)
Wyoming (Continued)							
Minnesota	7,330	8,866	0.26	0.29	4.80	95.14	16.87
Mississippi	54	8,768	.29	.33	5.70	146.20	25.64
Missouri	37,123	8,767	.29	.33	5.00	93.21	16.34
Nebraska	12,949	8,586	.31	.36	5.07	56.57	9.71
Nevada	27	9,714	.48	.49	8.24	217.21	42.20
North Dakota	544	8,026	.43	.54	5.41	66.72	10.71
Ohio	496	8,779	.27	.31	4.80	147.62	25.92
Oklahoma	17,118	8,695	.30	.34	5.11	90.57	15.75
Oregon	2,272	8,272	.35	.43	5.49	110.03	18.20
South Dakota	2,182	8,427	.33	.39	5.49	103.27	17.41
Tennessee	4,385	8,814	.28	.32	5.05	102.79	18.12
Texas	47,650	8,555	.32	.38	5.71	135.45	23.17
West Virginia	629	8,841	.24	.27	4.44	138.64	24.52
Wisconsin	20,790	8,705	.28	.32	5.03	95.82	16.68
Wyoming	24,163	8,833	.48	.55	7.00	76.74	13.56
Imported	**10,233**	**11,855**	**.66**	**.56**	**6.71**	**165.22**	**39.17**
Alabama	3,254	11,674	.69	.59	5.48	151.03	35.26
Florida	3,574	12,040	.65	.54	7.26	170.81	41.13
Georgia	578	12,311	.75	.61	7.31	158.13	38.93
Indiana	210	11,456	.52	.45	11.43	211.08	48.36
Mississippi	1,895	11,470	.65	.56	7.14	168.97	38.76
New Hampshire	564	12,694	.65	.51	6.53	169.46	43.02
New York	37	13,309	.61	.46	7.27	156.10	41.55
North Carolina	120	11,480	.77	.67	6.59	259.82	59.66
Total	**762,815**	**10,019**	**.89**	**.89**	**8.82**	**123.15**	**24.68**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Alabama Electric Coop Inc Lowman	**1,497**	**11,776**	**1.25**	**1.06**	**9.26**	**138.92**	**32.72**
Alabama	598	11,980	1.62	1.35	12.17	134.37	32.19
Fayette	556	12,006	1.56	1.30	11.93	134.50	32.30
Jefferson	33	11,874	2.38	2.00	14.72	131.67	31.27
Marion	9	10,760	1.99	1.85	17.80	136.30	29.33
Kentucky	309	11,974	1.72	1.44	10.84	138.37	33.14
Union	309	11,974	1.72	1.44	10.84	138.37	33.14
Imported	589	11,466	.63	.55	5.46	144.05	33.03
Imported Coal	589	11,466	.63	.55	5.46	144.05	33.03
Alabama Power Co Barry	**3,928**	**11,879**	**.74**	**.62**	**7.80**	**173.46**	**41.21**
Alabama	1,228	12,216	.79	.64	12.85	218.71	53.43
Jefferson	1,228	12,216	.79	.64	12.85	218.71	53.43
Illinois	35	12,179	1.54	1.26	6.92	112.30	27.35
Saline	35	12,179	1.54	1.26	6.92	112.30	27.35
Imported	2,664	11,720	.70	.60	5.49	152.54	35.75
Imported Coal	2,664	11,720	.70	.60	5.49	152.54	35.75
Alabama Power Co Gadsden	**255**	**12,168**	**1.59**	**1.31**	**13.73**	**158.19**	**38.50**
Alabama	255	12,168	1.59	1.31	13.73	158.19	38.50
Walker	255	12,168	1.59	1.31	13.73	158.19	38.50
Alabama Power Co Gaston	**5,219**	**12,175**	**1.23**	**1.01**	**12.50**	**139.37**	**33.94**
Alabama	5,202	12,173	1.23	1.01	12.51	139.24	33.90
Fayette	936	12,077	1.55	1.28	12.36	135.89	32.82
Jefferson	119	13,519	.47	.35	8.33	116.37	31.46
Shelby	81	12,300	.71	.58	12.15	128.78	31.68
Tuscaloosa	1,000	12,361	.79	.64	12.87	142.22	35.16
Walker	3,065	12,085	1.32	1.10	12.61	140.54	33.97
Kentucky	9	12,514	1.14	.91	10.97	173.80	43.50
Pike	9	12,514	1.14	.91	10.97	173.80	43.50
Virginia	8	13,418	.93	.69	8.49	181.20	48.63
Dickenson	8	13,418	.93	.69	8.49	181.20	48.63
Alabama Power Co Gorgas	**2,675**	**12,171**	**.90**	**.74**	**13.09**	**197.59**	**48.10**
Alabama	2,675	12,171	.90	.74	13.09	197.59	48.10
Jefferson	2,139	12,250	.78	.63	12.70	213.84	52.39
Walker	536	11,855	1.39	1.17	14.65	130.58	30.96
Alabama Power Co Greene	**1,350**	**11,978**	**1.51**	**1.26**	**8.75**	**126.49**	**30.30**
Alabama	433	11,470	1.67	1.46	13.44	138.72	31.82
Walker	433	11,470	1.67	1.46	13.44	138.72	31.82
Illinois	917	12,217	1.44	1.17	6.54	121.07	29.58
Christian	92	12,198	1.55	1.27	6.62	124.90	30.47
Saline	825	12,219	1.42	1.16	6.53	120.64	29.48
Alabama Power Co James Miller	**10,784**	**8,799**	**.26**	**.29**	**4.84**	**110.46**	**19.44**
Wyoming	10,784	8,799	.26	.29	4.84	110.46	19.44
Campbell	10,157	8,798	.26	.29	4.81	111.17	19.56
Converse	627	8,815	.26	.30	5.36	98.97	17.45
Ameren - CIPS Hutsonville	**320**	**11,355**	**2.90**	**2.55**	**9.02**	**112.84**	**25.63**
Illinois	1	11,250	3.04	2.70	9.80	106.40	23.94
Jackson	1	11,250	3.04	2.70	9.80	106.40	23.94
Indiana	319	11,355	2.90	2.55	9.02	112.86	25.63
Daviess	264	11,388	2.90	2.55	9.00	111.87	25.48
Gibson	13	11,300	2.97	2.63	9.50	129.20	29.20
Greene	42	11,167	2.85	2.55	9.00	114.08	25.48
Ameren - CIPS Coffeen	**2,015**	**10,282**	**1.14**	**1.11**	**8.04**	**126.99**	**26.11**
Illinois	1,975	10,311	1.16	1.12	8.11	127.24	26.24
Logan	148	10,450	3.10	2.97	9.50	152.39	31.85
Macoupin	1,827	10,300	1.00	.97	8.00	125.18	25.79
Wyoming	40	8,820	.23	.26	4.50	112.70	19.88
Campbell	40	8,820	.23	.26	4.50	112.70	19.88
Ameren - CIPS Newton	**3,605**	**8,784**	**.25**	**.29**	**4.95**	**111.00**	**19.50**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Ameren - CIPS Newton							
Wyoming	3,605	8,784	0.25	0.29	4.95	111.00	19.50
Campbell	1,096	8,803	.27	.31	5.17	113.97	20.07
Converse	2,509	8,775	.24	.27	4.85	109.69	19.25
Ameren - CIPS Meredosia	**674**	**10,591**	**1.81**	**1.71**	**8.76**	**138.38**	**29.31**
Illinois	674	10,591	1.81	1.71	8.76	138.38	29.31
Jackson	105	11,200	2.80	2.50	11.00	128.16	28.71
Logan	117	10,791	3.07	2.84	9.61	134.82	29.10
Macoupin	452	10,398	1.26	1.21	8.03	141.89	29.51
Ameren - UE Labadie	**9,284**	**8,729**	**.30**	**.34**	**5.23**	**96.81**	**16.90**
Wyoming	9,284	8,729	.30	.34	5.23	96.81	16.90
Campbell	6,155	8,693	.33	.38	5.20	98.52	17.13
Converse	3,129	8,800	.23	.26	5.28	93.50	16.46
Ameren - UE Meramec	**1,984**	**9,649**	**.90**	**.93**	**6.51**	**111.12**	**21.44**
Illinois	654	11,375	2.27	2.00	9.67	131.18	29.84
Jackson	425	11,200	2.80	2.50	11.00	130.82	29.30
Saline	229	11,700	1.29	1.10	7.20	131.82	30.85
Wyoming	1,330	8,800	.23	.26	4.95	98.37	17.31
Campbell	799	8,800	.23	.26	4.72	101.54	17.87
Converse	531	8,800	.22	.25	5.30	93.60	16.47
Ameren - UE Rush Island	**4,529**	**8,373**	**.53**	**.64**	**5.52**	**94.55**	**15.83**
Wyoming	4,529	8,373	.53	.64	5.52	94.55	15.83
Campbell	4,403	8,364	.54	.65	5.53	94.69	15.84
Converse	126	8,717	.22	.25	5.30	89.57	15.62
Ameren - UE Sioux	**3,000**	**9,157**	**.50**	**.54**	**5.57**	**97.74**	**17.90**
Illinois	351	11,848	2.43	2.05	7.69	125.22	29.67
Jefferson	113	11,950	1.35	1.13	6.40	130.60	31.21
White	238	11,800	2.94	2.49	8.30	122.64	28.94
Wyoming	2,649	8,800	.24	.27	5.29	92.83	16.34
Campbell	171	8,800	.30	.34	5.15	97.43	17.15
Converse	2,478	8,800	.23	.27	5.30	92.51	16.28
American Mun Power Ohio Inc Richard Gorsuch	**758**	**11,804**	**1.93**	**1.63**	**14.53**	**120.42**	**28.43**
Ohio	758	11,804	1.93	1.63	14.53	120.42	28.43
Noble	758	11,804	1.93	1.63	14.53	120.42	28.43
Ames City of Ames	**228**	**8,863**	**.20**	**.22**	**4.34**	**144.34**	**25.59**
Wyoming	228	8,863	.20	.22	4.34	144.34	25.59
Campbell	228	8,863	.20	.22	4.34	144.34	25.59
Appalachian Power Co Amos	**5,549**	**12,022**	**.77**	**.64**	**11.93**	**124.93**	**30.04**
West Virginia	5,549	12,022	.77	.64	11.93	124.93	30.04
Boone	4,778	12,006	.77	.64	11.78	126.26	30.32
Clay	73	12,417	.69	.55	11.33	135.29	33.60
Fayette	6	12,379	.70	.57	11.70	142.20	35.21
Kanawha	490	11,962	.79	.66	13.73	110.40	26.41
Logan	39	12,139	.75	.62	12.14	111.21	27.00
Nicholas	152	12,455	.68	.55	11.13	128.34	31.97
Raleigh	3	12,635	.78	.62	12.00	98.70	24.94
Unknown[1]	8	12,556	.70	.56	11.50	116.60	29.28
Appalachian Power Co Clinch River	**1,841**	**12,348**	**.69**	**.56**	**14.46**	**139.93**	**34.56**
Kentucky	30	12,744	.71	.56	8.64	204.96	52.24
Bell	20	12,949	.67	.52	7.44	202.86	52.53
Pike	10	12,340	.80	.65	11.00	209.30	51.66
Virginia	1,742	12,339	.69	.56	14.72	136.43	33.67
Dickenson	37	13,362	.80	.60	9.63	110.33	29.48
Russell	1,642	12,294	.68	.55	15.02	135.98	33.44
Wise	63	12,907	.86	.67	9.95	163.66	42.25

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Appalachian Power Co Clinch River							
West Virginia	70	12,410	0.76	0.61	10.30	198.57	49.29
Mingo	11	12,076	.66	.55	12.56	96.00	23.19
Wyoming	59	12,473	.78	.63	9.87	217.21	54.18
Appalachian Power Co Glen Lyn	**619**	**12,793**	**.86**	**.67**	**10.37**	**147.28**	**37.68**
Virginia	536	12,779	.88	.69	10.34	142.05	36.30
Buchanan	61	12,641	.82	.65	11.02	146.10	36.94
Wise	474	12,796	.88	.69	10.25	141.53	36.22
West Virginia	84	12,883	.78	.61	10.51	180.51	46.51
Mcdowell	84	12,883	.78	.61	10.51	180.51	46.51
Appalachian Power Co Kanawha River	**1,138**	**12,100**	**.77**	**.63**	**12.70**	**105.57**	**25.55**
Kentucky	158	12,077	.81	.67	12.68	92.30	22.29
Lawrence	158	12,077	.81	.67	12.68	92.30	22.29
West Virginia	980	12,104	.76	.63	12.70	107.71	26.07
Boone	288	12,452	.72	.58	10.70	106.45	26.51
Clay	88	12,340	.70	.57	12.33	138.39	34.15
Fayette	120	11,937	.78	.65	13.51	108.25	25.84
Kanawha	484	11,894	.78	.66	13.76	102.60	24.41
Appalachian Power Co Mountaineer	**2,711**	**11,442**	**.58**	**.51**	**10.48**	**138.50**	**31.69**
Colorado	2	12,260	.52	.42	7.40	164.70	40.38
Gunnison	2	12,260	.52	.42	7.40	164.70	40.38
Kentucky	73	12,106	.66	.55	11.21	133.82	32.40
Knott	8	12,228	.70	.57	11.36	212.40	51.95
Magoffin	8	12,228	.70	.57	11.36	212.40	51.95
Martin	27	11,748	.63	.54	11.28	112.03	26.32
Pike	31	12,355	.67	.54	11.08	113.28	27.99
West Virginia	2,013	12,221	.69	.56	12.33	138.62	33.88
Boone	97	12,078	.68	.56	12.87	127.74	30.86
Clay	838	12,353	.70	.56	12.22	146.78	36.26
Fayette	152	12,334	.70	.57	12.31	147.40	36.36
Kanawha	405	12,001	.70	.58	13.68	127.75	30.66
Logan	28	12,123	.67	.56	11.93	123.56	29.96
Mingo	228	11,805	.65	.55	11.55	125.46	29.62
Nicholas	248	12,548	.67	.54	11.01	140.29	35.21
Wayne	14	11,459	.65	.57	13.80	143.90	32.98
Unknown[1]	4	12,798	.66	.52	10.30	126.90	32.48
Wyoming	622	8,840	.24	.27	4.44	138.59	24.50
Campbell	622	8,840	.24	.27	4.44	138.59	24.50
Arizona Electric Pwr Coop Inc Apache	**1,404**	**9,629**	**.70**	**.73**	**14.13**	**143.92**	**27.72**
Colorado	409	10,458	.33	.32	5.71	179.00	37.44
Moffat	409	10,458	.33	.32	5.71	179.00	37.44
New Mexico	982	9,296	.86	.92	17.76	127.19	23.65
Colfax	53	10,058	.49	.48	17.79	148.65	29.90
Mckinley	929	9,252	.88	.95	17.76	125.85	23.29
Wyoming	13	8,786	.30	.34	4.84	170.20	29.91
Campbell	13	8,786	.30	.34	4.84	170.20	29.91
Arizona Public Service Co Cholla	**2,534**	**9,762**	**.49**	**.50**	**13.58**	**117.01**	**22.85**
Colorado	182	10,676	.35	.33	6.33	181.24	38.70
La Plata	70	11,343	.40	.35	7.76	178.33	40.46
Moffat	112	10,260	.32	.31	5.44	183.24	37.60
Montana	36	9,387	.33	.35	4.00	127.07	23.86
Big Horn	36	9,387	.33	.35	4.00	127.07	23.86
New Mexico	2,316	9,696	.50	.52	14.30	111.30	21.58
Mckinley	2,316	9,696	.50	.52	14.30	111.30	21.58
Arizona Public Service Co Four Corners	**4,892**	**9,030**	**.72**	**.80**	**20.34**	**99.44**	**17.96**
New Mexico	4,892	9,030	.72	.80	20.34	99.44	17.96
San Juan	4,892	9,030	.72	.80	20.34	99.44	17.96
Arkansas Power & Light Co Independence	**6,573**	**8,972**	**.20**	**.22**	**4.21**	**69.30**	**12.43**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Arkansas Power & Light Co Independence							
Wyoming	6,573	8,972	0.20	0.22	4.21	69.30	12.43
Campbell	6,573	8,972	.20	.22	4.21	69.30	12.43
Arkansas Power & Light Co Whitebluff	**6,109**	**8,500**	**.35**	**.41**	**4.98**	**89.04**	**15.14**
Wyoming	6,109	8,500	.35	.41	4.98	89.04	15.14
Campbell	6,109	8,500	.35	.41	4.98	89.04	15.14
Associated Electric Coop Inc Hill	**5,126**	**8,908**	**.20**	**.22**	**4.26**	**80.00**	**14.25**
Wyoming	5,126	8,908	.20	.22	4.26	80.00	14.25
Campbell	5,126	8,908	.20	.22	4.26	80.00	14.25
Associated Electric Coop Inc Madrid	**4,428**	**8,913**	**.20**	**.22**	**4.26**	**100.22**	**17.86**
Wyoming	4,428	8,913	.20	.22	4.26	100.22	17.86
Campbell	4,428	8,913	.20	.22	4.26	100.22	17.86
Atlantic City Electric Co Deepwater	**68**	**12,409**	**.75**	**.60**	**11.37**	**265.14**	**65.80**
West Virginia	68	12,409	.75	.60	11.37	265.14	65.80
Logan	68	12,409	.75	.60	11.37	265.14	65.80
Atlantic City Electric Co England	**119**	**13,117**	**2.19**	**1.67**	**8.38**	**215.86**	**56.63**
Maryland	23	12,879	2.37	1.84	10.80	194.80	50.18
Garrett	23	12,879	2.37	1.84	10.80	194.80	50.18
Pennsylvania	10	12,636	.49	.39	6.90	279.00	70.51
Washington	10	12,636	.49	.39	6.90	279.00	70.51
West Virginia	86	13,238	2.35	1.77	7.93	214.03	56.66
Monongalia	63	13,351	2.38	1.78	7.00	205.98	55.00
Upshur	23	12,924	2.26	1.75	10.50	237.10	61.29
Basin Electric Power Coop Laramie River	**7,740**	**8,376**	**.31**	**.37**	**5.18**	**46.73**	**7.83**
Wyoming	7,740	8,376	.31	.37	5.18	46.73	7.83
Campbell	7,740	8,376	.31	.37	5.18	46.73	7.83
Basin Electric Power Coop Antelope Valley	**4,887**	**6,592**	**.66**	**1.00**	**9.38**	**70.28**	**9.26**
North Dakota	4,887	6,592	.66	1.00	9.38	70.28	9.26
Mercer	4,887	6,592	.66	1.00	9.38	70.28	9.26
Basin Electric Power Coop Leland Olds	**3,648**	**6,841**	**.69**	**1.01**	**8.24**	**76.33**	**10.44**
North Dakota	3,103	6,632	.73	1.11	8.73	78.37	10.40
Mercer	3,103	6,632	.73	1.11	8.73	78.37	10.40
Wyoming	544	8,026	.43	.54	5.41	66.72	10.71
Campbell	544	8,026	.43	.54	5.41	66.72	10.71
Big Rivers Electric Corp Reid-Henderson II	**265**	**11,858**	**3.23**	**2.73**	**11.19**	**90.30**	**21.42**
Kentucky	265	11,858	3.23	2.73	11.19	90.30	21.42
Webster	265	11,858	3.23	2.73	11.19	90.30	21.42
Black Hills Corp Neal Simpson II	**538**	**8,091**	**.62**	**.76**	**7.05**	**46.84**	**7.58**
Wyoming	538	8,091	.62	.76	7.05	46.84	7.58
Campbell	538	8,091	.62	.76	7.05	46.84	7.58
Cardinal Operating Co Cardinal	**4,303**	**11,973**	**1.32**	**1.10**	**11.56**	**141.74**	**33.94**
Kentucky	480	12,551	.77	.61	10.14	148.59	37.30
Clinton	21	12,682	.68	.54	9.19	147.49	37.41
Floyd	53	12,049	.81	.67	12.25	143.80	34.65
Knott	183	12,712	.70	.55	9.59	142.73	36.29
Magoffin	165	12,704	.70	.55	9.68	142.14	36.12
Martin	3	12,049	.81	.67	12.25	143.80	34.65
Pike	55	12,023	1.18	.98	11.54	194.70	46.82
Ohio	685	11,734	2.85	2.43	12.62	101.83	23.90
Belmont	311	11,647	3.15	2.71	13.26	108.08	25.18
Jefferson	330	11,800	2.50	2.12	12.00	95.30	22.49
Pike	43	11,860	3.29	2.77	12.80	107.40	25.48
Pennsylvania	353	13,019	2.43	1.87	8.19	94.98	24.73
Greene	348	13,029	2.44	1.87	8.13	94.24	24.56
Washington	5	12,357	1.91	1.55	12.30	147.80	36.53

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Cardinal Operating Co Cardinal							
West Virginia	2,499	12,132	0.98	0.81	12.83	156.36	37.94
Boone	396	12,004	.87	.73	12.21	141.31	33.93
Brooke	89	12,265	3.71	3.02	10.24	212.88	52.22
Kanawha	1,043	12,145	.81	.66	13.51	172.74	41.96
Logan	528	12,033	.75	.62	12.89	151.94	36.57
Marshall	62	12,354	2.64	2.13	9.49	92.80	22.93
Mingo	21	11,923	.86	.72	11.13	121.65	29.01
Monongalia	12	11,668	1.63	1.40	13.79	100.75	23.51
Wayne	25	11,960	.88	.74	11.49	155.29	37.15
Webster	322	12,376	.96	.78	12.80	130.53	32.31
Unknown[1]	1	12,117	1.78	1.47	13.20	105.10	25.47
Wyoming	286	8,885	.23	.26	4.44	161.78	28.75
Campbell	286	8,885	.23	.26	4.44	161.78	28.75
Carolina Power & Light Co Asheville	**712**	**12,733**	**.92**	**.72**	**10.18**	**171.26**	**43.61**
Kentucky	160	12,554	1.13	.90	11.66	158.63	39.83
Bell	37	13,044	1.78	1.37	8.29	174.29	45.47
Pike	123	12,406	.93	.75	12.67	153.66	38.13
Tennessee	42	12,934	1.00	.77	7.41	222.28	57.50
Campbell	42	12,934	1.00	.77	7.41	222.28	57.50
Virginia	93	12,880	1.01	.79	10.45	170.55	43.93
Wise	84	12,893	1.03	.80	10.53	171.89	44.33
Unknown[1]	9	12,748	.84	.66	9.70	157.70	40.21
West Virginia	416	12,748	.81	.64	9.83	170.93	43.58
Boone	416	12,748	.81	.64	9.83	170.93	43.58
Carolina Power & Light Co Cape Fear	**487**	**12,447**	**.93**	**.74**	**10.66**	**154.45**	**38.45**
Kentucky	163	12,428	1.05	.84	11.49	167.38	41.60
Floyd	18	12,621	1.07	.85	9.70	175.32	44.25
Johnson	27	11,861	1.11	.93	11.70	146.33	34.71
Pike	118	12,529	1.03	.82	11.71	170.75	42.79
Virginia	36	12,595	1.12	.89	11.99	170.12	42.85
Wise	36	12,595	1.12	.89	11.99	170.12	42.85
West Virginia	287	12,439	.83	.67	10.02	145.10	36.10
Mingo	29	12,315	.72	.59	9.82	161.30	39.73
Nicholas	67	12,448	.90	.72	12.16	145.41	36.20
Wayne	191	12,455	.83	.66	9.30	142.54	35.51
Carolina Power & Light Co Lee	**702**	**12,446**	**.90**	**.72**	**10.68**	**157.85**	**39.29**
Kentucky	360	12,430	.96	.77	11.99	169.06	42.03
Floyd	9	12,962	.98	.76	7.30	177.30	45.96
Johnson	1	12,068	1.26	1.04	11.00	145.90	35.21
Pike	351	12,417	.96	.77	12.11	168.88	41.94
Virginia	8	13,049	1.09	.84	9.20	187.00	48.80
Wise	8	13,049	1.09	.84	9.20	187.00	48.80
West Virginia	334	12,449	.83	.67	9.30	145.08	36.12
Mingo	1	12,620	.78	.62	9.00	162.80	41.09
Wayne	333	12,448	.83	.67	9.30	145.05	36.11
Carolina Power & Light Co Mayo	**1,317**	**12,166**	**.64**	**.53**	**11.96**	**165.12**	**40.18**
Kentucky	238	12,299	.65	.53	10.73	174.00	42.80
Martin	10	11,821	.70	.59	12.00	170.90	40.40
Pike	227	12,321	.65	.53	10.67	174.14	42.91
West Virginia	1,080	12,137	.64	.52	12.23	163.13	39.60
Mingo	837	12,029	.63	.53	12.35	163.70	39.38
Nicholas	243	12,508	.64	.51	11.82	161.25	40.34
Carolina Power & Light Co Robinson	**262**	**12,677**	**1.19**	**.94**	**9.38**	**171.76**	**43.55**
Kentucky	223	12,722	1.18	.93	9.06	167.88	42.72
Floyd	111	12,755	1.30	1.02	8.90	166.98	42.60
Knott	62	12,727	1.09	.86	9.13	161.82	41.19
Letcher	31	12,746	1.09	.86	8.47	161.61	41.20
Pike	18	12,473	.91	.73	10.85	205.09	51.16

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Carolina Power & Light Co Robinson							
Pennsylvania	9	12,980	2.38	1.83	7.70	186.80	48.49
Greene	9	12,980	2.38	1.83	7.70	186.80	48.49
West Virginia	31	12,260	.96	.78	12.14	196.49	48.18
Boone	20	11,667	.96	.82	15.29	205.55	47.96
Logan	10	13,434	.96	.71	5.90	180.90	48.60
Carolina Power & Light Co Roxboro	**4,923**	**12,366**	**.82**	**.66**	**11.23**	**163.01**	**40.32**
Kentucky	2,000	12,323	.89	.72	11.46	160.66	39.60
Bell	41	12,671	.89	.70	9.34	162.96	41.30
Johnson	158	11,436	1.03	.90	12.86	146.28	33.46
Martin	196	12,120	.91	.75	10.60	180.00	43.63
Pike	1,604	12,426	.88	.71	11.48	159.60	39.66
Virginia	158	12,862	1.14	.89	10.23	158.22	40.70
Buchanan	11	12,340	.99	.80	11.70	179.10	44.20
Dickenson	11	13,637	.71	.52	5.00	180.20	49.15
Lee	10	12,981	.77	.59	8.40	151.40	39.31
Wise	127	12,831	1.22	.95	10.69	155.15	39.81
West Virginia	2,764	12,369	.74	.60	11.12	164.99	40.82
Boone	744	12,752	.81	.63	9.79	170.79	43.56
Mingo	1,256	12,082	.68	.56	11.99	169.38	40.93
Nicholas	541	12,475	.78	.62	11.70	157.80	39.37
Wayne	223	12,454	.82	.66	9.28	138.77	34.56
Carolina Power & Light Co Sutton	**702**	**12,527**	**1.01**	**.81**	**9.53**	**172.95**	**43.33**
Kentucky	529	12,566	1.06	.84	9.08	164.09	41.24
Floyd	103	12,613	1.16	.92	9.30	170.66	43.05
Knott	278	12,629	1.06	.84	9.34	157.81	39.86
Letcher	105	12,846	1.10	.85	8.50	157.22	40.39
Perry	4	12,301	.79	.64	10.30	167.70	41.26
Pike	39	11,268	.73	.65	8.08	215.40	48.54
Virginia	*	12,831	.77	.60	10.40	207.20	53.17
Dickenson	*	12,831	.77	.60	10.40	207.20	53.17
West Virginia	164	12,478	.89	.72	11.19	198.00	49.41
Boone	95	12,470	.80	.65	10.79	175.03	43.65
Logan	24	13,028	1.00	.77	7.99	192.82	50.24
Webster	45	12,202	1.02	.84	13.71	250.30	61.09
Imported	8	11,034	.50	.45	5.30	254.80	56.23
Imported Coal	8	11,034	.50	.45	5.30	254.80	56.23
Carolina Power & Light Co Weatherspoon	**277**	**12,725**	**1.10**	**.86**	**8.83**	**177.25**	**45.11**
Kentucky	260	12,740	1.12	.88	8.72	177.00	45.10
Floyd	97	12,705	1.15	.91	8.90	177.43	45.09
Knott	35	12,829	1.19	.93	8.26	175.83	45.11
Letcher	119	12,777	1.08	.85	8.53	173.70	44.39
Pike	9	12,307	1.00	.81	11.10	220.40	54.25
West Virginia	17	12,500	.79	.63	10.48	181.05	45.26
Boone	17	12,500	.79	.63	10.48	181.05	45.26
Cedar Falls City of Streeter	**38**	**12,334**	**1.41**	**1.14**	**7.47**	**194.72**	**48.03**
Illinois	11	11,890	1.25	1.05	6.65	204.16	48.55
Jackson	3	11,520	1.56	1.35	7.10	200.00	46.08
Saline	8	12,023	1.14	.95	6.49	205.60	49.44
Kentucky	10	11,477	1.43	1.25	10.40	200.00	45.91
Union	10	11,477	1.43	1.25	10.40	200.00	45.91
Pennsylvania	17	13,148	1.51	1.15	6.30	186.11	48.94
Washington	17	13,148	1.51	1.15	6.30	186.11	48.94
Central Electric Pwr Coop-MO Chamois	**308**	**9,530**	**.77**	**.81**	**5.31**	**116.75**	**22.25**
Illinois	81	11,261	2.37	2.10	8.27	137.33	30.93
Jackson	37	11,587	2.03	1.75	7.88	133.67	30.98
Macoupin	9	10,570	3.05	2.89	8.48	140.67	29.74
Randolph	35	11,080	2.57	2.32	8.65	140.68	31.17
Wyoming	227	8,916	.20	.23	4.26	107.53	19.18
Campbell	227	8,916	.20	.23	4.26	107.53	19.18
Central Hudson Gas & Elec Corp Danskammer	**37**	**13,309**	**.61**	**.46**	**7.27**	**156.10**	**41.55**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Central Hudson Gas & Elec Corp Danskammer							
Imported	37	13,309	0.61	0.46	7.27	156.10	41.55
Imported Coal	37	13,309	.61	.46	7.27	156.10	41.55
Central Illinois Light Co Duck Creek	**973**	**10,632**	**3.44**	**3.24**	**8.04**	**222.36**	**47.28**
Illinois	973	10,632	3.44	3.24	8.04	222.36	47.28
Logan	31	10,399	1.19	1.14	8.34	163.56	34.02
Macoupin	942	10,640	3.52	3.31	8.03	224.22	47.71
Central Illinois Light Co Edwards	**1,399**	**11,396**	**1.33**	**1.16**	**7.44**	**162.32**	**37.00**
Colorado	11	11,691	.53	.45	7.80	175.45	41.02
Delta	11	11,691	.53	.45	7.80	175.45	41.02
Illinois	976	11,223	1.40	1.24	7.72	134.60	30.21
Jefferson	285	12,102	1.49	1.23	6.54	133.40	32.29
Logan	120	11,499	2.63	2.29	8.49	164.23	37.77
Macoupin	471	10,644	1.00	.94	7.70	119.53	25.44
Wabash	100	11,111	1.52	1.37	10.21	169.56	37.68
Indiana	46	11,072	.59	.53	7.84	222.30	49.23
Fountain	46	11,072	.59	.53	7.84	222.30	49.23
Kentucky	249	11,308	1.10	.97	6.47	213.64	48.32
Bell	10	12,208	.75	.61	11.15	286.26	69.89
Carter	45	10,970	.90	.82	8.30	222.88	48.90
Daviess	9	12,919	1.63	1.26	8.37	228.99	59.17
Laurel	184	11,263	1.14	1.01	5.66	206.24	46.46
Pennsylvania	119	13,098	1.58	1.21	6.98	244.22	63.98
Greene	119	13,098	1.58	1.21	6.98	244.22	63.98
Central Iowa Power Coop Fair	**180**	**11,243**	**2.94**	**2.62**	**10.49**	**116.87**	**26.28**
Illinois	180	11,243	2.94	2.62	10.49	116.87	26.28
Jackson	120	11,287	2.92	2.59	10.77	118.02	26.64
Perry	60	11,157	2.99	2.68	9.96	114.58	25.57
Central Louisiana Elec Co Inc Dolet Hills	**3,754**	**6,839**	**1.15**	**1.68**	**13.66**	**141.66**	**19.38**
Louisiana	3,754	6,839	1.15	1.68	13.66	141.66	19.38
De Soto	3,754	6,839	1.15	1.68	13.66	141.66	19.38
Central Louisiana Elec Co Inc Rodemacher	**1,848**	**8,788**	**.41**	**.46**	**5.28**	**137.21**	**24.12**
Wyoming	1,848	8,788	.41	.46	5.28	137.21	24.12
Campbell	1,848	8,788	.41	.46	5.28	137.21	24.12
Central Operating Co Sporn	**2,476**	**12,066**	**.94**	**.78**	**12.31**	**128.57**	**31.03**
Kentucky	389	12,038	1.05	.87	11.87	137.44	33.09
Lawrence	165	11,972	.88	.73	12.28	96.26	23.05
Morgan	2	12,205	.85	.70	11.50	179.90	43.91
Pike	222	12,086	1.17	.97	11.56	167.38	40.46
Ohio	39	12,053	.79	.65	11.49	205.94	49.64
Mahoning	39	12,053	.79	.65	11.49	205.94	49.64
West Virginia	2,049	12,072	.92	.76	12.41	125.44	30.29
Boone	871	12,176	.86	.71	11.84	132.54	32.28
Clay	42	12,365	1.00	.81	12.07	160.99	39.81
Fayette	13	12,145	.94	.77	12.79	149.36	36.28
Kanawha	475	12,034	.78	.64	13.26	115.01	27.68
Logan	28	11,763	.98	.83	12.60	95.30	22.42
Mingo	133	11,907	.81	.68	11.95	117.67	28.02
Monongalia	213	11,878	1.53	1.29	13.84	103.48	24.58
Nicholas	16	12,638	.72	.57	11.12	148.68	37.58
Taylor	13	12,009	1.42	1.18	13.73	98.99	23.77
Wayne	180	11,983	.87	.73	11.73	133.43	31.98
Wyoming	49	11,951	.87	.73	11.51	168.58	40.29
Unknown[1]	15	12,056	1.43	1.19	13.80	107.27	25.87
Central Power & Light Co Coleto Creek	**1,695**	**9,905**	**.33**	**.34**	**5.94**	**138.82**	**27.50**
Colorado	977	10,783	.41	.38	6.92	143.29	30.90
Gunnison	183	12,142	.67	.55	11.48	149.48	36.30
Moffat	794	10,469	.35	.33	5.87	141.63	29.65

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Central Power & Light Co Coleto Creek							
Wyoming	718	8,709	0.23	0.26	4.60	131.29	22.87
Campbell	718	8,709	.23	.26	4.60	131.29	22.87
Cincinnati Gas & Electric Co East Bend	**1,724**	**12,074**	**2.47**	**2.04**	**10.76**	**111.63**	**26.96**
Illinois	116	11,955	2.80	2.34	8.08	117.05	27.99
Gallatin	32	12,518	2.77	2.21	8.83	133.07	33.32
White	83	11,735	2.81	2.39	7.79	110.39	25.91
Indiana	57	11,293	1.92	1.70	8.61	121.90	27.53
Clay	10	11,418	2.75	2.41	8.26	110.76	25.29
Gibson	12	11,024	1.65	1.50	10.20	96.10	21.19
Knox	4	11,134	1.90	1.71	9.00	170.90	38.06
Pike	10	11,701	1.39	1.19	5.50	107.60	25.18
Sullivan	21	11,223	1.92	1.71	9.24	140.96	31.64
Kentucky	399	11,670	1.65	1.41	12.59	133.04	31.05
Breathitt	23	11,944	1.88	1.57	12.66	143.36	34.25
Floyd	2	11,888	1.18	.99	13.00	118.40	28.15
Henderson	2	11,700	2.98	2.55	8.30	102.90	24.08
Johnson	3	12,933	.75	.58	7.89	124.58	32.22
Mccreary	5	11,210	3.28	2.93	9.10	143.60	32.20
Martin	6	12,155	.94	.78	8.47	148.82	36.18
Ohio	9	11,653	2.55	2.19	8.20	135.00	31.46
Perry	55	11,726	1.06	.90	13.94	131.66	30.88
Pike	5	11,718	.81	.69	12.40	111.40	26.11
Unknown[1]	289	11,620	1.72	1.48	12.69	132.59	30.81
Ohio	201	11,935	3.21	2.69	11.52	105.75	25.24
Belmont	190	11,951	3.22	2.69	11.58	104.88	25.07
Vinton	8	11,543	2.86	2.48	9.80	122.69	28.32
Unknown[1]	3	11,999	3.33	2.78	12.30	114.20	27.41
Pennsylvania	93	12,814	2.48	1.93	8.40	100.11	25.66
Armstrong	13	11,097	2.03	1.83	9.72	129.72	28.79
Greene	80	13,085	2.55	1.95	8.19	96.16	25.16
West Virginia	859	12,283	2.67	2.17	10.49	103.49	25.42
Boone	12	12,063	.78	.65	13.32	132.86	32.05
Brooke	67	11,531	3.18	2.76	13.81	125.60	28.97
Fayette	3	11,947	2.66	2.23	16.59	144.55	34.54
Kanawha	44	12,208	1.00	.82	12.53	137.28	33.52
Logan	5	11,833	.91	.77	9.72	190.21	45.01
Marshall	578	12,218	2.90	2.37	10.43	92.50	22.60
Monongalia	122	13,249	2.39	1.80	6.94	116.56	30.89
Raleigh	4	11,442	1.03	.90	16.60	176.30	40.34
Wayne	13	11,326	.63	.55	15.12	135.46	30.68
Unknown[1]	12	11,843	2.99	2.52	12.50	124.30	29.44
Cincinnati Gas & Electric Co Miami Fort	**2,806**	**12,130**	**1.46**	**1.20**	**11.82**	**122.54**	**29.73**
Illinois	39	12,414	2.53	2.04	8.58	140.63	34.92
Gallatin	31	12,472	2.72	2.18	9.03	134.28	33.49
Saline	7	12,319	1.58	1.28	6.70	176.20	43.41
White	1	11,596	2.76	2.38	7.40	112.60	26.11
Indiana	84	11,028	1.57	1.43	8.74	132.37	29.20
Daviess	2	11,461	1.28	1.12	6.90	133.10	30.51
Gibson	14	10,832	1.65	1.52	9.40	98.80	21.40
Pike	12	11,458	1.50	1.31	7.38	122.31	28.03
Sullivan	46	10,977	1.69	1.54	9.07	145.02	31.84
Vigo	5	11,022	.46	.42	7.03	133.70	29.47
Unknown[1]	5	10,918	1.75	1.60	9.40	132.90	29.02
Kentucky	665	11,836	1.15	.97	12.82	134.95	31.94
Breathitt	8	11,911	2.10	1.76	12.80	143.60	34.21
Floyd	5	11,638	.88	.75	15.20	121.14	28.19
Johnson	41	12,988	.70	.54	7.93	122.86	31.91
Lawrence	10	11,207	1.36	1.21	15.20	178.69	40.05
Martin	52	11,745	1.52	1.30	11.76	128.49	30.18
Ohio	2	11,798	1.95	1.65	10.70	141.00	33.27
Perry	109	11,675	1.06	.91	14.20	127.89	29.86
Pike	24	11,897	.81	.68	13.08	165.54	39.39
Unknown[1]	415	11,787	1.17	.99	12.99	136.14	32.09

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Cincinnati Gas & Electric Co Miami Fort							
Ohio	18	11,511	2.72	2.36	13.62	111.02	25.56
Belmont	14	11,510	2.43	2.11	13.49	107.20	24.68
Coshocton	4	11,513	3.76	3.27	14.10	124.90	28.76
Pennsylvania	112	12,980	2.32	1.79	8.17	97.18	25.23
Armstrong	3	10,972	1.78	1.62	9.90	132.30	29.03
Greene	109	13,042	2.33	1.79	8.12	96.26	25.11
West Virginia	1,888	12,233	1.48	1.21	11.87	119.24	29.17
Boone	362	11,963	.71	.60	14.10	134.85	32.27
Brooke	5	11,514	2.94	2.55	13.87	124.70	28.72
Clay	7	9,981	1.90	1.90	20.30	128.43	25.64
Fayette	5	11,873	1.90	1.60	15.05	143.39	34.05
Kanawha	647	12,041	.75	.63	13.28	124.01	29.86
Logan	27	11,734	.89	.75	13.72	142.00	33.32
Marshall	408	12,271	2.84	2.31	10.33	91.61	22.48
Monongalia	278	13,263	2.36	1.78	6.81	116.20	30.82
Raleigh	36	11,661	1.08	.92	16.16	173.76	40.53
Wayne	73	11,314	.62	.55	15.00	135.02	30.55
Webster	40	13,324	2.18	1.64	6.70	117.70	31.36
Cincinnati Gas & Electric Co Beckjord	**2,676**	**11,815**	**1.13**	**.96**	**12.92**	**128.97**	**30.48**
Illinois	5	11,941	1.67	1.40	6.50	181.80	43.42
Saline	5	11,941	1.67	1.40	6.50	181.80	43.42
Indiana	13	11,008	.96	.88	8.96	93.64	20.62
Knox	9	10,875	.51	.47	8.30	73.00	15.88
Pike	4	11,278	1.88	1.67	10.30	133.90	30.20
Kentucky	2,052	11,718	.98	.84	13.18	130.43	30.57
Breathitt	13	11,966	1.71	1.43	12.98	141.70	33.91
Floyd	7	12,055	1.00	.83	12.77	111.87	26.97
Johnson	7	12,636	.72	.57	8.48	121.98	30.83
Knott	4	11,482	.68	.59	17.10	184.00	42.25
Lawrence	18	11,168	1.35	1.21	14.40	176.47	39.42
Martin	21	11,825	1.15	.97	10.85	118.24	27.96
Perry	542	11,674	.98	.84	14.13	133.01	31.06
Pike	13	11,938	1.18	.99	11.75	119.86	28.62
Unknown[1]	1,426	11,730	.97	.83	12.87	129.09	30.29
Ohio	22	12,276	3.53	2.88	9.97	106.54	26.16
Belmont	19	12,383	3.70	2.99	9.71	103.65	25.67
Tuscarawas	2	11,385	2.18	1.91	13.70	131.80	30.01
Vinton	2	12,070	3.14	2.60	8.40	113.40	27.37
Pennsylvania	39	13,066	2.38	1.82	8.03	95.81	25.04
Greene	39	13,066	2.38	1.82	8.03	95.81	25.04
West Virginia	544	12,089	1.49	1.24	12.60	127.43	30.81
Boone	115	11,575	.75	.65	15.50	138.91	32.16
Brooke	5	11,633	2.94	2.53	13.55	118.34	27.53
Clay	3	9,353	1.89	2.02	24.12	132.49	24.78
Fayette	9	11,996	1.39	1.16	13.79	142.94	34.29
Kanawha	168	11,888	1.04	.87	14.57	134.49	31.98
Logan	44	11,694	.90	.77	12.47	149.22	34.90
Marshall	83	12,341	2.87	2.32	10.05	90.86	22.43
Monongalia	98	13,173	2.27	1.72	7.02	116.12	30.59
Raleigh	20	11,742	1.09	.92	15.30	171.45	40.26
Wayne	*	11,037	.64	.58	16.00	136.90	30.22
Cincinnati Gas & Electric Co Zimmer	**3,753**	**12,108**	**3.49**	**2.88**	**9.81**	**108.05**	**26.16**
Indiana	12	10,887	1.84	1.69	9.41	101.81	22.17
Gibson	8	10,756	1.75	1.63	9.58	100.28	21.57
Pike	3	11,207	2.07	1.85	9.00	105.40	23.62
Kentucky	175	11,715	1.84	1.57	12.87	127.74	29.93
Breathitt	2	11,591	2.54	2.19	12.70	144.40	33.47
Lawrence	3	11,240	1.37	1.22	15.40	178.70	40.17
Martin	3	12,049	1.32	1.10	10.40	113.50	27.35
Perry	43	11,584	.97	.84	14.34	123.85	28.69
Unknown[1]	124	11,766	2.15	1.83	12.37	127.93	30.10

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Cincinnati Gas & Electric Co Zimmer							
Ohio	3,154	12,077	3.71	3.07	9.67	107.58	25.98
Belmont	2,127	12,356	3.91	3.16	9.60	100.80	24.91
Jefferson	47	11,969	3.33	2.78	12.31	120.22	28.78
Tuscarawas	2	11,301	1.93	1.71	13.00	135.30	30.58
Vinton	979	11,478	3.31	2.89	9.68	122.74	28.18
Pennsylvania	77	13,012	2.30	1.77	7.86	99.17	25.81
Greene	74	13,011	2.33	1.79	7.88	97.60	25.40
Washington	3	13,018	1.44	1.11	7.40	136.40	35.51
West Virginia	334	12,436	2.59	2.09	10.00	104.97	26.11
Boone	7	11,828	.66	.56	14.40	146.02	34.54
Brooke	16	11,342	2.89	2.55	14.10	124.86	28.32
Clay	3	11,172	1.21	1.08	18.90	106.40	23.77
Kanawha	20	12,189	1.42	1.16	13.91	127.14	30.99
Marshall	181	12,256	2.89	2.36	10.30	91.03	22.31
Monongalia	99	13,149	2.57	1.95	6.82	114.93	30.22
Raleigh	7	11,733	.91	.77	16.76	170.48	40.00
Wayne	1	11,037	.64	.58	16.00	136.80	30.20
Colorado Springs City of Drake	**987**	**10,521**	**.46**	**.44**	**8.10**	**89.40**	**18.81**
Colorado	727	11,258	.49	.44	9.05	95.40	21.48
Moffat	13	10,489	.37	.35	5.21	127.20	26.68
Routt	714	11,272	.50	.44	9.12	94.86	21.38
Wyoming	260	8,458	.37	.43	5.44	67.05	11.34
Campbell	260	8,458	.37	.43	5.44	67.05	11.34
Colorado Springs City of Nixon	**970**	**9,163**	**.27**	**.29**	**5.29**	**77.65**	**14.23**
Colorado	132	11,280	.49	.43	8.69	99.19	22.38
Routt	132	11,280	.49	.43	8.69	99.19	22.38
Wyoming	839	8,831	.23	.27	4.76	73.33	12.95
Campbell	839	8,831	.23	.27	4.76	73.33	12.95
Columbia City of Columbia	**30**	**13,408**	**1.10**	**.82**	**6.13**	**206.58**	**55.40**
Kentucky	30	13,408	1.10	.82	6.13	206.58	55.40
Bell	30	13,408	1.10	.82	6.13	206.58	55.40
Columbus Southern Power Co Picway	**196**	**11,532**	**2.71**	**2.35**	**8.74**	**111.97**	**25.83**
Ohio	196	11,532	2.71	2.35	8.74	111.97	25.83
Coshocton	3	12,126	2.47	2.04	10.10	149.50	36.26
Jackson	178	11,566	2.72	2.35	8.42	111.87	25.88
Perry	16	11,055	2.57	2.33	12.12	106.13	23.47
Columbus Southern Power Co Conesville	**3,849**	**11,681**	**2.38**	**2.04**	**9.59**	**130.40**	**30.47**
Ohio	3,849	11,681	2.38	2.04	9.59	130.40	30.47
Belmont	48	11,217	3.15	2.80	15.14	97.47	21.87
Coshocton	2,630	11,692	2.14	1.83	8.82	137.09	32.06
Harrison	520	12,379	2.18	1.76	8.74	117.88	29.19
Muskingum	181	11,244	2.83	2.52	13.63	110.44	24.83
Perry	132	11,552	3.86	3.34	12.77	106.58	24.62
Tuscarawas	338	10,872	3.62	3.33	12.74	122.08	26.55
Consumers Power Co Campbell	**4,030**	**10,359**	**.47**	**.46**	**7.66**	**140.22**	**29.05**
Kentucky	577	12,939	.71	.55	7.98	184.97	47.86
Floyd	548	12,933	.71	.55	7.98	181.31	46.90
Letcher	20	13,109	.72	.55	8.05	257.40	67.48
Perry	9	12,884	.96	.75	8.10	243.60	62.77
West Virginia	1,162	12,175	.76	.62	12.21	167.22	40.72
Boone	1,052	12,136	.75	.62	12.27	166.66	40.45
Logan	11	12,515	.69	.55	9.90	260.40	65.18
Nicholas	99	12,558	.82	.65	11.77	163.12	40.97
Wyoming	2,291	8,788	.27	.31	5.28	104.67	18.40
Campbell	2,278	8,788	.27	.31	5.28	104.72	18.41
Converse	13	8,824	.33	.37	5.20	95.60	16.87
Consumers Power Co Cobb	**1,055**	**9,382**	**.54**	**.58**	**6.89**	**125.82**	**23.61**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Consumers Power Co Cobb							
Montana	877	9,039	0.51	0.56	6.59	116.29	21.02
Big Horn	877	9,039	.51	.56	6.59	116.29	21.02
West Virginia	109	12,515	1.00	.80	10.40	186.31	46.63
Boone	22	12,152	.86	.71	12.62	173.43	42.15
Mingo	26	12,953	.98	.76	7.40	267.10	69.19
Nicholas	61	12,461	1.06	.85	10.87	154.89	38.60
Wyoming	69	8,779	.26	.30	5.18	113.90	20.00
Campbell	69	8,779	.26	.30	5.18	113.90	20.00
Consumers Power Co Karn	**1,222**	**8,808**	**.26**	**.29**	**4.96**	**108.19**	**19.06**
Wyoming	1,222	8,808	.26	.29	4.96	108.19	19.06
Campbell	1,209	8,809	.26	.30	4.97	108.21	19.06
Converse	13	8,670	.18	.21	4.30	106.90	18.54
Consumers Power Co Weadock	**1,722**	**10,627**	**.57**	**.54**	**8.58**	**140.49**	**29.86**
Kentucky	9	12,650	.76	.60	10.30	240.50	60.85
Perry	9	12,650	.76	.60	10.30	240.50	60.85
Montana	236	9,034	.51	.56	6.68	122.08	22.06
Big Horn	236	9,034	.51	.56	6.68	122.08	22.06
West Virginia	865	12,306	.82	.67	11.73	159.59	39.28
Boone	539	12,117	.83	.69	12.16	156.94	38.03
Mingo	27	13,112	.97	.74	7.20	260.70	68.37
Nicholas	299	12,575	.80	.64	11.37	154.75	38.92
Wyoming	611	8,836	.23	.26	4.82	107.90	19.07
Campbell	611	8,836	.23	.26	4.82	107.90	19.07
Consumers Power Co Whiting	**988**	**9,994**	**.49**	**.49**	**7.75**	**132.09**	**26.40**
Kentucky	40	12,832	.80	.62	8.85	196.26	50.37
Floyd	30	12,801	.80	.62	9.18	185.44	47.48
Perry	10	12,928	.79	.61	7.80	230.10	59.49
West Virginia	320	12,123	.84	.69	12.12	149.45	36.24
Boone	310	12,108	.83	.69	12.16	149.42	36.18
Nicholas	10	12,597	.91	.72	11.10	150.40	37.89
Wyoming	627	8,725	.29	.33	5.44	113.76	19.85
Campbell	615	8,725	.29	.33	5.44	113.79	19.86
Converse	12	8,766	.33	.38	5.60	112.20	19.67
Coop Power Assn Coal Creek	**7,670**	**6,198**	**.61**	**.98**	**11.27**	**75.17**	**9.32**
North Dakota	7,670	6,198	.61	.98	11.27	75.17	9.32
Mclean	7,670	6,198	.61	.98	11.27	75.17	9.32
Dairyland Power Coop Alma-Madgett	**1,691**	**9,248**	**.35**	**.38**	**4.59**	**109.70**	**20.29**
Illinois	110	12,056	1.50	1.25	6.30	129.82	31.30
Franklin	5	11,994	1.44	1.20	6.30	188.50	45.22
Jefferson	105	12,059	1.51	1.25	6.30	127.22	30.68
Indiana	45	11,697	1.48	1.26	5.05	181.98	42.57
Pike	45	11,697	1.48	1.26	5.05	181.98	42.57
Kentucky	14	11,851	1.64	1.39	12.20	173.05	41.02
Webster	14	11,851	1.64	1.39	12.20	173.05	41.02
Utah	30	12,828	1.17	.91	6.95	176.99	45.41
Carbon	30	12,828	1.17	.91	6.95	176.99	45.41
Wyoming	1,492	8,871	.20	.22	4.33	102.06	18.11
Campbell	1,492	8,871	.20	.22	4.33	102.06	18.11
Dairyland Power Coop Genoa No.3	**835**	**11,074**	**.97**	**.87**	**5.60**	**143.24**	**31.72**
Illinois	374	11,981	1.45	1.21	6.37	134.49	32.23
Franklin	57	12,074	1.40	1.16	6.36	183.82	44.39
Jefferson	317	11,965	1.45	1.22	6.37	125.56	30.05
Indiana	100	11,634	1.19	1.02	4.71	180.41	41.98
Pike	100	11,634	1.19	1.02	4.71	180.41	41.98
Utah	101	12,685	.95	.75	7.09	182.20	46.22
Carbon	101	12,685	.95	.75	7.09	182.20	46.22
Wyoming	259	8,921	.20	.22	4.27	119.92	21.40
Campbell	259	8,921	.20	.22	4.27	119.92	21.40
Dayton Power & Light Co Stuart	**5,724**	**11,504**	**.88**	**.77**	**14.60**	**124.44**	**28.63**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Dayton Power & Light Co Stuart							
Kentucky	1,742	11,311	0.88	0.77	15.36	108.11	24.46
Floyd	16	12,171	.81	.67	11.80	224.50	54.65
Lawrence	153	11,075	.83	.75	15.18	119.17	26.40
Martin	1,513	11,331	.86	.76	15.42	103.61	23.48
Morgan	61	11,193	1.33	1.19	15.15	160.87	36.01
West Virginia	3,982	11,588	.89	.76	14.28	131.41	30.46
Boone	964	11,742	.84	.72	15.40	106.41	24.99
Kanawha	56	12,030	1.28	1.06	12.52	170.19	40.95
Logan	25	11,124	.90	.81	14.56	184.77	41.11
Mingo	1,373	11,520	.94	.81	13.56	153.27	35.31
Nicholas	499	11,791	.88	.75	12.61	139.07	32.79
Wayne	992	11,417	.84	.74	15.02	114.15	26.07
Wyoming	73	11,612	.85	.73	15.33	186.64	43.35
Dayton Power & Light Co Hutchings	471	12,377	.81	.65	11.34	178.08	44.08
Kentucky	38	12,607	.80	.64	9.04	223.75	56.42
Boyd	10	12,034	.81	.67	11.60	214.00	51.51
Perry	28	12,810	.80	.63	8.14	227.00	58.16
West Virginia	433	12,357	.81	.65	11.55	174.02	43.01
Mingo	172	12,322	.83	.68	11.74	196.83	48.50
Nicholas	252	12,376	.79	.64	11.49	156.44	38.72
Wayne	9	12,502	.86	.69	9.20	232.00	58.01
Dayton Power & Light Co Killen	1,681	11,736	.65	.55	14.04	131.90	30.96
Kentucky	296	11,728	.63	.54	14.39	125.10	29.34
Knott	49	12,447	.67	.54	10.04	177.75	44.25
Martin	49	11,566	.64	.56	13.51	117.89	27.27
Pike	198	11,591	.62	.53	15.69	112.93	26.18
West Virginia	1,384	11,737	.65	.56	13.97	133.36	31.30
Boone	99	11,701	.66	.56	12.75	174.43	40.82
Kanawha	5	12,466	.63	.51	11.20	191.60	47.77
Logan	587	11,904	.65	.55	13.76	120.14	28.60
Nicholas	41	11,691	.62	.53	14.34	173.93	40.67
Wayne	560	11,518	.65	.57	14.69	128.65	29.64
Unknown[1]	92	12,024	.67	.56	12.20	180.00	43.29
Delmarva Power & Light Co Edgemoor	24	12,572	.67	.53	11.56	216.91	54.54
Kentucky	10	12,473	.65	.52	10.23	248.18	61.91
Pike	10	12,473	.65	.52	10.23	248.18	61.91
West Virginia	14	12,642	.69	.55	12.50	195.00	49.30
Wyoming	14	12,642	.69	.55	12.50	195.00	49.30
Deseret Generation & Tran Coop Bonanza	2,028	9,929	.40	.40	10.15	156.72	31.12
Colorado	2,028	9,929	.40	.40	10.15	156.72	31.12
Rio Blanco	2,028	9,929	.40	.40	10.15	156.72	31.12
Detroit Edison Co Belle River	3,348	9,510	.35	.37	4.22	133.67	25.43
Montana	3,348	9,510	.35	.37	4.22	133.67	25.43
Big Horn	3,348	9,510	.35	.37	4.22	133.67	25.43
Detroit Edison Co Harbor Beach	101	13,085	.97	.74	7.21	135.77	35.53
Kentucky	101	13,085	.97	.74	7.21	135.74	35.52
Pike	101	13,085	.97	.74	7.21	135.74	35.52
West Virginia	*	13,034	.92	.71	6.60	161.60	42.13
Mingo	*	13,034	.92	.71	6.60	161.60	42.13
Detroit Edison Co Marysville	32	13,082	.94	.72	7.08	141.06	36.91
Kentucky	27	13,094	.95	.73	7.18	138.05	36.15
Pike	27	13,094	.95	.73	7.18	138.05	36.15
West Virginia	5	13,016	.88	.68	6.52	157.44	40.99
Mingo	5	13,016	.88	.68	6.52	157.44	40.99
Detroit Edison Co Monroe	8,796	10,463	.64	.61	6.30	118.06	24.71

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Detroit Edison Co Monroe							
Kentucky	2,028	12,782	1.06	0.83	8.31	140.49	35.92
Boyd	21	12,876	1.48	1.15	8.00	131.40	33.84
Harlan	52	12,714	1.04	.82	8.30	176.07	44.77
Knott	46	12,974	1.41	1.09	7.73	117.06	30.37
Letcher	194	13,204	1.46	1.11	7.18	173.63	45.85
Martin	410	12,712	.86	.68	8.69	132.92	33.79
Perry	522	12,709	.91	.72	8.14	135.44	34.43
Pike	783	12,754	1.13	.89	8.55	138.59	35.35
Pennsylvania	1,052	13,103	1.52	1.16	6.92	119.33	31.27
Greene	1,024	13,095	1.53	1.17	6.94	119.46	31.29
Washington	28	13,399	1.37	1.02	6.20	114.90	30.79
Virginia	76	12,783	.81	.63	8.66	161.80	41.37
Lee	70	12,803	.82	.64	8.59	156.13	39.98
Wise	6	12,547	.67	.53	9.50	229.30	57.54
West Virginia	435	12,807	.95	.74	8.59	141.87	36.34
Boone	362	12,757	.95	.74	8.92	140.41	35.82
Mingo	60	13,099	.97	.74	6.10	154.89	40.58
Raleigh	13	12,858	.99	.77	11.00	121.00	31.12
Wyoming	5,205	8,797	.26	.30	5.16	101.15	17.79
Campbell	4,752	8,793	.27	.30	5.16	101.48	17.85
Converse	453	8,836	.23	.26	5.12	97.65	17.26
Detroit Edison Co River Rouge	**1,174**	**10,759**	**.55**	**.51**	**6.65**	**126.38**	**27.20**
Kentucky	417	12,853	.84	.65	7.65	142.35	36.59
Martin	22	12,722	.74	.58	9.26	193.21	49.16
Perry	355	12,884	.85	.66	7.43	138.27	35.63
Pike	40	12,648	.84	.66	8.74	151.12	38.23
Virginia	20	13,186	.86	.65	6.70	128.10	33.78
Dickenson	20	13,186	.86	.65	6.70	128.10	33.78
West Virginia	137	12,646	.79	.63	9.39	155.66	39.37
Boone	48	12,721	.80	.63	8.99	152.12	38.70
Logan	61	12,438	.72	.58	10.53	170.88	42.51
Mingo	28	12,972	.92	.71	7.60	129.80	33.68
Wyoming	600	8,792	.28	.32	5.33	100.46	17.67
Campbell	559	8,788	.28	.32	5.33	100.26	17.62
Converse	41	8,854	.25	.29	5.26	103.15	18.27
Detroit Edison Co St Clair	**4,663**	**9,991**	**.64**	**.64**	**4.63**	**125.88**	**25.15**
Kentucky	45	12,927	1.58	1.22	8.28	155.80	40.28
Letcher	23	12,712	2.30	1.81	9.56	175.94	44.73
Pike	22	13,151	.83	.63	6.95	135.44	35.62
Montana	3,967	9,494	.35	.37	4.18	128.39	24.38
Big Horn	3,967	9,494	.35	.37	4.18	128.39	24.38
Pennsylvania	47	13,132	2.15	1.63	7.86	109.60	28.79
Greene	47	13,132	2.15	1.63	7.86	109.60	28.79
West Virginia	547	13,211	2.58	1.95	7.31	113.95	30.11
Harrison	198	13,100	3.07	2.34	7.54	113.77	29.81
Monongalia	349	13,275	2.31	1.74	7.18	114.04	30.28
Wyoming	57	8,796	.20	.23	4.40	94.20	16.57
Campbell	57	8,796	.20	.23	4.40	94.20	16.57
Detroit Edison Co Trenton Channel	**2,071**	**10,493**	**.70**	**.67**	**5.43**	**113.13**	**23.74**
Kentucky	84	12,829	1.44	1.12	8.06	142.85	36.65
Letcher	23	13,273	1.58	1.19	6.63	175.78	46.66
Pike	61	12,662	1.39	1.10	8.60	129.83	32.88
Pennsylvania	736	12,915	1.45	1.12	6.76	119.76	30.93
Greene	658	12,876	1.46	1.13	6.78	119.78	30.84
Washington	78	13,249	1.39	1.05	6.60	119.60	31.69
Wyoming	1,251	8,911	.21	.24	4.46	104.61	18.64
Campbell	1,173	8,916	.21	.23	4.41	104.78	18.68
Converse	78	8,830	.22	.25	5.27	102.03	18.02
Duke Power Co Allen	**2,173**	**12,123**	**.89**	**.73**	**12.04**	**163.68**	**39.69**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Duke Power Co Allen							
Kentucky	811	12,127	1.04	0.86	12.50	163.39	39.63
Johnson	65	12,008	1.14	.95	10.89	167.52	40.23
Martin	159	12,081	1.04	.86	11.25	143.08	34.57
Pike	587	12,153	1.03	.85	13.02	168.40	40.93
Virginia	223	12,412	1.03	.83	12.30	188.71	46.85
Buchanan	81	12,774	.99	.77	10.30	196.04	50.08
Wise	142	12,205	1.06	.87	13.45	184.34	45.00
West Virginia	1,064	12,105	.75	.62	12.00	152.27	36.86
Mingo	977	12,108	.74	.61	11.96	151.88	36.78
Nicholas	47	11,807	.78	.66	14.90	145.40	34.34
Wayne	40	12,373	.88	.72	9.47	169.24	41.88
Imported	75	11,491	.76	.66	6.79	257.29	59.13
Imported Coal	75	11,491	.76	.66	6.79	257.29	59.13
Duke Power Co Belews Creek	**5,427**	**12,259**	**.86**	**.70**	**12.23**	**151.22**	**37.08**
Kentucky	1,924	12,241	.99	.81	11.40	151.85	37.18
Johnson	169	12,024	1.11	.92	10.69	171.42	41.22
Martin	1,284	12,222	.98	.80	11.42	141.05	34.48
Pike	471	12,370	.96	.77	11.59	174.14	43.08
Virginia	214	12,617	.93	.74	11.27	172.95	43.64
Buchanan	109	12,847	.96	.75	10.97	190.51	48.95
Tazewell	77	12,195	.84	.69	12.09	141.00	34.39
Wise	28	12,881	1.04	.81	10.22	187.95	48.42
West Virginia	3,289	12,246	.78	.64	12.77	149.40	36.59
Mercer	312	12,596	.85	.68	12.08	194.35	48.96
Mingo	1,068	12,326	.78	.64	11.47	152.88	37.69
Nicholas	1,894	12,135	.77	.63	13.65	139.07	33.75
Wyoming	15	13,248	.89	.67	8.80	224.10	59.38
Duke Power Co Buck	**724**	**11,709**	**.70**	**.60**	**16.24**	**154.92**	**36.28**
Kentucky	10	11,986	.99	.83	13.00	154.80	37.11
Pike	10	11,986	.99	.83	13.00	154.80	37.11
Virginia	120	12,593	.90	.71	11.49	204.76	51.57
Buchanan	63	12,784	.93	.73	10.63	202.17	51.69
Wise	57	12,382	.87	.70	12.43	207.71	51.44
West Virginia	594	11,526	.66	.57	17.25	143.92	33.18
Mcdowell	36	12,461	.83	.67	12.70	191.72	47.78
Mingo	546	11,434	.65	.57	17.71	139.37	31.87
Wyoming	12	12,908	.47	.36	10.00	188.90	48.77
Duke Power Co Cliffside	**1,684**	**12,503**	**.97**	**.78**	**9.41**	**157.85**	**39.47**
Kentucky	1,566	12,536	.99	.79	9.18	157.54	39.50
Floyd	223	12,545	1.08	.86	10.09	176.03	44.17
Harlan	324	12,820	1.02	.80	7.01	166.25	42.63
Knox	113	12,658	1.14	.90	8.97	220.20	55.75
Perry	384	12,479	.85	.68	9.37	135.00	33.69
Pike	512	12,370	.99	.80	10.06	147.02	36.37
Whitley	10	12,506	.86	.69	8.60	134.60	33.67
Virginia	10	12,626	.89	.70	9.60	188.80	47.68
Dickenson	10	12,626	.89	.70	9.60	188.80	47.68
West Virginia	108	12,003	.78	.65	12.81	159.43	38.27
Boone	27	11,643	.84	.72	14.37	215.07	50.08
Logan	81	12,123	.75	.62	12.28	141.62	34.34
Duke Power Co Dan River	**208**	**12,818**	**.65**	**.50**	**9.63**	**161.09**	**41.30**
Kentucky	37	12,417	.80	.65	10.81	168.05	41.73
Pike	37	12,417	.80	.65	10.81	168.05	41.73
West Virginia	171	12,905	.61	.47	9.37	159.64	41.20
Mingo	109	12,819	.69	.54	9.78	148.20	37.99
Wyoming	62	13,056	.47	.36	8.66	179.40	46.85
Duke Power Co Lee	**572**	**12,134**	**.89**	**.73**	**12.39**	**180.34**	**43.77**
Kentucky	365	12,223	.96	.79	11.56	183.95	44.97
Floyd	71	12,402	1.00	.81	11.64	204.97	50.84
Harlan	36	12,311	1.04	.84	11.00	207.61	51.12
Knott	99	12,047	.97	.80	12.25	185.39	44.67

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Duke Power Co Lee							
Kentucky							
Knox	27	12,819	1.09	0.85	8.57	218.10	55.92
Perry	71	12,184	.89	.73	10.92	156.97	38.25
Pike	61	12,029	.91	.75	12.77	157.82	37.97
Virginia	42	12,297	.84	.68	13.94	202.15	49.72
Buchanan	2	13,657	1.11	.81	7.60	188.20	51.40
Dickenson	40	12,229	.82	.67	14.26	202.93	49.63
West Virginia	165	11,898	.74	.63	13.82	166.38	39.59
Boone	53	12,093	.72	.60	12.26	181.39	43.87
Logan	95	11,908	.69	.58	13.32	160.84	38.31
Raleigh	17	11,233	1.12	1.00	21.50	148.77	33.42
Duke Power Co Marshall	**5,428**	**12,295**	**.86**	**.70**	**11.18**	**157.26**	**38.67**
Kentucky	2,285	12,289	.99	.80	10.86	163.47	40.18
Floyd	360	12,413	1.01	.81	10.94	187.74	46.61
Harlan	115	12,761	1.06	.83	7.52	167.20	42.67
Johnson	427	11,963	1.14	.95	10.84	165.42	39.58
Knott	96	12,059	1.13	.93	11.41	181.78	43.84
Knox	75	12,664	1.18	.93	9.40	212.59	53.84
Letcher	21	12,574	.74	.59	7.84	201.32	50.63
Martin	11	12,940	.75	.58	7.90	212.20	54.92
Perry	467	12,153	.85	.70	11.26	130.95	31.83
Pike	684	12,410	.93	.75	11.45	162.10	40.23
Whitley	29	12,402	.97	.78	8.03	129.06	32.01
Virginia	313	12,383	.96	.77	10.65	167.98	41.60
Buchanan	50	12,877	.96	.74	10.19	197.30	50.81
Lee	221	12,208	.93	.76	10.65	159.02	38.83
Tazewell	11	12,417	.59	.48	13.40	135.30	33.60
Wise	31	12,827	1.27	.99	10.37	192.50	49.38
West Virginia	2,793	12,300	.75	.61	11.57	149.61	36.80
Boone	277	11,998	.79	.66	12.91	176.09	42.25
Clay	20	12,241	.79	.65	11.85	199.10	48.74
Kanawha	83	12,325	.89	.72	11.10	130.48	32.16
Logan	280	12,144	.76	.62	12.04	140.68	34.17
Mcdowell	13	12,417	.79	.64	11.66	189.40	47.04
Mingo	1,874	12,357	.73	.59	11.47	147.32	36.41
Nicholas	151	12,408	.78	.63	10.95	143.02	35.49
Wayne	95	12,312	.83	.67	9.50	157.29	38.73
Imported	37	11,561	.84	.73	6.50	266.00	61.50
Imported Coal	37	11,561	.84	.73	6.50	266.00	61.50
Duke Power Co Riverbend	**1,179**	**12,109**	**.97**	**.80**	**12.35**	**162.91**	**39.45**
Kentucky	563	12,242	1.03	.84	11.05	180.48	44.19
Bell	9	11,746	.98	.83	14.60	186.60	43.84
Floyd	17	12,590	1.09	.86	10.42	188.02	47.34
Harlan	67	12,996	1.06	.81	6.57	174.20	45.28
Knott	195	12,116	1.17	.97	10.89	202.76	49.13
Knox	28	12,669	1.13	.89	9.21	217.61	55.14
Perry	138	12,127	.88	.72	11.87	169.30	41.06
Pike	109	12,025	.92	.77	13.31	146.97	35.35
Virginia	329	12,405	.95	.77	10.20	139.27	34.55
Dickenson	19	12,610	1.21	.96	13.07	170.50	43.00
Lee	310	12,392	.94	.76	10.02	137.32	34.03
West Virginia	287	11,512	.88	.77	17.38	155.48	35.80
Boone	62	12,210	.86	.70	12.65	172.64	42.16
Kanawha	75	10,552	.70	.66	22.95	144.02	30.39
Logan	50	12,057	.87	.72	13.16	176.19	42.48
Raleigh	100	11,526	1.04	.90	18.25	141.24	32.56
East Kentucky Power Coop Inc Cooper	**931**	**12,328**	**1.34**	**1.08**	**10.32**	**131.34**	**32.38**
Kentucky	931	12,328	1.34	1.08	10.32	131.34	32.38
Bell	52	12,758	1.68	1.31	9.49	126.92	32.38
Breathitt	50	12,455	1.19	.95	9.07	149.44	37.23
Leslie	5	12,798	1.62	1.27	8.98	117.65	30.11
Perry	117	12,553	1.03	.82	10.07	129.33	32.47
Pulaski	695	12,249	1.37	1.12	10.54	130.85	32.06
Whitley	12	12,116	1.33	1.10	9.93	128.79	31.21

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
East Kentucky Power Coop Inc Dale	**564**	**12,270**	**0.80**	**0.65**	**9.98**	**129.17**	**31.70**
Kentucky	564	12,270	.80	.65	9.98	129.17	31.70
Breathitt	30	12,321	.71	.58	8.83	119.40	29.42
Floyd	6	12,604	.78	.62	9.07	135.40	34.13
Knott	4	12,423	.85	.68	11.05	120.80	30.01
Laurel	1	11,033	.66	.60	16.10	107.70	23.77
Lawrence	112	12,101	.97	.80	9.38	145.71	35.26
Perry	411	12,310	.76	.62	10.22	125.48	30.89
East Kentucky Power Coop Inc Spurlock	**2,565**	**11,982**	**.83**	**.69**	**12.32**	**136.42**	**32.69**
Kentucky	1,416	11,933	.91	.76	12.00	142.21	33.94
Boyd	345	12,239	.85	.70	11.45	156.11	38.21
Breathitt	119	11,892	1.48	1.25	12.06	173.99	41.38
Carter	62	12,048	.67	.56	12.66	122.51	29.52
Floyd	388	11,628	.90	.78	12.49	123.16	28.64
Greenup	8	12,304	.84	.68	13.10	106.60	26.23
Knott	189	11,927	.82	.69	11.36	176.83	42.18
Lawrence	172	11,891	.87	.73	12.33	130.32	30.99
Perry	105	11,928	.88	.74	12.92	101.23	24.15
Pike	28	12,532	.94	.75	8.80	136.61	34.24
West Virginia	1,149	12,042	.72	.60	12.71	129.34	31.15
Boone	203	12,093	.67	.55	12.85	151.38	36.61
Clay	113	12,098	1.07	.89	13.52	136.78	33.09
Fayette	3	11,707	.94	.80	15.00	129.60	30.34
Kanawha	336	12,093	.70	.58	12.50	125.61	30.38
Logan	450	11,986	.66	.55	12.65	120.84	28.97
Mingo	2	12,083	.71	.59	10.30	123.00	29.72
Wayne	42	11,862	.69	.58	12.06	123.16	29.22
Electric Energy Inc Joppa	**5,113**	**8,840**	**.23**	**.26**	**4.75**	**86.90**	**15.36**
Wyoming	5,113	8,840	.23	.26	4.75	86.90	15.36
Campbell	3,173	8,836	.24	.27	4.40	87.55	15.47
Converse	1,940	8,845	.22	.25	5.33	85.83	15.18
Empire District Electric Co Riverton	**150**	**9,301**	**.53**	**.57**	**4.71**	**120.31**	**22.38**
Oklahoma	17	12,586	3.08	2.45	10.32	111.44	28.05
Craig	17	12,586	3.08	2.45	10.32	111.44	28.05
Wyoming	132	8,868	.20	.22	3.98	121.96	21.63
Campbell	132	8,868	.20	.22	3.98	121.96	21.63
Empire District Electric Co Asbury	**391**	**9,567**	**.25**	**.26**	**4.90**	**112.97**	**21.61**
Utah	74	12,523	.44	.35	7.48	139.10	34.84
Emery	74	12,523	.44	.35	7.48	139.10	34.84
Wyoming	317	8,873	.20	.23	4.30	104.31	18.51
Campbell	317	8,873	.20	.23	4.30	104.31	18.51
Florida Power Corp Crystal River	**3,037**	**12,667**	**.91**	**.72**	**9.18**	**198.12**	**50.19**
Kentucky	2,791	12,686	.92	.72	8.94	193.05	48.98
Clay	49	12,143	.82	.68	10.58	268.54	65.22
Knott	566	12,764	.88	.69	8.18	200.91	51.29
Letcher	602	12,891	1.05	.82	7.96	183.98	47.43
Perry	282	12,167	.92	.76	11.74	193.88	47.18
Pike	1,293	12,691	.87	.69	9.04	190.98	48.47
West Virginia	245	12,444	.83	.67	11.94	256.96	63.95
Boone	66	12,816	.71	.56	9.38	252.84	64.81
Logan	71	12,340	.67	.54	11.88	250.07	61.72
Wyoming	108	12,284	1.00	.82	13.56	264.12	64.89
Florida Power Corp IMT Transfer[2]	**2,402**	**12,242**	**.68**	**.55**	**10.76**	**202.69**	**49.63**
Colorado	20	12,159	.38	.31	5.21	188.74	45.90
Delta	20	12,159	.38	.31	5.21	188.74	45.90
Kentucky	51	12,375	.67	.54	9.28	192.82	47.72
Martin	31	12,307	.68	.55	8.80	201.95	49.71
Pike	19	12,487	.67	.54	10.06	178.04	44.46

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Florida Power Corp IMT Transfer[2]							
West Virginia	1,833	12,212	0.68	0.56	11.77	206.12	50.34
Boone	43	12,358	.69	.56	11.67	178.04	44.00
Kanawha	1,639	12,177	.68	.56	11.96	206.22	50.22
Wayne	152	12,549	.71	.56	9.81	212.94	53.44
Imported	498	12,342	.67	.54	7.39	191.72	47.33
Imported Coal	498	12,342	.67	.54	7.39	191.72	47.33
Fremont City of Wright	**323**	**8,940**	**.23**	**.25**	**4.53**	**98.20**	**17.56**
Wyoming	323	8,940	.23	.25	4.53	98.20	17.56
Campbell	323	8,940	.23	.25	4.53	98.20	17.56
Gainesville Regional Util Deerhaven	**462**	**13,054**	**.70**	**.54**	**7.11**	**194.44**	**50.76**
Kentucky	453	13,039	.70	.54	7.14	194.30	50.67
Pike	453	13,039	.70	.54	7.14	194.30	50.67
Virginia	9	13,777	.73	.53	5.89	201.40	55.49
Dickenson	9	13,777	.73	.53	5.89	201.40	55.49
Georgia Power Co Arkwright	**184**	**12,774**	**2.11**	**1.65**	**10.77**	**157.77**	**40.30**
Virginia	184	12,774	2.11	1.65	10.77	157.77	40.30
Wise	184	12,774	2.11	1.65	10.77	157.77	40.30
Georgia Power Co Atkinson-Mcdonoug	**1,266**	**12,761**	**1.08**	**.84**	**8.71**	**142.87**	**36.46**
Kentucky	1,266	12,761	1.08	.84	8.71	142.87	36.46
Harlan	103	12,867	.96	.75	8.73	144.62	37.22
Perry	1,152	12,751	1.09	.85	8.71	142.54	36.35
Pike	11	12,805	1.27	.99	8.68	160.50	41.10
Georgia Power Co Bowen	**8,608**	**12,263**	**.98**	**.80**	**11.32**	**156.50**	**38.38**
Kentucky	7,640	12,325	1.01	.82	11.04	151.89	37.44
Bell	41	12,784	1.42	1.11	8.32	176.54	45.14
Breathitt	151	12,808	1.04	.82	8.28	197.77	50.66
Harlan	1,637	12,704	.97	.76	9.21	151.34	38.45
Knott	68	12,205	.87	.72	12.46	173.47	42.35
Letcher	1,064	12,129	1.07	.88	12.14	148.70	36.07
Perry	4,584	12,205	1.01	.83	11.59	150.90	36.83
Pike	96	12,901	.96	.74	8.12	142.93	36.88
West Virginia	825	11,792	.78	.66	14.70	191.91	45.26
Boone	764	11,741	.78	.66	14.93	186.71	43.84
Logan	62	12,422	.85	.68	11.87	252.83	62.81
Imported	142	11,651	.78	.67	6.90	210.59	49.07
Imported Coal	142	11,651	.78	.67	6.90	210.59	49.07
Georgia Power Co Hammond	**1,910**	**12,760**	**.81**	**.63**	**9.99**	**147.28**	**37.58**
Kentucky	213	12,742	1.05	.83	8.12	144.63	36.86
Harlan	24	13,085	.64	.49	9.28	147.15	38.51
Lee	46	12,968	.93	.72	7.71	149.35	38.73
Perry	118	12,517	1.22	.98	8.20	142.35	35.64
Pike	25	13,064	.84	.64	7.35	143.90	37.60
Virginia	1,348	12,758	.80	.63	10.50	146.26	37.32
Lee	844	12,599	.68	.54	11.04	148.94	37.53
Wise	504	13,026	1.00	.77	9.60	141.92	36.97
West Virginia	349	12,775	.70	.55	9.15	152.81	39.04
Mingo	349	12,775	.70	.55	9.15	152.81	39.04
Georgia Power Co Harllee Branch	**3,516**	**12,490**	**1.05**	**.84**	**10.33**	**179.95**	**44.95**
Kentucky	3,419	12,493	1.06	.85	10.30	180.44	45.09
Breathitt	486	12,808	1.22	.95	8.53	179.58	46.00
Harlan	345	12,742	.94	.74	9.32	163.25	41.60
Knott	526	12,062	1.12	.93	12.27	180.41	43.52
Letcher	83	12,723	.91	.72	8.66	162.67	41.39
Perry	488	12,315	1.00	.81	10.63	168.28	41.44
Pike	1,491	12,531	1.04	.83	10.38	189.70	47.54
Virginia	96	12,393	.71	.57	11.58	162.32	40.24
Lee	96	12,393	.71	.57	11.58	162.32	40.24
Georgia Power Co Mitchell	**203**	**12,736**	**1.03**	**.81**	**8.96**	**189.19**	**48.19**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Georgia Power Co Mitchell							
Kentucky	203	12,736	1.03	0.81	8.96	189.19	48.19
Harlan	173	12,762	.99	.77	8.89	189.18	48.29
Letcher	10	12,730	.98	.77	8.30	185.70	47.28
Perry	19	12,499	1.44	1.15	10.00	191.20	47.80
Georgia Power Co Scherer	**10,540**	**10,183**	**.42**	**.42**	**6.92**	**181.11**	**36.89**
Colorado	49	11,039	.49	.44	10.33	227.14	50.15
Routt	49	11,039	.49	.44	10.33	227.14	50.15
Kentucky	2,051	12,578	.65	.52	8.98	215.41	54.19
Harlan	258	12,545	.64	.51	10.91	164.11	41.18
Martin	1,345	12,564	.65	.52	8.39	246.48	61.94
Pike	448	12,639	.66	.52	9.65	152.02	38.43
Virginia	524	13,065	.72	.55	8.86	163.32	42.67
Lee	524	13,065	.72	.55	8.86	163.32	42.67
West Virginia	1,336	12,244	.65	.53	11.47	216.47	53.01
Mingo	1,336	12,244	.65	.53	11.47	216.47	53.01
Wyoming	6,579	8,783	.29	.33	5.18	157.46	27.66
Campbell	6,579	8,783	.29	.33	5.18	157.46	27.66
Georgia Power Co Wansley	**4,677**	**12,420**	**.90**	**.73**	**11.71**	**162.66**	**40.41**
Alabama	137	12,124	1.56	1.29	12.14	211.46	51.28
Fayette	137	12,124	1.56	1.29	12.14	211.46	51.28
Kentucky	942	11,757	1.00	.85	13.61	176.36	41.47
Bell	69	12,766	1.03	.81	8.26	154.41	39.42
Martin	295	12,049	1.06	.88	10.20	224.18	54.02
Perry	505	11,344	.97	.86	16.56	146.42	33.22
Pike	73	12,474	.94	.76	12.11	199.20	49.70
Virginia	2,963	12,640	.89	.70	11.17	157.60	39.84
Lee	1,160	12,536	.68	.54	11.42	157.40	39.46
Wise	1,802	12,707	1.02	.81	11.01	157.73	40.09
West Virginia	636	12,443	.69	.55	11.32	157.19	39.12
Mingo	611	12,436	.69	.55	11.34	152.47	37.92
Nicholas	24	12,621	.68	.54	10.89	274.35	69.25
Georgia Power Co Yates	**2,736**	**12,611**	**1.10**	**.87**	**11.18**	**163.21**	**41.16**
Kentucky	416	12,518	.98	.78	11.12	187.28	46.89
Bell	58	13,014	1.00	.77	7.70	153.16	39.86
Harlan	12	13,525	.65	.48	8.47	152.10	41.14
Perry	23	12,470	1.10	.88	8.27	159.32	39.74
Pike	323	12,393	.98	.79	12.04	197.21	48.88
Virginia	1,960	12,617	1.16	.92	11.33	157.23	39.68
Lee	842	12,467	.67	.54	11.60	153.98	38.39
Tazewell	25	12,699	.86	.68	11.42	152.80	38.81
Wise	1,094	12,730	1.54	1.21	11.12	159.78	40.68
West Virginia	360	12,684	.93	.73	10.46	168.10	42.64
Boone	70	12,775	.78	.61	9.08	199.40	50.95
Mingo	289	12,661	.96	.76	10.79	160.42	40.62
Grand Haven City of J B Simms	**205**	**12,762**	**2.35**	**1.84**	**10.07**	**133.29**	**34.02**
Pennsylvania	205	12,762	2.35	1.84	10.07	133.29	34.02
Greene	205	12,762	2.35	1.84	10.07	133.29	34.02
Grand Island City of Platte	**449**	**8,784**	**.29**	**.33**	**5.44**	**72.20**	**12.68**
Wyoming	449	8,784	.29	.33	5.44	72.20	12.68
Campbell	449	8,784	.29	.33	5.44	72.20	12.68
Grand River Dam Authority GRDA 1	**3,489**	**8,445**	**.34**	**.40**	**5.22**	**88.60**	**14.96**
Wyoming	3,489	8,445	.34	.40	5.22	88.60	14.96
Campbell	3,489	8,445	.34	.40	5.22	88.60	14.96
Gulf Power Co Crist	**2,110**	**12,073**	**1.11**	**.92**	**6.52**	**157.39**	**38.00**
Alabama	3	11,810	.99	.84	14.00	185.34	43.78
Walker	3	11,810	.99	.84	14.00	185.34	43.78

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Gulf Power Co Crist							
Colorado	114	11,965	0.48	0.40	9.25	195.11	46.69
Delta	46	11,869	.38	.32	8.32	202.58	48.09
Gunnison	68	12,029	.55	.46	9.87	190.14	45.74
Illinois	1,712	12,091	1.21	1.00	6.30	150.17	36.31
Jefferson	238	12,054	1.47	1.22	6.53	127.07	30.63
Saline	1,473	12,097	1.17	.96	6.26	153.89	37.23
Kentucky	42	11,606	1.44	1.24	13.54	193.17	44.84
Wayne	29	11,587	1.49	1.29	13.70	193.20	44.77
Webster	14	11,647	1.34	1.15	13.20	193.10	44.98
West Virginia	47	13,142	.69	.52	7.77	202.60	53.25
Fayette	47	13,142	.69	.52	7.77	202.60	53.25
Imported	191	11,824	.66	.56	4.89	179.96	42.56
Imported Coal	191	11,824	.66	.56	4.89	179.96	42.56
Gulf Power Co Scholtz	**160**	**12,709**	**.93**	**.73**	**9.46**	**159.64**	**40.58**
Kentucky	160	12,709	.93	.73	9.46	159.64	40.58
Harlan	135	12,719	.94	.74	9.34	160.06	40.72
Letcher	25	12,654	.87	.68	10.13	157.37	39.83
Gulf Power Co Smith	**1,043**	**12,254**	**.83**	**.68**	**6.53**	**169.00**	**41.42**
Colorado	18	11,969	.36	.30	7.70	166.80	39.93
Delta	18	11,969	.36	.30	7.70	166.80	39.93
Illinois	347	12,110	1.13	.93	6.23	157.19	38.07
Saline	347	12,110	1.13	.93	6.23	157.19	38.07
West Virginia	13	13,165	.73	.55	8.10	199.70	52.58
Fayette	13	13,165	.73	.55	8.10	199.70	52.58
Imported	666	12,319	.70	.57	6.63	174.49	42.99
Imported Coal	666	12,319	.70	.57	6.63	174.49	42.99
Gulf States Utilities Co Nelson	**2,511**	**8,784**	**.38**	**.43**	**5.22**	**113.69**	**19.97**
Wyoming	2,511	8,784	.38	.43	5.22	113.69	19.97
Campbell	2,511	8,784	.38	.43	5.22	113.69	19.97
Hamilton City of Hamilton	**150**	**12,160**	**.98**	**.80**	**12.52**	**147.52**	**35.88**
Kentucky	110	12,094	.72	.59	12.97	147.97	35.79
Letcher	110	12,094	.72	.59	12.97	147.97	35.79
West Virginia	40	12,339	1.69	1.37	11.29	146.31	36.11
Boone	21	12,128	.68	.56	12.37	165.96	40.26
Marshall	19	12,565	2.77	2.20	10.15	125.97	31.66
Hastings City of Hastings	**332**	**8,763**	**.29**	**.33**	**5.63**	**67.30**	**11.80**
Wyoming	332	8,763	.29	.33	5.63	67.30	11.80
Campbell	332	8,763	.29	.33	5.63	67.30	11.80
Holland City of James De Young	**146**	**12,556**	**.86**	**.68**	**8.25**	**169.53**	**42.57**
Colorado	32	11,494	.92	.80	7.65	190.00	43.68
Routt	32	11,494	.92	.80	7.65	190.00	43.68
Kentucky	101	12,845	.84	.65	8.44	164.51	42.26
Pike	101	12,845	.84	.65	8.44	164.51	42.26
Pennsylvania	13	12,891	.83	.64	8.20	164.00	42.28
Armstrong	13	12,891	.83	.64	8.20	164.00	42.28
Hoosier Energy R E C Inc Merom	**3,027**	**11,145**	**3.16**	**2.83**	**10.20**	**102.53**	**22.86**
Indiana	3,027	11,145	3.16	2.83	10.20	102.53	22.86
Daviess	366	11,062	2.98	2.69	10.14	95.30	21.09
Gibson	175	11,185	3.94	3.52	10.92	98.33	22.00
Knox	972	11,116	2.74	2.46	9.51	105.24	23.40
Pike	1,023	11,295	3.93	3.48	10.75	103.38	23.35
Sullivan	438	10,991	2.09	1.90	9.80	102.68	22.57
Vigo	53	10,479	3.43	3.28	13.26	98.71	20.69
Hoosier Energy R E C Inc Frank E Ratts	**709**	**11,193**	**1.36**	**1.21**	**8.84**	**104.62**	**23.42**
Indiana	709	11,193	1.36	1.21	8.84	104.62	23.42
Pike	709	11,193	1.36	1.21	8.84	104.62	23.42
IES Utilities Co 6th St	**238**	**11,221**	**.36**	**.32**	**7.30**	**133.07**	**29.86**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
IES Utilities Co 6th St							
Colorado	238	11,221	0.36	0.32	7.30	133.07	29.86
Delta	105	11,832	.36	.31	8.71	129.24	30.58
Mesa	24	12,159	.54	.45	8.16	133.05	32.36
Moffat	108	10,413	.31	.30	5.73	137.31	28.60
IES Utilities Co Burlington	**757**	**8,320**	**.36**	**.43**	**5.49**	**85.13**	**14.17**
Wyoming	757	8,320	.36	.43	5.49	85.13	14.17
Campbell	757	8,320	.36	.43	5.49	85.13	14.17
IES Utilities Co Ottumwa	**2,954**	**8,397**	**.33**	**.40**	**5.47**	**88.49**	**14.86**
Wyoming	2,954	8,397	.33	.40	5.47	88.49	14.86
Campbell	2,954	8,397	.33	.40	5.47	88.49	14.86
IES Utilities Co Prairie Creek 1-4	**763**	**8,550**	**.31**	**.36**	**5.66**	**86.08**	**14.72**
Wyoming	763	8,550	.31	.36	5.66	86.08	14.72
Campbell	763	8,550	.31	.36	5.66	86.08	14.72
IES Utilities Co Sutherland	**570**	**9,102**	**.35**	**.39**	**5.70**	**81.13**	**14.77**
Colorado	36	12,214	.62	.50	11.10	119.09	29.09
Gunnison	36	12,214	.62	.50	11.10	119.09	29.09
Utah	24	11,407	.37	.33	7.84	127.09	29.00
Carbon	12	11,311	.38	.34	8.80	127.60	28.87
Sevier	12	11,503	.37	.32	6.89	126.60	29.13
Wyoming	509	8,771	.33	.38	5.22	74.51	13.07
Campbell	509	8,771	.33	.38	5.22	74.51	13.07
Independence City of Blue Valley	**109**	**11,252**	**2.74**	**2.43**	**11.89**	**174.20**	**39.20**
Illinois	24	12,351	2.84	2.30	8.62	210.00	51.87
Gallatin	24	12,351	2.84	2.30	8.62	210.00	51.87
Kentucky	*	12,390	1.96	1.58	10.55	226.60	56.15
Union	*	12,390	1.96	1.58	10.55	226.60	56.15
Missouri	80	10,851	2.71	2.50	12.94	162.11	35.18
Bates	80	10,851	2.71	2.50	12.94	162.11	35.18
Oklahoma	4	12,442	2.68	2.16	11.16	162.36	40.40
Le Flore	2	12,412	1.95	1.57	12.12	160.10	39.74
Nowata	2	12,469	3.35	2.69	10.30	164.40	41.00
Indiana Michigan Power Co Tanners Creek	**2,455**	**11,749**	**1.35**	**1.15**	**9.80**	**115.86**	**27.23**
Kentucky	367	12,129	.68	.56	11.18	135.05	32.76
Boyd	32	11,941	.68	.57	11.44	106.36	25.40
Knott	36	12,303	.70	.57	11.21	216.32	53.23
Magoffin	36	12,303	.70	.57	11.21	216.32	53.23
Martin	15	11,635	.62	.53	11.37	113.89	26.50
Pike	246	12,134	.67	.55	11.12	115.72	28.08
Unknown[1]	*	11,677	.66	.57	9.50	113.50	26.51
Pennsylvania	65	12,957	2.50	1.93	7.94	104.03	26.96
Greene	65	12,957	2.50	1.93	7.94	104.03	26.96
West Virginia	1,677	12,204	1.69	1.38	10.73	109.53	26.74
Boone	286	12,160	.68	.56	11.27	115.37	28.06
Clay	33	12,628	.69	.55	10.92	143.65	36.28
Kanawha	133	12,144	.68	.56	12.43	123.77	30.06
Logan	111	12,251	.70	.57	11.42	112.63	27.60
Marshall	845	12,222	2.69	2.20	10.13	95.67	23.39
Mingo	147	11,796	.63	.54	10.88	127.90	30.17
Nicholas	112	12,618	.69	.54	10.91	142.20	35.88
Wayne	5	11,989	.69	.58	10.94	144.91	34.75
Unknown[1]	4	12,523	.67	.54	10.80	129.07	32.33
Wyoming	346	8,915	.20	.22	4.18	133.44	23.79
Campbell	346	8,915	.20	.22	4.18	133.44	23.79
Indiana Michigan Power Co Rockport	**9,449**	**9,130**	**.32**	**.35**	**5.26**	**117.92**	**21.53**
Colorado	168	12,074	.45	.37	8.71	146.58	35.40
Delta	158	12,062	.45	.37	8.80	146.70	35.39
Gunnison	10	12,260	.52	.42	7.40	144.80	35.50

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Indiana Michigan Power Co Rockport							
Indiana	196	11,570	1.16	1.00	4.73	151.71	35.11
Pike	196	11,570	1.16	1.00	4.73	151.71	35.11
Kentucky	390	11,210	.68	.60	10.71	149.38	33.49
Boyd	8	12,156	.70	.58	10.90	110.40	26.84
Clinton	32	12,013	.86	.71	11.24	123.02	29.56
Floyd	55	8,416	.33	.39	5.80	137.61	23.16
Lawrence	112	11,821	.83	.70	12.19	100.57	23.78
Martin	19	11,352	.88	.77	14.63	130.19	29.56
Morgan	1	11,856	.88	.74	12.80	185.50	43.99
Pike	163	11,510	.63	.55	10.77	196.51	45.24
Ohio	19	12,007	.84	.70	12.51	181.67	43.63
Mahoning	19	12,007	.84	.70	12.51	181.67	43.63
West Virginia	258	12,017	.84	.70	11.69	129.48	31.12
Boone	59	12,176	.78	.64	11.02	138.06	33.62
Kanawha	38	12,134	.88	.72	11.79	142.41	34.56
Mingo	60	11,801	.86	.73	12.43	126.12	29.77
Wayne	101	12,010	.85	.71	11.59	121.43	29.17
Wyoming	8,208	8,755	.26	.30	4.56	110.31	19.32
Campbell	8,208	8,755	.26	.30	4.56	110.31	19.32
Imported	210	11,456	.52	.45	11.43	211.08	48.36
Imported Coal	210	11,456	.52	.45	11.43	211.08	48.36
Indiana-Kentucky Electric Corp Clifty Creek	**3,862**	**10,195**	**.57**	**.56**	**5.46**	**123.17**	**25.11**
Kentucky	14	12,734	1.69	1.33	10.93	139.94	35.64
Pike	14	12,734	1.69	1.33	10.93	139.94	35.64
Ohio	221	10,954	4.01	3.66	12.91	115.33	25.27
Jackson	221	10,954	4.01	3.66	12.91	115.33	25.27
Virginia	928	13,800	.75	.54	5.65	156.19	43.11
Buchanan	901	13,842	.72	.52	5.42	156.62	43.36
Wise	27	12,424	1.93	1.55	13.27	140.08	34.81
Wyoming	2,698	8,880	.22	.25	4.76	106.19	18.86
Campbell	1,369	8,940	.21	.23	4.30	108.81	19.46
Converse	1,329	8,819	.24	.27	5.22	103.46	18.25
Indianapolis Power & Light Co Stout	**1,232**	**10,889**	**1.17**	**1.07**	**8.95**	**111.48**	**24.28**
Indiana	1,232	10,889	1.17	1.07	8.95	111.48	24.28
Daviess	5	11,463	1.87	1.63	6.80	119.40	27.37
Greene	152	11,133	1.20	1.08	8.20	115.27	25.67
Sullivan	246	10,910	1.22	1.12	9.21	115.09	25.11
Vigo	829	10,834	1.14	1.05	9.03	109.64	23.76
Indianapolis Power & Light Co Petersburg	**2,157**	**11,197**	**2.77**	**2.47**	**9.07**	**85.27**	**19.10**
Indiana	2,157	11,197	2.77	2.47	9.07	85.27	19.10
Daviess	432	11,479	2.62	2.28	7.77	84.16	19.32
Dubois	7	9,428	1.16	1.23	15.97	112.12	21.14
Gibson	1,263	11,092	2.80	2.52	9.53	85.22	18.90
Greene	34	11,377	1.25	1.10	6.10	120.80	27.49
Knox	356	11,279	3.08	2.73	8.98	82.59	18.63
Pike	65	11,015	2.58	2.34	9.90	87.40	19.25
Indianapolis Power & Light Co Pritchard	**791**	**11,293**	**1.21**	**1.07**	**7.21**	**109.53**	**24.74**
Indiana	791	11,293	1.21	1.07	7.21	109.53	24.74
Daviess	161	11,421	1.29	1.13	7.15	116.40	26.59
Greene	594	11,282	1.19	1.05	7.11	107.77	24.32
Sullivan	10	10,735	1.11	1.03	8.89	103.89	22.30
Vigo	26	10,985	1.12	1.02	9.19	108.80	23.90
Interstate Power Co Dubuque	**204**	**11,690**	**.57**	**.48**	**7.11**	**144.98**	**33.90**
Colorado	171	11,820	.51	.43	7.51	143.44	33.91
Delta	21	12,195	.36	.29	6.98	141.14	34.43
Mesa	119	12,119	.58	.48	8.06	146.50	35.51
Moffat	31	10,421	.34	.32	5.77	131.61	27.43
Illinois	10	11,888	1.34	1.13	5.48	176.09	41.87
Jackson	10	11,888	1.34	1.13	5.48	176.09	41.87

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Interstate Power Co Dubuque							
Indiana	16	11,569	0.85	0.73	4.43	173.70	40.19
Pike	16	11,569	.85	.73	4.43	173.70	40.19
Wyoming	7	8,423	.32	.38	5.52	47.10	7.93
Campbell	7	8,423	.32	.38	5.52	47.10	7.93
Interstate Power Co Lansing	**812**	**8,708**	**.31**	**.35**	**5.56**	**81.62**	**14.21**
Colorado	10	11,978	.54	.45	8.33	152.60	36.56
Mesa	10	11,978	.54	.45	8.33	152.60	36.56
Wyoming	801	8,666	.31	.35	5.52	80.37	13.93
Campbell	801	8,666	.31	.35	5.52	80.37	13.93
Interstate Power Co Kapp	**669**	**8,736**	**.30**	**.34**	**5.52**	**68.76**	**12.01**
Wyoming	669	8,736	.30	.34	5.52	68.76	12.01
Campbell	669	8,736	.30	.34	5.52	68.76	12.01
Iowa-Illinois Gas&Electric Co Riverside	**433**	**8,641**	**.31**	**.36**	**5.27**	**82.23**	**14.21**
Wyoming	433	8,641	.31	.36	5.27	82.23	14.21
Campbell	433	8,641	.31	.36	5.27	82.23	14.21
Iowa-Illinois Gas&Electric Co Louisa	**2,760**	**8,481**	**.30**	**.35**	**5.19**	**92.28**	**15.65**
Wyoming	2,760	8,481	.30	.35	5.19	92.28	15.65
Campbell	2,760	8,481	.30	.35	5.19	92.28	15.65
Jacksonville Electric Auth Northside	**38**	**12,114**	**2.37**	**1.96**	**10.08**	**231.10**	**55.99**
Pennsylvania	38	12,114	2.37	1.96	10.08	231.10	55.99
Greene	38	12,114	2.37	1.96	10.08	231.10	55.99
Jacksonville Electric Auth St. Johns River	**3,436**	**12,197**	**.97**	**.80**	**11.02**	**159.65**	**38.95**
Kentucky	1,044	12,574	1.34	1.06	17.79	165.53	41.63
Harlan	749	12,649	1.34	1.06	20.00	164.08	41.51
Pike	295	12,382	1.34	1.08	12.16	169.31	41.93
Pennsylvania	334	13,079	1.84	1.40	7.12	143.50	37.54
Greene	334	13,079	1.84	1.40	7.12	143.50	37.54
West Virginia	182	12,090	.87	.72	13.67	167.83	40.58
Kanawha	182	12,090	.87	.72	13.67	167.83	40.58
Imported	1,876	11,841	.62	.53	7.69	158.55	37.55
Imported Coal	1,876	11,841	.62	.53	7.69	158.55	37.55
Jamestown City of Samuel A Carlson	**76**	**12,573**	**1.82**	**1.45**	**10.75**	**144.20**	**36.26**
Pennsylvania	76	12,573	1.82	1.45	10.75	144.20	36.26
Armstrong	12	12,778	1.57	1.23	10.50	148.18	37.87
Clarion	2	13,148	1.25	.95	8.67	187.78	49.38
Clearfield	2	12,505	1.66	1.32	10.61	181.35	45.36
Elk	30	12,448	1.98	1.59	10.28	139.28	34.67
Jefferson	30	12,586	1.81	1.44	11.48	141.66	35.66
Kansas City City of Quindaro	**503**	**8,810**	**.29**	**.33**	**5.37**	**97.18**	**17.12**
Wyoming	503	8,810	.29	.33	5.37	97.18	17.12
Campbell	503	8,810	.29	.33	5.37	97.18	17.12
Kansas City City of Nearman	**1,069**	**8,045**	**.39**	**.48**	**5.14**	**71.80**	**11.55**
Wyoming	1,069	8,045	.39	.48	5.14	71.80	11.55
Campbell	1,069	8,045	.39	.48	5.14	71.80	11.55
Kansas City Power & Light Co Hawthorne	**841**	**8,713**	**.30**	**.35**	**5.36**	**109.65**	**19.11**
Wyoming	841	8,713	.30	.35	5.36	109.65	19.11
Campbell	841	8,713	.30	.35	5.36	109.65	19.11
Kansas City Power & Light Co Iatan	**2,494**	**8,757**	**.30**	**.34**	**5.63**	**70.20**	**12.29**
Wyoming	2,494	8,757	.30	.34	5.63	70.20	12.29
Campbell	2,494	8,757	.30	.34	5.63	70.20	12.29
Kansas City Power & Light Co La Cygne	**4,259**	**8,871**	**.67**	**.75**	**6.54**	**77.83**	**13.81**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Kansas City Power & Light Co La Cygne							
Colorado	15	10,427	3.27	3.14	20.10	129.80	27.07
Routt	15	10,427	3.27	3.14	20.10	129.80	27.07
Kansas	160	10,573	3.73	3.53	20.10	120.27	25.43
Linn	152	10,573	3.75	3.54	20.11	120.56	25.49
Unknown[1]	8	10,564	3.47	3.28	19.80	114.80	24.25
Missouri	167	10,983	5.61	5.11	18.32	117.06	25.71
Audrain	19	10,921	5.68	5.20	18.60	123.90	27.06
Bates	131	10,985	5.52	5.03	18.31	116.59	25.61
Unknown[1]	17	11,042	6.20	5.61	18.10	113.10	24.98
Wyoming	3,917	8,705	.32	.37	5.43	73.38	12.78
Campbell	3,917	8,705	.32	.37	5.43	73.38	12.78
Kansas City Power & Light Co Montrose	**1,851**	**8,784**	**.38**	**.44**	**5.21**	**87.38**	**15.35**
Wyoming	1,851	8,784	.38	.44	5.21	87.38	15.35
Campbell	1,851	8,784	.38	.44	5.21	87.38	15.35
Kansas Power & Light Co Lawrence	**1,934**	**9,870**	**.37**	**.38**	**7.00**	**136.41**	**26.93**
Colorado	938	11,058	.44	.40	8.42	155.05	34.29
Moffat	345	10,586	.35	.33	5.77	151.75	32.13
Routt	593	11,332	.50	.44	9.97	156.85	35.55
Montana	143	8,775	.31	.35	5.50	106.84	18.75
Big Horn	143	8,775	.31	.35	5.50	106.84	18.75
Wyoming	853	8,747	.30	.35	5.68	115.47	20.20
Campbell	853	8,747	.30	.35	5.68	115.47	20.20
Kansas Power & Light Co Jeffrey Energy	**11,178**	**8,407**	**.37**	**.44**	**4.87**	**110.13**	**18.52**
Wyoming	11,178	8,407	.37	.44	4.87	110.13	18.52
Campbell	11,178	8,407	.37	.44	4.87	110.13	18.52
Kansas Power & Light Co Tecumseh	**830**	**9,722**	**.36**	**.37**	**6.84**	**129.90**	**25.26**
Colorado	367	10,960	.43	.39	8.29	151.27	33.16
Moffat	157	10,507	.35	.33	5.85	148.17	31.13
Routt	210	11,298	.50	.44	10.11	153.43	34.67
Montana	57	8,767	.31	.35	5.51	103.72	18.19
Big Horn	57	8,767	.31	.35	5.51	103.72	18.19
Wyoming	406	8,738	.30	.35	5.71	109.37	19.11
Campbell	406	8,738	.30	.35	5.71	109.37	19.11
Kentucky Power Co Big Sandy	**3,236**	**11,990**	**.92**	**.77**	**10.54**	**102.76**	**24.64**
Kentucky	3,048	11,990	.93	.77	10.47	96.71	23.19
Boyd	710	11,740	.86	.74	11.67	90.13	21.16
Floyd	51	11,644	1.06	.91	14.41	113.35	26.40
Johnson	850	12,158	1.04	.86	9.55	105.81	25.73
Lawrence	1,270	12,032	.89	.74	10.03	92.84	22.34
Martin	167	11,981	.84	.70	12.17	101.87	24.41
West Virginia	187	12,002	.87	.73	11.65	200.95	48.23
Lincoln	*	12,156	.79	.65	10.20	98.90	24.04
Mingo	93	12,000	.87	.73	11.67	202.01	48.48
Wayne	94	12,002	.87	.73	11.64	200.35	48.09
Kentucky Utilities Co Green River	**454**	**11,566**	**2.04**	**1.76**	**11.57**	**122.48**	**28.33**
Kentucky	413	11,545	2.16	1.87	11.47	119.64	27.62
Hopkins	3	10,371	1.84	1.77	14.80	125.10	25.95
Morgan	137	11,548	2.19	1.89	10.59	100.22	23.15
Muhlenberg	184	11,216	2.22	1.98	12.45	122.99	27.59
Webster	89	12,264	1.99	1.62	10.68	141.28	34.65
West Virginia	41	11,780	.86	.73	12.57	150.46	35.45
Wayne	41	11,780	.86	.73	12.57	150.46	35.45
Kentucky Utilities Co Brown	**1,558**	**12,024**	**1.55**	**1.29**	**12.68**	**127.42**	**30.64**
Kentucky	1,550	12,024	1.56	1.30	12.67	127.02	30.55
Floyd	57	12,412	1.64	1.32	11.35	134.85	33.48
Knott	44	12,225	1.29	1.05	11.19	175.19	42.83
Leslie	326	12,098	1.61	1.33	11.97	124.70	30.17
Letcher	3	12,236	1.15	.94	10.10	164.60	40.28
Perry	1,119	11,974	1.55	1.30	13.01	125.24	29.99

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Kentucky Utilities Co Brown							
West Virginia	8	11,964	0.78	0.65	14.50	200.70	48.02
Logan	8	11,964	.78	.65	14.50	200.70	48.02
Kentucky Utilities Co Ghent	**5,413**	**11,344**	**1.35**	**1.19**	**10.82**	**115.58**	**26.22**
Kentucky	422	11,706	1.58	1.35	12.54	103.61	24.26
Boyd	33	11,833	.63	.53	10.61	150.05	35.51
Carter	10	12,190	.76	.62	11.60	120.30	29.33
Harlan	2	11,756	.59	.50	15.90	193.50	45.50
Jackson	22	12,557	3.90	3.11	12.50	171.40	43.05
Knott	9	11,755	.92	.78	11.13	115.02	27.04
Magoffin	176	11,553	2.46	2.13	13.74	78.59	18.16
Perry	1	10,716	1.73	1.61	11.60	89.40	19.16
Pike	170	11,708	.63	.54	11.77	108.46	25.40
West Virginia	3,813	12,112	1.65	1.36	12.11	117.96	28.58
Boone	689	12,393	.65	.53	11.41	139.30	34.53
Clay	349	12,121	.69	.57	12.46	119.88	29.06
Kanawha	793	12,110	.69	.57	12.18	112.00	27.12
Logan	302	12,108	.67	.55	12.89	177.34	42.95
Marshall	1,233	11,966	3.67	3.07	12.54	85.73	20.52
Mason	70	13,080	.75	.57	8.03	144.95	37.92
Mingo	81	11,934	.67	.56	10.60	125.51	29.96
Wayne	242	11,757	.72	.61	12.57	122.28	28.75
Unknown[1]	54	12,491	.64	.51	8.90	237.40	59.31
Wyoming	1,178	8,727	.30	.35	6.03	110.65	19.31
Campbell	1,131	8,728	.30	.35	6.03	110.70	19.32
Converse	47	8,717	.28	.32	6.00	109.40	19.07
Kentucky Utilities Co Tyrone	**133**	**13,039**	**.80**	**.61**	**7.90**	**121.50**	**31.68**
Kentucky	133	13,039	.80	.61	7.90	121.50	31.68
Knott	22	13,161	.83	.63	7.93	119.35	31.41
Perry	110	13,014	.79	.61	7.89	121.93	31.74
Lakeland City of Plant 3-Mcintosh	**330**	**12,495**	**1.10**	**.88**	**9.12**	**186.57**	**46.62**
Kentucky	226	12,781	1.21	.95	9.10	172.20	44.02
Harlan	146	12,710	1.27	1.00	9.42	163.72	41.62
Knott	49	13,095	1.08	.83	7.74	163.16	42.73
Pike	31	12,617	1.15	.91	9.77	227.24	57.34
Virginia	29	12,827	1.53	1.19	10.92	229.28	58.82
Dickenson	29	12,827	1.53	1.19	10.92	229.28	58.82
Imported	75	11,504	.61	.53	8.50	216.29	49.77
Imported Coal	75	11,504	.61	.53	8.50	216.29	49.77
Lansing City of Eckert	**1,046**	**9,016**	**.34**	**.38**	**5.88**	**120.24**	**21.68**
Kentucky	65	12,818	.95	.74	9.02	164.88	42.27
Harlan	28	13,133	.90	.69	7.64	170.49	44.78
Pike	36	12,574	.98	.78	10.09	160.33	40.32
Utah	1	12,630	.89	.70	7.61	199.76	50.46
Carbon	1	12,630	.89	.70	7.61	199.76	50.46
Wyoming	980	8,759	.30	.34	5.67	115.75	20.28
Campbell	980	8,759	.30	.34	5.67	115.75	20.28
Lansing City of Erickson	**318**	**12,588**	**.92**	**.73**	**9.56**	**168.71**	**42.47**
Colorado	11	12,056	.35	.29	7.08	182.24	43.94
Gunnison	11	12,056	.35	.29	7.08	182.24	43.94
Kentucky	297	12,621	.94	.75	9.72	167.46	42.27
Harlan	89	12,983	.93	.72	7.33	180.22	46.80
Pike	208	12,465	.95	.76	10.75	161.75	40.32
Utah	8	12,630	.89	.70	7.61	199.76	50.46
Carbon	8	12,630	.89	.70	7.61	199.76	50.46
Wyoming	1	8,761	.29	.33	5.76	115.50	20.24
Campbell	1	8,761	.29	.33	5.76	115.50	20.24
Los Angeles City of Intermountain	**5,350**	**11,819**	**.51**	**.44**	**8.97**	**136.41**	**32.24**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Los Angeles City of Intermountain							
Utah	5,350	11,819	0.51	0.44	8.97	136.41	32.24
Carbon	3,863	11,701	.54	.46	9.52	141.70	33.16
Emery	1,487	12,123	.44	.36	7.54	123.16	29.86
Louisville Gas & Electric Co Cane Run	**1,604**	**11,332**	**3.51**	**3.10**	**11.46**	**95.58**	**21.66**
Indiana	956	11,314	3.56	3.15	10.42	95.76	21.67
Pike	956	11,314	3.56	3.15	10.42	95.76	21.67
Kentucky	648	11,359	3.44	3.03	12.98	95.33	21.66
Hopkins	626	11,349	3.44	3.03	12.95	95.23	21.61
Webster	22	11,629	3.51	3.02	13.87	98.16	22.83
Louisville Gas & Electric Co Mill Creek	**4,457**	**11,321**	**3.14**	**2.77**	**12.41**	**93.87**	**21.25**
Illinois	44	12,325	3.45	2.80	11.29	116.06	28.61
Gallatin	43	12,329	3.47	2.81	11.36	115.28	28.43
Saline	1	12,221	2.77	2.27	9.20	140.20	34.27
Kentucky	3,746	11,169	3.16	2.83	12.59	94.21	21.04
Henderson	988	10,765	3.13	2.91	11.39	92.14	19.84
Hopkins	1,684	11,431	3.46	3.03	12.83	94.05	21.50
Johnson	107	9,366	1.44	1.54	28.14	72.76	13.63
Mclean	117	10,710	3.04	2.83	11.31	142.02	30.42
Magoffin	243	11,632	2.36	2.03	13.24	88.86	20.67
Muhlenberg	496	11,276	3.03	2.69	10.84	90.35	20.38
Pike	15	12,096	1.19	.98	10.20	193.00	46.69
Webster	96	11,419	3.30	2.89	12.80	98.79	22.56
West Virginia	667	12,109	2.99	2.47	11.47	90.59	21.94
Boone	7	12,767	.73	.57	7.90	164.60	42.03
Marshall	604	12,113	3.21	2.65	11.47	86.37	20.92
Wayne	56	11,987	.85	.71	11.88	127.03	30.46
Louisville Gas & Electric Co Trimble County	**1,641**	**11,667**	**3.83**	**3.29**	**14.16**	**89.16**	**20.80**
Kentucky	142	10,389	2.57	2.47	18.64	102.52	21.30
Henderson	42	10,594	3.20	3.02	12.80	94.51	20.02
Johnson	40	9,674	1.49	1.54	29.26	70.12	13.57
Mclean	3	10,611	2.83	2.67	11.90	133.80	28.40
Muhlenberg	43	10,325	3.44	3.34	17.22	101.37	20.93
Pike	14	11,927	1.06	.89	11.80	193.90	46.25
West Virginia	1,499	11,788	3.95	3.36	13.74	88.05	20.76
Cabell	136	10,392	3.57	3.43	16.02	110.68	23.00
Marshall	1,363	11,927	3.99	3.35	13.51	86.08	20.53
Lower Colorado River Authority S Seymour-Fayette	**6,426**	**8,475**	**.33**	**.39**	**8.44**	**90.73**	**15.38**
Wyoming	6,426	8,475	.33	.39	8.44	90.73	15.38
Campbell	6,426	8,475	.33	.39	8.44	90.73	15.38
Madison Gas & Electric Co Blount	**199**	**11,019**	**1.51**	**1.37**	**9.10**	**152.70**	**33.65**
Illinois	11	12,108	1.29	1.07	5.84	221.29	53.59
Jackson	3	11,882	1.30	1.10	5.27	199.46	47.40
Saline	8	12,192	1.29	1.06	6.05	229.27	55.91
Indiana	182	10,918	1.52	1.39	9.21	146.04	31.89
Sullivan	182	10,918	1.52	1.39	9.21	146.04	31.89
Kentucky	6	12,091	1.69	1.39	11.67	209.31	50.62
Union	6	12,091	1.69	1.39	11.67	209.31	50.62
Manitowoc Public Utilities Manitowoc	**158**	**12,724**	**1.44**	**1.13**	**7.56**	**172.30**	**43.85**
Colorado	15	12,116	.62	.51	8.00	157.80	38.24
Gunnison	15	12,116	.62	.51	8.00	157.80	38.24
Indiana	19	10,922	.82	.75	8.67	161.33	35.24
Sullivan	19	10,922	.82	.75	8.67	161.33	35.24
Kentucky	39	13,148	1.68	1.28	8.11	252.85	66.49
Knott	13	13,426	1.72	1.28	7.48	280.91	75.43
Pike	27	13,018	1.66	1.27	8.40	239.25	62.29
Pennsylvania	84	13,037	1.59	1.22	6.98	138.69	36.16
Greene	84	13,037	1.59	1.22	6.98	138.69	36.16

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Manitowoc Public Utilities Manitowoc							
West Virginia	1	13,290	2.36	1.78	6.70	159.85	42.49
Monongalia	1	13,290	2.36	1.78	6.70	159.85	42.49
Marquette City of Shiras	**193**	**9,817**	**.40**	**.40**	**4.54**	**138.80**	**27.25**
Kentucky	25	13,247	.83	.62	7.67	206.14	54.62
Perry	25	13,247	.83	.62	7.67	206.14	54.62
Montana	169	9,319	.33	.36	4.09	124.90	23.28
Big Horn	169	9,319	.33	.36	4.09	124.90	23.28
Michigan South Central Pwr Agy Endicott	**173**	**11,953**	**2.72**	**2.28**	**11.77**	**169.45**	**40.51**
Ohio	152	11,837	2.88	2.44	12.35	171.41	40.58
Columbiana	59	11,983	2.44	2.04	10.87	177.04	42.43
Harrison	93	11,745	3.16	2.69	13.28	167.80	39.42
Pennsylvania	21	12,775	1.57	1.23	7.67	156.53	39.99
Washington	21	12,775	1.57	1.23	7.67	156.53	39.99
Midwest Power Council Bluffs	**3,668**	**8,570**	**.31**	**.36**	**5.26**	**60.36**	**10.35**
Wyoming	3,668	8,570	.31	.36	5.26	60.36	10.35
Campbell	3,668	8,570	.31	.36	5.26	60.36	10.35
Midwest Power George Neal 1/4	**6,746**	**8,669**	**.35**	**.41**	**5.02**	**75.41**	**13.07**
Colorado	25	10,371	.27	.26	5.91	142.75	29.61
Moffat	25	10,371	.27	.26	5.91	142.75	29.61
Utah	24	11,267	.48	.42	9.12	130.37	29.38
Sevier	24	11,267	.48	.42	9.12	130.37	29.38
Wyoming	6,696	8,653	.35	.41	5.00	74.85	12.95
Campbell	6,473	8,598	.35	.41	4.96	73.66	12.67
Carbon	184	10,544	.44	.41	6.28	109.32	23.05
Converse	40	8,828	.27	.31	5.28	72.14	12.74
Minnesota Power & Light Co Boswell Energy Cen	**3,837**	**9,017**	**.58**	**.64**	**6.91**	**117.34**	**21.16**
Montana	3,837	9,017	.58	.64	6.91	117.34	21.16
Big Horn	1,483	9,420	.36	.38	4.28	104.91	19.76
Rosebud	2,354	8,764	.72	.82	8.57	125.76	22.04
Minnesota Power & Light Co Laskin Energy Cen	**431**	**9,368**	**.37**	**.39**	**4.38**	**121.02**	**22.67**
Montana	431	9,368	.37	.39	4.38	121.02	22.67
Big Horn	431	9,368	.37	.39	4.38	121.02	22.67
Minnkota Power Coop Inc Young	**3,972**	**6,667**	**.87**	**1.30**	**8.28**	**71.41**	**9.52**
North Dakota	3,972	6,667	.87	1.30	8.28	71.41	9.52
Oliver	3,972	6,667	.87	1.30	8.28	71.41	9.52
Mississippi Power Co Daniel	**2,883**	**11,586**	**.52**	**.45**	**9.21**	**172.46**	**39.96**
Alabama	10	12,621	.70	.55	9.90	182.10	45.97
Tuscaloosa	10	12,621	.70	.55	9.90	182.10	45.97
Colorado	2,504	11,657	.53	.45	9.41	166.36	38.79
Gunnison	1,487	11,923	.55	.46	8.83	157.12	37.47
Routt	1,017	11,269	.50	.44	10.26	180.66	40.72
Wyoming	54	8,768	.29	.33	5.70	146.20	25.64
Campbell	54	8,768	.29	.33	5.70	146.20	25.64
Imported	315	11,472	.50	.43	8.24	224.84	51.59
Imported Coal	315	11,472	.50	.43	8.24	224.84	51.59
Mississippi Power Co Watson	**2,213**	**11,630**	**.80**	**.69**	**7.06**	**157.13**	**36.55**
Colorado	232	11,958	.59	.50	9.13	159.02	38.03
Gunnison	232	11,958	.59	.50	9.13	159.02	38.03
Illinois	401	12,071	1.42	1.18	6.42	153.48	37.05
Gallatin	13	12,680	2.68	2.12	7.88	143.31	36.34
Saline	388	12,051	1.38	1.15	6.37	153.83	37.08
Imported	1,580	11,470	.68	.59	6.92	157.82	36.20
Imported Coal	1,580	11,470	.68	.59	6.92	157.82	36.20
Monongahela Power Co Albright	**419**	**12,509**	**1.61**	**1.29**	**11.80**	**105.80**	**26.47**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Monongahela Power Co Albright							
West Virginia	419	12,509	1.61	1.29	11.80	105.80	26.47
Barbour	15	12,102	1.63	1.35	13.69	102.17	24.73
Mineral	1	11,654	.86	.74	12.71	102.97	24.00
Monongalia	111	11,984	1.61	1.34	13.60	103.47	24.80
Preston	293	12,731	1.61	1.27	11.02	106.81	27.20
Monongahela Power Co Ft Martin	**556**	**12,469**	**1.60**	**1.29**	**11.18**	**106.51**	**26.56**
Pennsylvania	427	12,558	1.58	1.26	10.83	108.12	27.16
Greene	427	12,558	1.58	1.26	10.83	108.12	27.16
West Virginia	128	12,173	1.68	1.38	12.34	101.00	24.59
Marion	*	12,394	1.53	1.23	11.50	108.30	26.85
Monongalia	128	12,173	1.68	1.38	12.34	100.97	24.58
Monongahela Power Co Harrison	**1,126**	**12,271**	**3.35**	**2.73**	**12.47**	**120.45**	**29.56**
Ohio	28	12,578	3.89	3.10	8.78	143.87	36.19
Belmont	28	12,578	3.89	3.10	8.78	143.87	36.19
Pennsylvania	6	12,174	2.26	1.86	13.20	123.57	30.09
Greene	6	12,174	2.26	1.86	13.20	123.57	30.09
West Virginia	1,091	12,263	3.34	2.73	12.56	119.81	29.39
Harrison	1,028	12,252	3.35	2.73	12.55	121.26	29.71
Monongalia	7	13,120	2.34	1.78	8.17	142.03	37.27
Upshur	56	12,367	3.38	2.73	13.34	90.84	22.47
Monongahela Power Co Pleasants	**718**	**12,228**	**3.76**	**3.08**	**10.87**	**91.19**	**22.30**
Ohio	324	12,340	4.05	3.28	9.81	88.28	21.79
Belmont	307	12,390	3.99	3.22	9.47	88.85	22.02
Noble	16	11,383	5.04	4.43	16.20	76.66	17.45
West Virginia	394	12,137	3.53	2.91	11.74	93.62	22.72
Marshall	394	12,137	3.53	2.91	11.74	93.62	22.72
Monongahela Power Co Rivesville	**255**	**11,754**	**1.03**	**.87**	**12.71**	**121.35**	**28.53**
Pennsylvania	73	11,790	1.05	.89	11.45	132.13	31.16
Fayette	73	11,790	1.05	.89	11.45	132.13	31.16
West Virginia	182	11,740	1.02	.87	13.22	117.00	27.47
Monongalia	182	11,740	1.02	.87	13.22	117.00	27.47
Monongahela Power Co Willow Island	**488**	**13,012**	**1.46**	**1.12**	**7.59**	**112.47**	**29.27**
Kentucky	33	12,553	1.34	1.06	9.61	141.44	35.51
Knott	33	12,553	1.34	1.06	9.61	141.44	35.51
Pennsylvania	451	13,045	1.47	1.13	7.44	110.40	28.81
Greene	166	13,068	1.44	1.10	7.85	111.28	29.08
Washington	285	13,032	1.49	1.14	7.21	109.90	28.64
West Virginia	3	13,078	1.32	1.01	7.50	114.50	29.95
Monongalia	3	13,078	1.32	1.01	7.50	114.50	29.95
Montana-Dakota Utilities Co Coyote	**2,550**	**6,958**	**1.11**	**1.60**	**9.21**	**74.53**	**10.37**
North Dakota	2,550	6,958	1.11	1.60	9.21	74.53	10.37
Mercer	1,299	6,962	1.11	1.59	9.19	74.62	10.39
Oliver	1,251	6,953	1.12	1.61	9.24	74.43	10.35
Montana-Dakota Utilities Co Heskett	**561**	**7,069**	**.76**	**1.08**	**7.25**	**96.00**	**13.57**
North Dakota	561	7,069	.76	1.08	7.25	96.00	13.57
Mercer	357	7,065	.74	1.05	7.20	95.92	13.55
Oliver	203	7,076	.80	1.13	7.33	96.13	13.60
Montana-Dakota Utilities Co Lewis and Clark	**307**	**6,539**	**.53**	**.82**	**9.51**	**94.93**	**12.42**
Montana	307	6,539	.53	.82	9.51	94.93	12.42
Richland	307	6,539	.53	.82	9.51	94.93	12.42
Muscatine City of Muscatine	**951**	**8,278**	**.61**	**.73**	**6.30**	**87.73**	**14.53**
Wyoming	951	8,278	.61	.73	6.30	87.73	14.53
Campbell	951	8,278	.61	.73	6.30	87.73	14.53
Nebraska Public Power District Gerald Gentleman	**5,707**	**8,576**	**.30**	**.35**	**4.69**	**49.69**	**8.52**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Nebraska Public Power District Gerald Gentleman							
Wyoming	5,707	8,576	0.30	0.35	4.69	49.69	8.52
Campbell	5,707	8,576	.30	.35	4.69	49.69	8.52
Nebraska Public Power District Sheldon	**899**	**8,593**	**.32**	**.38**	**4.55**	**65.15**	**11.20**
Wyoming	899	8,593	.32	.38	4.55	65.15	11.20
Campbell	899	8,593	.32	.38	4.55	65.15	11.20
Nevada Power Co Gardner	**2,154**	**11,845**	**.59**	**.50**	**8.83**	**118.13**	**27.98**
Utah	2,154	11,845	.59	.50	8.83	118.13	27.98
Carbon	1,347	12,150	.69	.57	8.60	121.64	29.56
Sevier	806	11,335	.42	.37	9.21	111.84	25.35
Northern Indiana Pub Serv Co Bailly	**1,403**	**11,302**	**2.63**	**2.32**	**8.54**	**142.67**	**32.25**
Illinois	680	11,077	2.86	2.58	8.73	127.12	28.16
Perry	623	11,019	2.86	2.60	8.84	124.84	27.51
White	57	11,715	2.88	2.46	7.50	150.47	35.26
Indiana	589	11,257	2.45	2.18	8.43	164.02	36.93
Daviess	548	11,274	2.44	2.16	8.40	165.33	37.28
Sullivan	41	11,036	2.65	2.40	8.86	146.16	32.26
West Virginia	110	13,053	2.53	1.94	8.40	121.86	31.81
Monongalia	110	13,053	2.53	1.94	8.40	121.86	31.81
Wyoming	24	10,724	.58	.54	6.82	164.77	35.34
Campbell	1	8,860	.25	.28	4.87	101.14	17.92
Carbon	22	10,824	.60	.55	6.92	167.55	36.27
Northern Indiana Pub Serv Co Michigan City	**1,427**	**9,524**	**.38**	**.40**	**6.09**	**122.14**	**23.26**
Utah	228	12,200	.49	.40	9.01	159.04	38.81
Sevier	228	12,200	.49	.40	9.01	159.04	38.81
West Virginia	22	13,071	2.53	1.94	8.58	122.58	32.05
Monongalia	22	13,071	2.53	1.94	8.58	122.58	32.05
Wyoming	1,177	8,938	.32	.36	5.47	112.37	20.09
Campbell	1,081	8,795	.30	.34	5.37	107.38	18.89
Carbon	83	10,799	.61	.56	6.80	165.54	35.75
Converse	12	8,906	.26	.29	5.20	108.30	19.29
Northern Indiana Pub Serv Co Mitchell	**1,008**	**9,217**	**.29**	**.32**	**5.31**	**126.44**	**23.31**
Utah	45	11,595	.37	.32	8.33	193.00	44.76
Sevier	45	11,595	.37	.32	8.33	193.00	44.76
Wyoming	963	9,106	.29	.32	5.17	122.48	22.30
Campbell	831	8,860	.24	.27	4.90	112.56	19.95
Carbon	130	10,682	.60	.56	6.92	174.60	37.30
Converse	1	8,860	.22	.25	5.10	180.00	31.90
Northern Indiana Pub Serv Co Rollin Schahfer	**5,295**	**9,973**	**1.36**	**1.36**	**6.57**	**122.75**	**24.48**
Illinois	1,539	10,794	3.16	2.93	8.63	123.94	26.76
Logan	100	10,491	3.09	2.95	9.18	184.93	38.80
Montgomery	772	10,640	3.39	3.19	8.40	122.43	26.05
Perry	667	11,018	2.90	2.63	8.80	116.92	25.76
Virginia	137	14,083	.65	.46	4.89	179.93	50.68
Buchanan	137	14,083	.65	.46	4.89	179.93	50.68
West Virginia	470	13,098	2.38	1.82	8.23	117.26	30.72
Monongalia	470	13,098	2.38	1.82	8.23	117.26	30.72
Wyoming	3,149	8,926	.36	.40	5.39	119.31	21.30
Campbell	2,664	8,780	.35	.40	5.26	114.16	20.05
Carbon	235	10,688	.60	.56	7.01	170.36	36.42
Converse	249	8,830	.25	.28	5.32	115.75	20.44
Northern States Power Co Bay Front	**166**	**10,147**	**.30**	**.29**	**5.12**	**146.32**	**29.69**
Wyoming	166	10,147	.30	.29	5.12	146.32	29.69
Campbell	48	8,887	.20	.23	4.09	115.49	20.53
Carbon	66	11,293	.38	.34	5.70	160.00	36.14
Converse	53	9,861	.29	.29	5.34	151.94	29.97
Northern States Power Co Black Dog	**661**	**8,836**	**.20**	**.23**	**4.39**	**100.77**	**17.81**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Northern States Power Co Black Dog							
Wyoming	661	8,836	0.20	0.23	4.39	100.77	17.81
Campbell	661	8,836	.20	.23	4.39	100.77	17.81
Northern States Power Co High Bridge	**781**	**8,958**	**.20**	**.22**	**4.25**	**92.35**	**16.55**
Wyoming	781	8,958	.20	.22	4.25	92.35	16.55
Campbell	781	8,958	.20	.22	4.25	92.35	16.55
Northern States Power Co King	**1,742**	**8,903**	**.37**	**.41**	**5.68**	**102.59**	**18.27**
Montana	522	8,802	.67	.76	8.97	108.43	19.09
Big Horn	522	8,802	.67	.76	8.97	108.43	19.09
Wyoming	1,220	8,946	.24	.27	4.28	100.13	17.92
Campbell	1,220	8,946	.24	.27	4.28	100.13	17.92
Northern States Power Co Riverside	**1,310**	**8,964**	**.20**	**.22**	**4.20**	**94.16**	**16.88**
Wyoming	1,310	8,964	.20	.22	4.20	94.16	16.88
Campbell	1,310	8,964	.20	.22	4.20	94.16	16.88
Northern States Power Co Sherburne County	**8,595**	**8,750**	**.53**	**.60**	**7.64**	**91.62**	**16.03**
Montana	5,243	8,732	.67	.76	9.05	90.87	15.87
Big Horn	4,382	8,727	.66	.75	9.18	91.86	16.03
Rosebud	861	8,760	.72	.82	8.42	85.83	15.04
Wyoming	3,351	8,777	.31	.35	5.43	92.79	16.29
Campbell	3,351	8,777	.31	.35	5.43	92.79	16.29
Ohio Power Co Gavin	**7,226**	**11,564**	**3.39**	**2.93**	**11.30**	**153.61**	**35.53**
Kentucky	76	12,482	.85	.68	9.66	130.84	32.66
Pike	76	12,482	.85	.68	9.66	130.84	32.66
Ohio	6,480	11,461	3.56	3.10	11.43	159.50	36.56
Belmont	1,236	12,424	4.04	3.25	9.37	83.28	20.69
Gallia	322	10,936	2.70	2.47	12.81	102.16	22.34
Harrison	1	11,606	3.44	2.96	12.50	100.60	23.35
Jackson	322	10,936	2.70	2.47	12.81	102.16	22.34
Mahoning	8	11,787	1.04	.88	12.80	205.90	48.54
Meigs	4,260	11,301	3.62	3.20	11.71	196.45	44.40
Vinton	332	10,936	2.70	2.47	12.81	102.15	22.34
Pennsylvania	123	13,094	2.84	2.17	8.10	95.78	25.08
Greene	123	13,094	2.84	2.17	8.10	95.78	25.08
West Virginia	547	12,316	1.86	1.51	10.69	105.74	26.05
Boone	248	12,441	.79	.63	10.34	111.97	27.86
Brooke	183	12,302	3.75	3.05	10.75	89.23	21.95
Clay	3	12,408	.71	.57	11.90	147.20	36.53
Fayette	1	12,408	.71	.57	11.90	147.20	36.53
Kanawha	10	12,063	.80	.66	13.08	110.01	26.54
Marshall	21	12,533	2.69	2.15	8.92	94.39	23.66
Mingo	39	11,879	.81	.69	12.06	117.00	27.80
Wayne	43	12,004	.82	.68	11.41	131.88	31.66
Ohio Power Co Kammer	**1,523**	**13,008**	**1.46**	**1.12**	**7.56**	**112.14**	**29.17**
Kentucky	19	12,484	1.18	.95	10.60	111.20	27.76
Floyd	6	12,484	1.18	.95	10.60	111.20	27.76
Knott	6	12,484	1.18	.95	10.60	111.20	27.76
Magoffin	6	12,484	1.18	.95	10.60	111.20	27.76
Pennsylvania	1,479	13,022	1.48	1.14	7.57	111.94	29.15
Greene	1,453	13,021	1.48	1.14	7.57	111.88	29.14
Washington	26	13,070	1.45	1.11	7.26	115.19	30.11
Virginia	18	13,941	.62	.44	4.73	120.26	33.53
Tazewell	18	13,941	.62	.44	4.73	120.26	33.53
Wyoming	7	8,927	.23	.26	4.80	143.70	25.66
Campbell	7	8,927	.23	.26	4.80	143.70	25.66
Ohio Power Co Mitchell	**3,500**	**12,160**	**.80**	**.66**	**12.96**	**146.96**	**35.74**
Kentucky	2	11,478	.95	.83	13.30	172.90	39.69
Pike	2	11,478	.95	.83	13.30	172.90	39.69

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Ohio Power Co Mitchell							
West Virginia	3,499	12,160	0.80	0.66	12.96	146.95	35.74
Boone	2,273	12,080	.74	.61	12.97	151.83	36.68
Fayette	1	12,004	.74	.62	13.70	142.20	34.14
Kanawha	27	11,896	.83	.70	13.15	108.84	25.90
Mingo	4	11,893	.78	.65	12.99	121.25	28.84
Wayne	4	12,001	.81	.67	12.80	116.01	27.84
Webster	1,190	12,320	.92	.75	12.95	138.82	34.21
Ohio Power Co Muskingum	**3,348**	**11,839**	**2.28**	**1.93**	**11.54**	**131.82**	**31.21**
Ohio	1,795	11,511	3.52	3.05	11.59	130.92	30.14
Belmont	1	12,554	3.92	3.12	9.40	87.90	22.07
Morgan	13	11,635	3.19	2.74	10.60	94.56	22.00
Muskingum	352	11,642	3.08	2.65	10.50	127.75	29.75
Noble	561	11,442	3.77	3.29	12.21	131.79	30.16
Perry	867	11,499	3.53	3.07	11.65	132.29	30.42
West Virginia	1,553	12,219	.86	.71	11.49	132.79	32.45
Boone	899	12,157	.85	.70	10.99	131.04	31.86
Clay	*	12,376	.70	.57	12.40	145.20	35.94
Fayette	*	11,859	.75	.63	12.60	144.64	34.31
Logan	171	12,232	.72	.59	11.37	132.58	32.44
Webster	481	12,331	.95	.77	12.46	136.08	33.56
Ohio Valley Electric Corp Kyger Creek	**2,554**	**12,419**	**2.15**	**1.73**	**8.37**	**106.60**	**26.48**
Kentucky	210	12,552	.85	.67	9.25	120.80	30.33
Boyd	10	12,006	.81	.67	11.10	171.60	41.20
Pike	200	12,579	.85	.67	9.16	118.45	29.80
Ohio	528	12,329	3.78	3.07	9.40	85.35	21.04
Belmont	437	12,467	3.91	3.14	9.25	82.79	20.64
Harrison	21	12,230	2.79	2.28	11.00	96.00	23.48
Jackson	70	11,494	3.28	2.86	9.82	99.36	22.84
Pennsylvania	283	13,058	1.92	1.47	7.57	108.08	28.23
Greene	112	13,087	2.50	1.91	8.03	93.12	24.38
Washington	171	13,039	1.55	1.19	7.27	117.95	30.76
Virginia	454	13,802	.72	.52	5.64	128.36	35.43
Buchanan	454	13,802	.72	.52	5.64	128.36	35.43
West Virginia	870	12,429	2.74	2.20	9.95	99.26	24.67
Brooke	452	12,255	3.68	3.00	10.64	87.69	21.49
Greenbrier	21	13,075	1.06	.81	8.60	147.10	38.47
Kanawha	158	13,099	.69	.53	7.05	119.78	31.38
Marshall	169	12,180	3.14	2.58	11.28	93.47	22.77
Wayne	70	12,447	.82	.66	9.25	122.68	30.54
Wyoming	211	8,634	.33	.38	5.29	127.84	22.08
Big Horn	33	8,561	.30	.35	5.44	142.12	24.33
Campbell	114	8,683	.35	.40	5.18	124.61	21.64
Converse	63	8,584	.32	.37	5.43	126.26	21.68
Oklahoma Gas & Electric Co Muskogee	**5,166**	**8,768**	**.25**	**.29**	**5.10**	**78.39**	**13.75**
Wyoming	5,166	8,768	.25	.29	5.10	78.39	13.75
Campbell	4,211	8,758	.26	.29	5.06	78.77	13.80
Converse	955	8,812	.23	.26	5.27	76.74	13.52
Oklahoma Gas & Electric Co Sooner	**3,443**	**8,769**	**.25**	**.28**	**5.01**	**77.92**	**13.66**
Wyoming	3,443	8,769	.25	.28	5.01	77.92	13.66
Campbell	2,831	8,754	.25	.28	4.96	78.42	13.73
Converse	611	8,834	.25	.28	5.21	75.62	13.36
Omaha Public Power District Nebraska City	**2,975**	**8,472**	**.32**	**.38**	**5.46**	**55.35**	**9.38**
Wyoming	2,975	8,472	.32	.38	5.46	55.35	9.38
Campbell	2,975	8,472	.32	.38	5.46	55.35	9.38
Omaha Public Power District North Omaha	**2,263**	**8,643**	**.31**	**.35**	**5.64**	**61.08**	**10.56**
Wyoming	2,263	8,643	.31	.35	5.64	61.08	10.56
Campbell	2,263	8,643	.31	.35	5.64	61.08	10.56
Orlando Utilities Comm Stanton Energy	**2,544**	**12,723**	**1.20**	**.94**	**9.18**	**166.09**	**42.26**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Orlando Utilities Comm Stanton Energy							
Kentucky	2,544	12,723	1.20	0.94	9.18	166.09	42.26
Harlan	1,069	12,710	1.31	1.03	9.07	162.87	41.40
Letcher	909	12,694	.96	.76	9.69	170.04	43.17
Pike	567	12,796	1.37	1.07	8.56	165.86	42.45
Otter Tail Power Co Big Stone	**2,182**	**8,427**	**.33**	**.39**	**5.49**	**103.27**	**17.41**
Wyoming	2,182	8,427	.33	.39	5.49	103.27	17.41
Campbell	2,182	8,427	.33	.39	5.49	103.27	17.41
Otter Tail Power Co Hoot Lake	**511**	**9,247**	**.35**	**.38**	**4.23**	**125.70**	**23.25**
Montana	511	9,247	.35	.38	4.23	125.70	23.25
Big Horn	511	9,247	.35	.38	4.23	125.70	23.25
Owensboro City of Smith	**1,139**	**10,718**	**3.25**	**3.03**	**11.62**	**90.95**	**19.49**
Indiana	398	10,914	3.05	2.80	10.12	93.55	20.42
Daviess	23	10,823	2.29	2.12	10.90	98.10	21.23
Gibson	120	10,770	3.45	3.20	10.48	91.68	19.75
Pike	204	10,982	2.79	2.54	9.59	94.57	20.77
Warrick	50	11,026	3.53	3.20	11.06	91.69	20.22
Kentucky	741	10,612	3.36	3.17	12.43	89.51	19.00
Daviess	113	10,814	3.72	3.44	10.99	89.22	19.30
Henderson	347	10,411	3.46	3.32	12.49	88.12	18.35
Hopkins	13	9,279	2.32	2.50	12.32	81.94	15.21
Mclean	119	10,637	3.11	2.93	11.48	88.53	18.83
Ohio	54	10,587	2.19	2.07	12.10	92.58	19.60
Webster	96	11,265	3.67	3.25	15.30	94.82	21.36
PacifiCorp Carbon	**561**	**12,179**	**.48**	**.39**	**8.91**	**59.17**	**14.41**
Utah	561	12,179	.48	.39	8.91	59.17	14.41
Emery	561	12,179	.48	.39	8.91	59.17	14.41
PacifiCorp Emery-Hunter	**3,499**	**11,719**	**.54**	**.46**	**9.29**	**90.47**	**21.20**
Utah	3,499	11,719	.54	.46	9.29	90.47	21.20
Carbon	458	12,553	1.05	.84	7.75	75.84	19.04
Emery	1,852	11,778	.54	.46	10.10	106.30	25.04
Sevier	1,189	11,304	.35	.31	8.62	71.05	16.06
PacifiCorp Huntington	**2,271**	**12,004**	**.42**	**.35**	**8.34**	**69.72**	**16.74**
Utah	2,271	12,004	.42	.35	8.34	69.72	16.74
Carbon	14	12,833	1.20	.94	7.16	75.44	19.36
Emery	2,257	11,999	.42	.35	8.35	69.68	16.72
PacifiCorp Jim Bridger	**8,451**	**9,373**	**.53**	**.56**	**9.74**	**104.89**	**19.66**
Wyoming	8,451	9,373	.53	.56	9.74	104.89	19.66
Carbon	82	9,229	.42	.46	8.10	92.20	17.02
Sweetwater	8,369	9,375	.53	.57	9.75	105.01	19.69
PacifiCorp Johnston	**3,239**	**8,365**	**.35**	**.42**	**5.50**	**56.24**	**9.41**
Wyoming	3,239	8,365	.35	.42	5.50	56.24	9.41
Campbell	3,239	8,365	.35	.42	5.50	56.24	9.41
PacifiCorp Naughton	**2,266**	**9,883**	**.97**	**.98**	**5.07**	**96.60**	**19.09**
Wyoming	2,266	9,883	.97	.98	5.07	96.60	19.09
Lincoln	2,266	9,883	.97	.98	5.07	96.60	19.09
PacifiCorp Wyodak	**1,929**	**8,060**	**.60**	**.74**	**7.04**	**74.02**	**11.93**
Wyoming	1,929	8,060	.60	.74	7.04	74.02	11.93
Campbell	1,929	8,060	.60	.74	7.04	74.02	11.93
Painesville City of Painesville	**88**	**12,376**	**2.50**	**2.02**	**7.48**	**137.72**	**34.09**
Ohio	88	12,376	2.50	2.02	7.48	137.72	34.09
Columbiana	88	12,376	2.50	2.02	7.48	137.72	34.09
Philadelphia Electric Co Cromby	**13**	**12,782**	**2.28**	**1.78**	**9.35**	**163.65**	**41.84**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Philadelphia Electric Co Cromby							
Pennsylvania	13	12,782	2.28	1.78	9.35	163.65	41.84
Greene	7	13,157	2.46	1.87	8.07	139.99	36.84
Jefferson	3	11,881	2.49	2.10	13.36	237.94	56.54
Washington	3	12,811	1.64	1.28	8.35	151.43	38.80
Philadelphia Electric Co Eddystone	**195**	**13,127**	**1.89**	**1.44**	**8.02**	**154.77**	**40.63**
Pennsylvania	164	13,165	2.09	1.59	7.82	141.77	37.33
Greene	134	13,181	2.22	1.69	7.87	140.18	36.96
Washington	30	13,092	1.50	1.15	7.57	148.93	38.99
West Virginia	31	12,924	.80	.62	9.10	224.82	58.11
Nicholas	31	12,924	.80	.62	9.10	224.82	58.11
Plains Elec Gen&Trans Coop Inc Escalante	**533**	**9,159**	**.83**	**.91**	**18.41**	**135.12**	**24.75**
New Mexico	533	9,159	.83	.91	18.41	135.12	24.75
Mckinley	533	9,159	.83	.91	18.41	135.12	24.75
Platte River Power Authority Rawhide	**1,312**	**8,832**	**.23**	**.26**	**5.12**	**61.65**	**10.89**
Wyoming	1,312	8,832	.23	.26	5.12	61.65	10.89
Campbell	8	8,917	.21	.24	4.70	61.90	11.04
Converse	1,304	8,831	.23	.26	5.13	61.65	10.89
Portland General Electric Co Boardman	**2,583**	**8,706**	**.38**	**.43**	**6.21**	**110.99**	**19.33**
Utah	311	11,880	.54	.45	11.48	115.89	27.54
Emery	245	11,794	.55	.46	12.04	119.43	28.17
Sevier	66	12,202	.51	.42	9.40	103.20	25.18
Wyoming	2,272	8,272	.35	.43	5.49	110.03	18.20
Campbell	2,272	8,272	.35	.43	5.49	110.03	18.20
PSI Energy Inc Cayuga	**3,178**	**10,927**	**.95**	**.87**	**8.27**	**124.69**	**27.25**
Illinois	38	10,474	1.35	1.29	7.12	128.36	26.89
Vermilion	38	10,474	1.35	1.29	7.12	128.36	26.89
Indiana	3,140	10,932	.95	.87	8.28	124.65	27.25
Daviess	33	11,090	1.31	1.18	8.16	128.56	28.52
Knox	2,009	11,024	.82	.74	7.97	130.67	28.81
Parke	2	11,360	2.78	2.45	9.20	142.60	32.40
Vermillion	260	10,917	1.45	1.33	7.11	115.06	25.12
Vigo	451	10,374	1.05	1.02	10.93	106.85	22.17
White	386	11,100	1.09	.99	7.59	118.89	26.39
PSI Energy Inc Edwardsport	**351**	**11,135**	**1.47**	**1.32**	**8.52**	**108.51**	**24.17**
Indiana	351	11,135	1.47	1.32	8.52	108.51	24.17
Daviess	51	11,463	1.62	1.42	7.34	101.87	23.36
Knox	203	10,961	1.34	1.23	9.45	105.03	23.03
Pike	51	11,756	1.72	1.47	5.48	115.82	27.23
Vigo	46	10,853	1.60	1.48	9.08	123.11	26.72
PSI Energy Inc Gallagher	**1,259**	**12,092**	**1.91**	**1.58**	**7.59**	**127.73**	**30.89**
Illinois	194	12,329	2.06	1.67	7.62	145.34	35.84
Gallatin	101	12,591	2.63	2.09	8.66	132.86	33.46
Saline	93	12,046	1.44	1.20	6.49	159.46	38.42
Indiana	566	11,100	1.53	1.38	7.99	134.98	29.97
Clay	122	10,951	1.84	1.68	9.80	130.47	28.58
Daviess	14	11,274	1.51	1.34	7.63	140.88	31.77
Gibson	202	10,828	1.81	1.67	9.72	108.75	23.55
Knox	35	10,948	1.23	1.12	8.19	171.92	37.64
Pike	190	11,503	1.12	.97	4.99	157.01	36.12
Vigo	3	11,039	.58	.53	7.20	134.50	29.69
Kentucky	27	11,472	1.36	1.19	8.52	131.95	30.28
Unknown[1]	27	11,472	1.36	1.19	8.52	131.95	30.28
Pennsylvania	135	13,107	2.31	1.76	7.85	99.99	26.21
Greene	135	13,107	2.31	1.76	7.85	99.99	26.21
West Virginia	336	13,266	2.33	1.76	6.73	118.79	31.52
Kanawha	8	11,636	1.04	.89	12.38	163.33	38.01
Monongalia	327	13,308	2.37	1.78	6.59	117.79	31.35
PSI Energy Inc Gibson Station	**9,447**	**11,012**	**1.90**	**1.73**	**9.45**	**102.92**	**22.67**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
PSI Energy Inc Gibson Station							
Illinois	1,608	10,961	1.48	1.35	11.15	102.47	22.46
Saline	160	12,082	1.40	1.16	6.31	108.97	26.33
Wabash	1,449	10,838	1.49	1.37	11.68	101.67	22.04
Indiana	7,839	11,023	1.99	1.80	9.10	103.02	22.71
Gibson	7,343	10,995	2.05	1.87	9.31	101.57	22.33
Knox	69	10,959	.60	.55	7.86	132.14	28.96
Pike	293	11,711	1.02	.87	4.64	121.58	28.48
Vigo	99	10,725	1.19	1.11	8.89	122.09	26.19
Unknown[1]	35	12,065	1.46	1.21	6.43	129.20	31.18
PSI Energy Inc Noblesville	**185**	**10,508**	**1.55**	**1.48**	**8.72**	**145.36**	**30.55**
Indiana	185	10,508	1.55	1.48	8.72	145.36	30.55
Vigo	185	10,508	1.55	1.48	8.72	145.36	30.55
PSI Energy Inc Wabash River	**2,121**	**10,729**	**1.49**	**1.38**	**9.15**	**107.67**	**23.10**
Indiana	2,121	10,729	1.49	1.38	9.15	107.67	23.10
Sullivan	116	10,854	1.60	1.48	9.28	99.60	21.62
Vigo	2,006	10,722	1.48	1.38	9.14	108.14	23.19
Public Service Co of Colorado Araphoe	**857**	**8,763**	**.29**	**.33**	**5.51**	**80.64**	**14.13**
Wyoming	857	8,763	.29	.33	5.51	80.64	14.13
Campbell	857	8,763	.29	.33	5.51	80.64	14.13
Public Service Co of Colorado Cameo	**296**	**11,081**	**.48**	**.43**	**11.80**	**96.72**	**21.44**
Colorado	296	11,081	.48	.43	11.80	96.72	21.44
Garfield	296	11,081	.48	.43	11.80	96.72	21.44
Public Service Co of Colorado Cherokee	**2,057**	**11,337**	**.49**	**.43**	**9.69**	**97.12**	**22.02**
Colorado	2,057	11,337	.49	.43	9.69	97.12	22.02
Delta	53	12,175	.37	.30	7.00	154.36	37.59
Gunnison	22	12,074	.54	.45	8.27	93.40	22.55
Moffat	33	10,910	.36	.33	4.60	88.23	19.25
Routt	1,949	11,313	.49	.44	9.87	95.63	21.64
Public Service Co of Colorado Comanche	**2,492**	**8,598**	**.32**	**.38**	**4.60**	**64.52**	**11.09**
Wyoming	2,492	8,598	.32	.38	4.60	64.52	11.09
Campbell	2,492	8,598	.32	.38	4.60	64.52	11.09
Public Service Co of Colorado Hayden	**1,666**	**10,386**	**.42**	**.41**	**8.21**	**100.90**	**20.96**
Colorado	1,666	10,386	.42	.41	8.21	100.90	20.96
Routt	1,666	10,386	.42	.41	8.21	100.90	20.96
Public Service Co of Colorado Pawnee	**2,525**	**8,412**	**.36**	**.43**	**4.80**	**90.91**	**15.30**
Wyoming	2,525	8,412	.36	.43	4.80	90.91	15.30
Campbell	2,525	8,412	.36	.43	4.80	90.91	15.30
Public Service Co of Colorado Valmont	**590**	**10,842**	**.41**	**.38**	**7.67**	**111.53**	**24.19**
Colorado	590	10,842	.41	.38	7.67	111.53	24.19
Moffat	318	10,459	.34	.33	5.67	109.35	22.87
Routt	272	11,292	.49	.43	10.02	113.89	25.72
Public Service Co of NH Merrimack	**1,125**	**13,170**	**1.68**	**1.28**	**6.85**	**165.30**	**43.54**
Montana	10	9,465	.34	.36	4.10	207.10	39.20
Big Horn	10	9,465	.34	.36	4.10	207.10	39.20
Ohio	18	13,225	2.12	1.60	5.80	215.95	57.12
Harrison	18	13,225	2.12	1.60	5.80	215.95	57.12
Pennsylvania	946	13,183	1.61	1.22	6.87	165.55	43.65
Greene	776	13,108	1.63	1.24	6.98	165.65	43.43
Indiana	104	13,649	1.39	1.02	6.46	170.36	46.51
Westmoreland	66	13,326	1.77	1.32	6.26	156.65	41.75
West Virginia	151	13,326	2.18	1.63	7.00	156.05	41.59
Fayette	17	14,148	.66	.47	4.90	190.00	53.76
Marion	8	13,245	2.07	1.56	7.80	146.40	38.78
Monongalia	85	13,250	2.43	1.83	6.77	153.87	40.78
Upshur	41	13,160	2.30	1.75	8.17	147.55	38.84

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Public Service Co of NH Schiller	**585**	**12,712**	**0.67**	**0.53**	**6.55**	**171.02**	**43.48**
Pennsylvania	10	12,967	1.57	1.21	7.30	169.70	44.01
Greene	10	12,967	1.57	1.21	7.30	169.70	44.01
West Virginia	11	13,402	.91	.68	6.50	247.00	66.21
Boone	11	13,402	.91	.68	6.50	247.00	66.21
Imported	564	12,694	.65	.51	6.53	169.46	43.02
Imported Coal	564	12,694	.65	.51	6.53	169.46	43.02
Public Service Co of NM San Juan	**6,118**	**9,542**	**.70**	**.73**	**22.49**	**184.67**	**35.25**
New Mexico	6,118	9,542	.70	.73	22.49	184.67	35.25
San Juan	6,118	9,542	.70	.73	22.49	184.67	35.25
Public Service Co of Oklahoma Northeastern	**3,272**	**8,743**	**.39**	**.45**	**5.29**	**115.91**	**20.27**
Wyoming	3,272	8,743	.39	.45	5.29	115.91	20.27
Campbell	3,272	8,743	.39	.45	5.29	115.91	20.27
Reliant - HL&P Limestone	**7,169**	**6,756**	**1.20**	**1.77**	**15.67**	**127.07**	**17.17**
Texas	7,169	6,756	1.20	1.77	15.67	127.07	17.17
Freestone	395	6,864	1.18	1.72	14.84	215.00	29.52
Leon	6,773	6,750	1.20	1.78	15.71	121.85	16.45
Reliant - HL&P Parish	**9,254**	**8,593**	**.38**	**.44**	**5.28**	**175.32**	**30.13**
Wyoming	9,254	8,593	.38	.44	5.28	175.32	30.13
Campbell	9,254	8,593	.38	.44	5.28	175.32	30.13
Richmond City of Whitewater	**321**	**11,732**	**2.08**	**1.77**	**10.31**	**152.50**	**35.78**
Indiana	116	11,145	1.79	1.61	8.10	153.93	34.31
Gibson	105	11,142	1.79	1.60	8.08	152.24	33.92
Greene	11	11,179	1.87	1.67	8.28	170.22	38.06
Kentucky	15	12,036	2.03	1.68	13.05	176.56	42.50
Knott	15	12,036	2.03	1.68	13.05	176.56	42.50
Ohio	28	11,267	2.55	2.27	10.08	146.18	32.94
Hocking	26	11,357	2.68	2.36	9.77	142.23	32.31
Tuscarawas	2	10,290	1.22	1.19	13.47	193.17	39.75
Pennsylvania	161	12,205	2.21	1.81	11.68	150.34	36.70
Greene	161	12,205	2.21	1.81	11.68	150.34	36.70
Rochester Gas & Electric Corp Russell 7	**660**	**13,133**	**2.06**	**1.57**	**7.63**	**140.50**	**36.90**
Pennsylvania	278	12,990	1.79	1.38	7.99	156.27	40.60
Armstrong	11	13,030	1.10	.84	7.00	128.60	33.51
Elk	39	12,577	2.37	1.88	11.71	203.90	51.29
Greene	218	13,070	1.78	1.36	7.28	145.16	37.95
Jefferson	10	12,824	.68	.53	10.00	250.50	64.25
West Virginia	381	13,237	2.26	1.71	7.37	129.21	34.21
Lewis	21	13,099	1.77	1.35	7.13	129.92	34.04
Marion	62	13,133	1.77	1.34	7.91	129.06	33.90
Monongalia	289	13,267	2.40	1.81	7.27	129.24	34.29
Webster	10	13,297	2.17	1.63	7.30	127.80	33.99
Rochester Public Utilities Silver Lake	**191**	**11,655**	**.96**	**.82**	**7.41**	**184.21**	**42.94**
Illinois	120	12,119	1.04	.86	6.47	186.94	45.31
Saline	120	12,119	1.04	.86	6.47	186.94	45.31
Indiana	64	10,850	.85	.79	9.20	169.91	36.87
Sullivan	64	10,850	.85	.79	9.20	169.91	36.87
Wyoming	7	11,000	.50	.45	7.20	260.80	57.38
Carbon	7	11,000	.50	.45	7.20	260.80	57.38
Salt River Proj Ag I & P Dist Coronado	**3,466**	**9,739**	**.46**	**.47**	**13.07**	**127.01**	**24.74**
Montana	121	9,388	.32	.34	3.88	124.70	23.41
Big Horn	121	9,388	.32	.34	3.88	124.70	23.41
New Mexico	3,010	9,860	.46	.46	14.28	127.28	25.10
Mckinley	3,010	9,860	.46	.46	14.28	127.28	25.10
Wyoming	335	8,780	.51	.58	5.52	125.16	21.98
Campbell	335	8,780	.51	.58	5.52	125.16	21.98
Salt River Proj Ag I & P Dist Navajo	**8,223**	**10,909**	**.53**	**.48**	**9.35**	**117.14**	**25.56**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Salt River Proj Ag I & P Dist Navajo							
Arizona	8,223	10,909	0.53	0.48	9.35	117.14	25.56
Navajo	8,223	10,909	.53	.48	9.35	117.14	25.56
San Antonio City of JT Deely/Spruce	**5,938**	**8,447**	**.32**	**.38**	**5.45**	**101.01**	**17.07**
Wyoming	5,938	8,447	.32	.38	5.45	101.01	17.07
Campbell	5,922	8,446	.32	.38	5.45	101.00	17.06
Converse	16	8,867	.30	.34	5.20	104.10	18.46
San Miguel Electric Coop Inc San Miguel	**3,282**	**5,200**	**2.06**	**3.97**	**25.56**	**79.59**	**8.28**
Texas	3,282	5,200	2.06	3.97	25.56	79.59	8.28
Atascosa	3,229	5,201	2.06	3.96	25.53	79.68	8.29
McMullen	53	5,151	2.10	4.08	27.20	74.00	7.62
Savannah Electric & Power Inc Kraft	**436**	**12,526**	**.74**	**.59**	**7.45**	**142.18**	**35.62**
Imported	436	12,526	.74	.59	7.45	142.18	35.62
Imported Coal	436	12,526	.74	.59	7.45	142.18	35.62
Savannah Electric & Power Inc McIntosh	**287**	**12,477**	**.72**	**.57**	**154.29**	**167.45**	**41.79**
West Virginia	287	12,477	.72	.57	154.29	167.45	41.79
Boone	153	12,300	.75	.61	12.55	166.00	40.84
Mingo	135	12,677	.68	.53	314.65	169.04	42.86
Seminole Electric Coop Inc Seminole	**3,301**	**12,203**	**2.79**	**2.29**	**8.49**	**180.24**	**43.99**
Illinois	796	11,633	2.73	2.34	8.09	168.44	39.19
White	796	11,633	2.73	2.34	8.09	168.44	39.19
Indiana	76	11,535	3.33	2.89	8.44	204.94	47.28
Gibson	76	11,535	3.33	2.89	8.44	204.94	47.28
Kentucky	2,294	12,360	2.80	2.26	8.68	184.98	45.73
Caldwell	160	12,422	2.74	2.20	7.66	169.66	42.15
Pike	245	12,873	1.59	1.24	8.76	202.91	52.24
Webster	1,889	12,288	2.96	2.41	8.75	183.86	45.19
Pennsylvania	9	13,154	2.59	1.97	7.20	163.10	42.91
Greene	9	13,154	2.59	1.97	7.20	163.10	42.91
West Virginia	126	13,267	2.87	2.16	7.61	153.45	40.72
Harrison	107	13,221	2.94	2.22	7.66	152.08	40.21
Marion	19	13,524	2.48	1.83	7.30	161.00	43.55
Sierra Pacific Power Co North Valmy	**968**	**11,237**	**.40**	**.36**	**8.49**	**157.44**	**35.38**
Utah	941	11,280	.40	.35	8.49	155.97	35.19
Carbon	365	11,459	.39	.34	7.70	121.92	27.94
Sevier	576	11,167	.40	.36	9.00	178.10	39.78
Wyoming	27	9,714	.48	.49	8.24	217.21	42.20
Sweetwater	27	9,714	.48	.49	8.24	217.21	42.20
Sikeston City of Sikeston	**802**	**8,770**	**.34**	**.39**	**5.49**	**108.55**	**19.04**
Wyoming	802	8,770	.34	.39	5.49	108.55	19.04
Campbell	802	8,770	.34	.39	5.49	108.55	19.04
South Carolina Electric&Gas Co Canadys	**997**	**12,599**	**1.26**	**1.00**	**8.61**	**160.31**	**40.40**
Kentucky	877	12,570	1.27	1.01	8.65	160.35	40.31
Bell	10	12,618	.89	.71	7.10	193.90	48.93
Breathitt	25	13,134	1.38	1.05	7.20	166.80	43.82
Harlan	70	12,481	1.27	1.02	10.10	233.00	58.16
Knott	533	12,699	1.26	.99	8.67	149.88	38.07
Letcher	9	13,003	1.30	1.00	7.30	145.70	37.89
Perry	18	12,479	1.22	.98	9.50	173.41	43.28
Pike	212	12,196	1.29	1.06	8.37	160.35	39.11
Tennessee	78	12,955	1.40	1.08	7.42	164.36	42.59
Claiborne	78	12,955	1.40	1.08	7.42	164.36	42.59
Virginia	41	12,543	.96	.76	10.01	151.62	38.04
Dickenson	41	12,543	.96	.76	10.01	151.62	38.04
South Carolina Electric&Gas Co Cope	**1,003**	**12,002**	**.94**	**.78**	**10.06**	**150.13**	**36.04**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
South Carolina Electric&Gas Co Cope							
Kentucky	508	12,294	1.06	0.86	10.21	151.38	37.22
Bell	11	12,840	1.01	.79	6.10	174.60	44.84
Harlan	10	12,940	.84	.65	7.20	172.60	44.67
Knott	378	12,171	1.05	.86	10.55	146.61	35.69
Letcher	43	12,540	1.25	1.00	9.45	134.09	33.63
Perry	19	12,692	1.17	.92	8.90	204.30	51.86
Pike	48	12,635	.97	.77	10.28	171.99	43.46
Virginia	105	12,211	.97	.79	11.57	164.85	40.26
Dickenson	105	12,211	.97	.79	11.57	164.85	40.26
West Virginia	390	11,566	.77	.67	9.44	144.24	33.36
Barbour	10	12,605	.80	.63	11.60	150.60	37.97
Boone	381	11,540	.77	.67	9.39	144.06	33.25
South Carolina Electric&Gas Co Mcmeekin	**631**	**12,183**	**1.01**	**.83**	**10.46**	**158.83**	**38.70**
Kentucky	314	12,297	1.07	.87	10.48	159.66	39.27
Bell	16	12,688	.90	.71	7.29	187.30	47.53
Harlan	25	12,191	1.43	1.17	10.71	229.65	55.99
Knott	251	12,246	1.00	.82	10.80	150.25	36.80
Letcher	7	12,380	1.39	1.12	11.20	134.10	33.20
Perry	7	13,062	1.72	1.32	7.20	212.50	55.51
Pike	7	12,688	1.43	1.13	8.30	147.60	37.45
Tennessee	8	13,028	1.18	.91	8.00	165.60	43.15
Claiborne	8	13,028	1.18	.91	8.00	165.60	43.15
Virginia	261	11,960	.95	.79	10.49	159.48	38.15
Dickenson	261	11,960	.95	.79	10.49	159.48	38.15
West Virginia	49	12,510	.88	.70	10.57	149.17	37.32
Boone	49	12,510	.88	.70	10.57	149.17	37.32
South Carolina Electric&Gas Co Urguhart	**639**	**13,059**	**1.37**	**1.05**	**7.26**	**153.70**	**40.14**
Kentucky	92	12,797	1.22	.95	8.40	147.22	37.68
Knott	75	12,770	1.24	.97	8.60	147.54	37.68
Letcher	8	12,848	1.10	.86	8.60	144.70	37.18
Pike	9	12,974	1.12	.86	6.60	146.70	38.07
Tennessee	547	13,102	1.39	1.06	7.07	154.76	40.55
Claiborne	547	13,102	1.39	1.06	7.07	154.76	40.55
South Carolina Electric&Gas Co Wateree	**1,857**	**12,438**	**1.12**	**.90**	**9.48**	**158.97**	**39.54**
Kentucky	1,257	12,519	1.13	.90	9.64	159.31	39.89
Bell	57	12,757	.94	.73	7.01	185.26	47.27
Breathitt	9	12,474	1.42	1.14	9.70	149.00	37.17
Clay	11	12,644	1.38	1.09	10.70	147.80	37.38
Harlan	50	12,851	.90	.70	8.72	157.02	40.36
Knott	150	12,700	1.19	.94	8.79	144.92	36.81
Letcher	131	11,617	1.24	1.07	8.16	140.91	32.74
Martin	111	12,624	1.00	.79	9.91	157.02	39.64
Perry	90	12,987	1.48	1.14	7.66	198.89	51.66
Pike	647	12,528	1.10	.88	10.66	159.04	39.85
Tennessee	218	11,895	1.29	1.09	6.85	160.09	38.09
Claiborne	218	11,895	1.29	1.09	6.85	160.09	38.09
Virginia	242	12,498	1.08	.86	10.75	162.75	40.68
Buchanan	18	12,852	1.26	.98	12.20	148.00	38.04
Dickenson	172	12,351	1.01	.82	11.08	166.16	41.04
Wise	52	12,863	1.25	.97	9.20	156.98	40.39
West Virginia	140	12,449	.77	.62	9.92	147.70	36.77
Barbour	57	12,422	.75	.60	10.66	152.60	37.91
Boone	83	12,467	.78	.62	9.41	144.33	35.99
South Carolina Electric&Gas Co Williams	**1,568**	**12,951**	**.81**	**.62**	**7.54**	**152.36**	**39.46**
Kentucky	1,568	12,951	.81	.62	7.54	152.36	39.46
Harlan	271	13,090	.72	.55	7.02	169.76	44.44
Knott	669	12,917	.81	.63	8.14	141.72	36.61
Perry	535	12,951	.85	.65	7.07	157.10	40.69
Pike	93	12,791	.79	.62	7.46	150.14	38.41
South Carolina Pub Serv Auth Cross	**3,282**	**12,735**	**1.32**	**1.04**	**9.01**	**153.98**	**39.22**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
South Carolina Pub Serv Auth Cross							
Kentucky	3,108	12,734	1.33	1.04	8.84	151.17	38.50
Bell	9	12,382	1.69	1.36	11.20	177.40	43.93
Harlan	776	12,594	1.22	.97	9.93	167.11	42.09
Knott	91	12,662	1.40	1.11	9.58	145.32	36.80
Letcher	52	13,123	1.45	1.11	7.13	153.68	40.33
Perry	255	11,932	1.37	1.15	12.81	196.76	46.96
Pike	1,925	12,892	1.36	1.05	7.87	139.38	35.94
Virginia	145	12,701	1.17	.92	12.66	207.93	52.82
Russell	145	12,701	1.17	.92	12.66	207.93	52.82
West Virginia	29	12,962	1.00	.77	9.28	185.14	48.00
Greenbrier	25	13,013	1.05	.81	9.30	175.70	45.73
Mcdowell	4	12,601	.67	.53	9.10	253.70	63.94
South Carolina Pub Serv Auth Grainger	**422**	**12,338**	**1.35**	**1.09**	**9.14**	**171.53**	**42.33**
Kentucky	422	12,338	1.35	1.09	9.14	171.53	42.33
Harlan	103	12,143	1.37	1.12	11.21	223.25	54.22
Letcher	48	12,786	1.52	1.19	7.57	179.69	45.95
Pike	271	12,332	1.31	1.06	8.64	150.70	37.17
South Carolina Pub Serv Auth Jefferies	**732**	**12,555**	**1.38**	**1.10**	**9.54**	**166.33**	**41.76**
Kentucky	704	12,556	1.38	1.10	9.50	166.56	41.82
Bell	9	12,604	1.73	1.37	10.10	178.80	45.07
Harlan	387	12,372	1.32	1.07	10.28	190.97	47.26
Letcher	122	13,140	1.53	1.16	7.05	154.91	40.71
Pike	186	12,552	1.39	1.10	9.43	123.78	31.07
Virginia	29	12,538	1.31	1.04	10.58	160.67	40.29
Russell	29	12,538	1.31	1.04	10.58	160.67	40.29
South Carolina Pub Serv Auth Winyah	**3,440**	**12,615**	**1.17**	**.92**	**9.71**	**151.58**	**38.24**
Kentucky	3,323	12,611	1.17	.92	9.61	150.22	37.89
Bell	9	12,456	1.77	1.42	11.25	168.10	41.88
Harlan	1,710	12,682	1.15	.91	9.41	151.76	38.49
Knott	50	12,789	1.97	1.54	8.71	150.25	38.43
Letcher	19	12,842	1.52	1.19	7.92	159.72	41.02
Perry	361	11,824	1.07	.90	12.81	179.46	42.44
Pike	1,173	12,740	1.17	.92	8.96	139.34	35.50
Virginia	118	12,726	1.14	.89	12.50	189.73	48.29
Russell	118	12,726	1.14	.89	12.50	189.73	48.29
South Mississippi El Pwr Assn R D Morrow	**1,027**	**12,279**	**.96**	**.79**	**11.62**	**152.51**	**37.45**
Alabama	25	12,303	.76	.62	11.82	191.41	47.10
Tuscaloosa	25	12,303	.76	.62	11.82	191.41	47.10
Kentucky	863	12,175	.96	.79	11.85	151.40	36.87
Leslie	589	12,111	.94	.78	11.85	147.94	35.83
Pike	274	12,314	1.00	.82	11.85	158.72	39.09
Virginia	139	12,918	1.02	.79	10.18	152.23	39.33
Wise	99	12,912	1.02	.79	10.28	152.21	39.31
Unknown[1]	40	12,934	1.03	.80	9.93	152.28	39.39
Southern California Edison Co Mohave	**4,933**	**10,963**	**.49**	**.45**	**10.02**	**123.70**	**27.12**
Arizona	4,933	10,963	.49	.45	10.02	123.70	27.12
Navajo	4,933	10,963	.49	.45	10.02	123.70	27.12
Southern Illinois Power Coop Marion	**960**	**10,168**	**2.97**	**2.93**	**16.57**	**90.44**	**18.39**
Illinois	960	10,168	2.97	2.93	16.57	90.44	18.39
Franklin	119	8,162	1.06	1.30	22.56	48.04	7.84
Gallatin	110	9,229	3.36	3.64	22.00	86.66	16.00
Jackson	12	10,840	3.71	3.42	11.88	57.81	12.53
Jefferson	5	7,981	1.35	1.69	18.12	51.73	8.26
Logan	2	11,563	3.40	2.94	9.40	80.10	18.52
Perry	253	10,975	3.26	2.97	11.66	89.66	19.68
Randolph	16	10,968	2.93	2.67	9.71	122.79	26.94
Saline	238	11,131	4.20	3.77	16.90	117.39	26.13
Williamson	205	9,662	2.09	2.17	16.69	78.38	15.15
Southern Indiana Gas & Elec Co A B Brown	**1,015**	**11,448**	**3.05**	**2.66**	**8.74**	**100.60**	**23.03**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Southern Indiana Gas & Elec Co A B Brown							
Illinois	325	11,740	2.85	2.43	7.36	98.63	23.16
White	325	11,740	2.85	2.43	7.36	98.63	23.16
Indiana	690	11,310	3.14	2.78	9.40	101.56	22.97
Knox	194	11,345	3.25	2.86	9.71	102.92	23.35
Pike	262	11,502	1.72	1.49	7.01	103.24	23.75
Warrick	234	11,066	4.66	4.21	11.81	98.45	21.79
Southern Indiana Gas & Elec Co Culley	**857**	**11,303**	**4.06**	**3.59**	**10.61**	**97.93**	**22.14**
Illinois	55	12,063	1.12	.93	5.92	153.15	36.95
Saline	55	12,063	1.12	.93	5.92	153.15	36.95
Indiana	802	11,251	4.26	3.79	10.93	93.87	21.12
Knox	11	11,450	3.22	2.81	8.89	109.53	25.08
Pike	60	11,185	1.73	1.55	8.62	101.75	22.76
Warrick	731	11,254	4.48	3.99	11.15	93.00	20.93
Southern Indiana Gas & Elec Co Warrick	**289**	**11,581**	**1.67**	**1.44**	**6.63**	**111.18**	**25.75**
Illinois	3	11,767	2.97	2.52	6.90	110.10	25.91
White	3	11,767	2.97	2.52	6.90	110.10	25.91
Indiana	272	11,609	1.68	1.45	6.49	110.75	25.71
Knox	41	11,353	2.79	2.46	8.12	111.66	25.35
Pike	132	11,705	1.23	1.05	5.54	102.25	23.94
Spencer	98	11,588	1.83	1.58	7.09	121.93	28.26
Kentucky	15	11,014	1.10	1.00	9.22	119.85	26.40
Boyd	2	10,628	.78	.73	18.00	158.40	33.67
Ohio	13	11,064	1.14	1.03	8.07	115.00	25.45
Southwestern Electric Power Co Flint Creek	**1,901**	**8,463**	**.35**	**.42**	**4.82**	**148.92**	**25.21**
Wyoming	1,901	8,463	.35	.42	4.82	148.92	25.21
Campbell	1,901	8,463	.35	.42	4.82	148.92	25.21
Southwestern Electric Power Co Pirkey	**3,130**	**6,600**	**1.53**	**2.32**	**14.37**	**155.52**	**20.53**
Texas	3,079	6,568	1.55	2.37	14.61	155.46	20.42
Harrison	3,079	6,568	1.55	2.37	14.61	155.46	20.42
Wyoming	51	8,507	.10	.12	.00	158.60	26.98
Campbell	51	8,507	.10	.12	.00	158.60	26.98
Southwestern Electric Power Co Welsh Station	**6,852**	**8,534**	**.32**	**.37**	**4.73**	**149.06**	**25.44**
Wyoming	6,852	8,534	.32	.37	4.73	149.06	25.44
Campbell	6,852	8,534	.32	.37	4.73	149.06	25.44
Southwestern Public Service Co Harrington	**4,533**	**8,841**	**.26**	**.30**	**5.39**	**119.57**	**21.14**
Wyoming	4,533	8,841	.26	.30	5.39	119.57	21.14
Campbell	4,533	8,841	.26	.30	5.39	119.57	21.14
Southwestern Public Service Co Tolk	**4,031**	**8,714**	**.27**	**.31**	**5.57**	**158.88**	**27.69**
Wyoming	4,031	8,714	.27	.31	5.57	158.88	27.69
Campbell	4,031	8,714	.27	.31	5.57	158.88	27.69
Springfield City of (MO) James River	**939**	**9,507**	**.37**	**.39**	**4.61**	**123.88**	**23.55**
Colorado	36	11,906	.36	.30	8.10	218.66	52.07
Gunnison	36	11,906	.36	.30	8.10	218.66	52.07
Illinois	120	12,037	1.48	1.23	6.32	140.34	33.79
Jefferson	120	12,037	1.48	1.23	6.32	140.34	33.79
Utah	10	11,712	.49	.42	6.50	227.40	53.27
Carbon	10	11,712	.49	.42	6.50	227.40	53.27
Wyoming	773	8,974	.20	.22	4.15	112.85	20.25
Campbell	773	8,974	.20	.22	4.15	112.85	20.25
Springfield City of (MO) Southwest	**817**	**8,904**	**.20**	**.22**	**4.29**	**110.65**	**19.70**
Wyoming	817	8,904	.20	.22	4.29	110.65	19.70
Campbell	817	8,904	.20	.22	4.29	110.65	19.70
Springfield City of (IL) Dallman	**1,065**	**10,476**	**3.05**	**2.91**	**9.41**	**113.84**	**23.85**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Springfield City of (IL) Dallman							
Illinois	1,065	10,476	3.05	2.91	9.41	113.84	23.85
Logan	999	10,489	3.19	3.04	9.49	112.54	23.61
Macoupin	66	10,281	.88	.85	8.22	133.95	27.54
Springfield City of (IL) Lakeside	**157**	**10,268**	**.86**	**.84**	**8.19**	**134.29**	**27.58**
Illinois	157	10,268	.86	.84	8.19	134.29	27.58
Macoupin	157	10,268	.86	.84	8.19	134.29	27.58
St Joseph Light and Power Co Lakeroad	**423**	**9,719**	**.34**	**.35**	**5.71**	**113.80**	**22.12**
Colorado	21	12,286	.61	.50	11.00	131.17	32.23
Gunnison	21	12,286	.61	.50	11.00	131.17	32.23
Wyoming	402	9,585	.32	.34	5.43	112.64	21.59
Campbell	194	8,744	.26	.30	5.18	98.03	17.14
Carbon	145	11,045	.42	.38	5.78	136.54	30.16
Converse	63	8,790	.29	.33	5.40	87.74	15.42
Sunflower Electric Power Corp Holcomb Unit #1	**1,363**	**8,468**	**.31**	**.36**	**5.28**	**104.90**	**17.76**
Wyoming	1,363	8,468	.31	.36	5.28	104.90	17.76
Campbell	1,363	8,468	.31	.36	5.28	104.90	17.76
Tampa Electric Co Davant Transfer[3]	**7,029**	**11,522**	**2.25**	**1.95**	**8.27**	**154.86**	**35.69**
Illinois	4,625	11,828	2.48	2.10	8.58	157.73	37.31
Clinton	38	11,846	1.32	1.11	5.34	162.43	38.48
Gallatin	1,638	12,167	2.96	2.43	9.91	136.43	33.20
Knox	42	11,138	2.66	2.39	8.90	143.90	32.06
Logan	204	11,127	2.62	2.36	8.52	143.97	32.04
Perry	1,118	11,000	2.89	2.63	8.73	214.44	47.18
Saline	1,564	12,169	1.71	1.40	7.17	145.36	35.38
Williamson	10	12,003	1.22	1.02	5.10	171.50	41.17
Unknown[1]	10	12,516	2.81	2.25	9.40	134.50	33.67
Indiana	791	11,319	3.16	2.79	8.83	138.33	31.31
Gibson	791	11,319	3.16	2.79	8.83	138.33	31.31
Kentucky	665	12,102	2.24	1.85	9.67	148.15	35.86
Henderson	72	11,119	2.58	2.32	8.38	145.44	32.34
Letcher	30	12,742	1.18	.93	8.90	152.20	38.79
Pike	48	12,668	1.03	.82	8.09	213.54	54.11
Union	148	12,196	2.01	1.65	11.06	152.36	37.16
Webster	367	12,129	2.51	2.07	9.63	137.62	33.38
Wyoming	679	8,729	.25	.28	4.70	144.40	25.21
Campbell	679	8,729	.25	.28	4.70	144.40	25.21
Imported	269	12,478	.63	.50	6.94	186.82	46.62
Imported Coal	269	12,478	.63	.50	6.94	186.82	46.62
Tampa Electric Co Gannon	**301**	**12,633**	**1.20**	**.95**	**8.83**	**175.16**	**44.26**
Kentucky	301	12,633	1.20	.95	8.83	175.16	44.26
Letcher	111	12,674	1.28	1.01	9.25	152.20	38.58
Pike	119	12,552	1.11	.89	8.07	210.40	52.82
Union	70	12,706	1.23	.97	9.45	152.20	38.68
Tennessee Valley Authority Bull Run[4]	**2,104**	**12,421**	**.96**	**.77**	**10.10**	**135.74**	**33.72**
Kentucky	1,481	12,443	.97	.78	10.12	143.05	35.60
Harlan	294	12,654	.95	.75	8.77	137.60	34.82
Knott	377	12,360	.90	.73	10.64	167.15	41.32
Leslie	633	12,374	1.04	.84	10.30	122.78	30.39
Letcher	8	12,500	.96	.77	13.00	183.60	45.90
Perry	67	12,439	.80	.64	10.46	168.92	42.02
Pike	103	12,567	.91	.73	10.59	174.75	43.92
Virginia	595	12,360	.93	.76	9.98	110.98	27.43
Lee	595	12,360	.93	.76	9.98	110.98	27.43
West Virginia	29	12,500	1.00	.80	11.00	267.57	66.89
Boone	29	12,500	1.00	.80	11.00	267.57	66.89
Tennessee Valley Authority Colbert[4]	**1,075**	**11,896**	**1.39**	**1.17**	**12.95**	**136.25**	**32.42**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Tennessee Valley Authority Colbert[4]							
Kentucky	780	11,886	1.61	1.36	12.33	115.58	27.48
Martin	28	11,500	.85	.74	15.00	193.91	44.60
Webster	751	11,901	1.64	1.38	12.23	112.72	26.83
Pennsylvania	5	13,355	2.38	1.78	7.60	112.20	29.97
Greene	5	13,355	2.38	1.78	7.60	112.20	29.97
West Virginia	290	11,896	.76	.64	14.70	192.21	45.73
Boone	145	11,992	.73	.61	14.35	192.22	46.10
Fayette	47	11,792	.74	.63	15.30	195.50	46.11
Kanawha	64	11,613	.75	.65	15.90	198.50	46.10
Nicholas	34	12,169	.95	.78	13.09	176.39	42.93
Tennessee Valley Authority Cora Transfer[4]	**1,939**	**10,436**	**.35**	**.34**	**6.33**	**119.16**	**24.87**
Colorado	24	11,964	.50	.42	8.90	122.10	29.22
Gunnison	24	11,964	.50	.42	8.90	122.10	29.22
Utah	903	12,194	.51	.42	8.47	131.65	32.11
Carbon	214	11,770	.49	.41	7.13	137.37	32.34
Emery	689	12,326	.52	.42	8.89	129.95	32.04
Wyoming	1,013	8,832	.20	.23	4.35	103.70	18.32
Campbell	1,013	8,832	.20	.23	4.35	103.70	18.32
Tennessee Valley Authority Cumberland[4]	**6,032**	**12,001**	**2.76**	**2.30**	**9.42**	**108.54**	**26.05**
Illinois	1,876	12,286	2.89	2.35	9.25	111.16	27.31
Gallatin	918	12,381	2.94	2.37	9.97	112.02	27.74
Saline	867	12,247	2.82	2.30	8.60	105.09	25.74
White	91	11,683	3.06	2.62	8.21	162.46	37.96
Kentucky	3,777	11,783	2.70	2.29	9.47	103.64	24.42
Breathitt	66	11,972	1.01	.84	10.86	193.86	46.42
Daviess	31	12,775	2.79	2.18	9.13	124.60	31.83
Union	3,037	11,719	2.84	2.43	8.98	98.84	23.17
Webster	643	12,018	2.18	1.82	11.64	115.53	27.77
Pennsylvania	211	13,170	2.71	2.06	7.72	111.37	29.34
Greene	211	13,170	2.71	2.06	7.72	111.37	29.34
Virginia	79	12,529	2.23	1.78	12.86	184.84	46.32
Wise	79	12,529	2.23	1.78	12.86	184.84	46.32
West Virginia	89	12,000	2.90	2.42	12.00	178.36	42.81
Marshall	89	12,000	2.90	2.42	12.00	178.36	42.81
Tennessee Valley Authority Gallatin[4]	**16**	**12,667**	**2.43**	**1.92**	**8.77**	**117.21**	**29.69**
Illinois	16	12,667	2.43	1.92	8.77	117.21	29.69
Gallatin	16	12,667	2.43	1.92	8.77	117.21	29.69
Tennessee Valley Authority GRT Terminal[4]	**8,951**	**10,921**	**.95**	**.87**	**7.72**	**122.19**	**26.69**
Alabama	12	10,500	1.40	1.33	20.00	123.33	25.90
Franklin	12	10,500	1.40	1.33	20.00	123.33	25.90
Colorado	1,910	11,987	.54	.45	9.03	128.75	30.86
Delta	370	11,908	.39	.33	8.34	132.70	31.60
Gunnison	1,487	12,036	.57	.48	9.15	126.72	30.50
Routt	53	11,162	.52	.46	10.53	160.68	35.87
Illinois	668	12,098	1.66	1.38	7.33	144.62	34.99
Gallatin	56	12,680	2.54	2.00	8.57	104.43	26.48
Jefferson	149	12,047	1.50	1.25	6.37	110.74	26.68
Saline	463	12,043	1.61	1.34	7.48	160.65	38.69
Indiana	43	11,683	1.18	1.01	5.00	141.30	33.02
Pike	43	11,683	1.18	1.01	5.00	141.30	33.02
Kentucky	1,225	12,127	2.26	1.86	10.89	124.95	30.31
Breathitt	54	11,845	1.20	1.01	12.00	193.31	45.80
Hopkins	14	11,375	2.07	1.82	9.23	113.59	25.84
Martin	6	12,017	.85	.71	12.60	143.10	34.39
Muhlenberg	28	10,000	4.25	4.25	24.00	122.24	24.45
Pike	12	13,083	.89	.68	8.90	223.20	58.40
Webster	1,111	12,195	2.28	1.87	10.54	120.64	29.42
Pennsylvania	663	13,167	2.46	1.87	7.74	111.33	29.32
Greene	663	13,167	2.46	1.87	7.74	111.33	29.32

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Tennessee Valley Authority GRT Terminal[4]							
Utah	750	12,064	0.73	0.60	9.07	145.12	35.01
Carbon	409	12,334	.96	.78	7.74	132.44	32.67
Emery	341	11,740	.45	.38	10.67	161.06	37.82
Virginia	192	12,839	.91	.71	10.26	126.58	32.50
Lee	12	12,050	.85	.71	13.20	111.10	26.78
Wise	180	12,893	.92	.71	10.06	127.57	32.90
West Virginia	114	11,597	1.24	1.07	13.01	181.80	42.17
Boone	16	12,185	.91	.74	13.04	179.16	43.66
Mingo	98	11,500	1.30	1.13	13.00	182.27	41.92
Wyoming	3,372	8,808	.30	.34	5.26	102.52	18.06
Campbell	3,349	8,795	.30	.34	5.25	102.16	17.97
Carbon	23	10,715	.60	.56	6.40	147.20	31.54
Tennessee Valley Authority Johnsonville[4]	**8**	**12,079**	**1.29**	**1.06**	**11.02**	**172.29**	**41.62**
Kentucky	8	12,079	1.29	1.06	11.02	172.29	41.62
Breathitt	7	12,102	1.15	.95	10.90	187.30	45.33
Webster	2	11,981	1.88	1.57	11.52	106.13	25.43
Tennessee Valley Authority Kingston[4]	**3,408**	**12,278**	**1.05**	**.85**	**11.56**	**131.45**	**32.28**
Colorado	67	12,202	.43	.36	8.11	201.16	49.09
Delta	54	12,178	.37	.31	6.70	203.65	49.60
Las Animas	13	12,300	.70	.57	14.00	190.90	46.96
Kentucky	2,591	12,200	1.11	.91	12.04	132.28	32.28
Bell	18	12,500	1.30	1.04	12.00	258.60	64.65
Harlan	143	12,567	1.14	.90	10.43	166.79	41.92
Knott	278	12,415	1.25	1.01	10.05	117.12	29.08
Leslie	418	12,000	.98	.82	12.24	130.15	31.24
Martin	807	12,109	1.06	.88	12.36	130.18	31.53
Perry	59	12,539	.77	.61	11.03	166.73	41.81
Pike	850	12,208	1.17	.96	12.69	128.37	31.34
Unknown[1]	19	12,936	1.21	.94	8.65	166.13	42.98
Tennessee	383	12,661	.85	.67	10.42	129.97	32.91
Campbell	69	12,703	.90	.71	8.17	169.62	43.09
Cumberland	220	12,659	.74	.58	11.77	122.45	31.00
Scott	95	12,634	1.08	.86	8.92	118.35	29.90
Virginia	366	12,443	.94	.76	10.01	114.65	28.53
Lee	219	12,274	.89	.72	9.49	106.10	26.05
Wise	147	12,695	1.03	.81	10.80	127.02	32.25
Tennessee Valley Authority Paradise[4]	**4,779**	**10,492**	**3.86**	**3.68**	**18.69**	**96.29**	**20.21**
Illinois	276	12,412	2.88	2.32	9.63	114.65	28.46
Gallatin	247	12,427	2.89	2.32	9.72	115.11	28.61
Saline	29	12,285	2.84	2.31	8.84	110.75	27.21
Kentucky	4,504	10,374	3.92	3.78	19.24	94.95	19.70
Christian	189	11,127	3.17	2.85	12.51	101.40	22.56
Hopkins	904	10,624	3.55	3.34	15.97	101.80	21.63
Muhlenberg	2,793	10,113	4.14	4.10	21.26	88.54	17.91
Union	82	11,245	2.66	2.37	12.93	106.62	23.98
Webster	535	10,913	3.81	3.49	17.60	110.50	24.12
Tennessee Valley Authority Sevier[4]	**1,780**	**12,714**	**.91**	**.71**	**10.61**	**132.97**	**33.81**
Kentucky	312	12,398	.86	.69	11.23	162.02	40.17
Harlan	88	12,883	.80	.62	10.28	124.24	32.01
Martin	134	11,948	.93	.78	12.04	143.88	34.38
Pike	90	12,592	.82	.65	10.98	225.79	56.86
Virginia	1,468	12,781	.91	.72	10.48	126.99	32.46
Lee	113	12,322	.90	.73	10.17	109.45	26.97
Wise	1,355	12,819	.92	.71	10.50	128.39	32.92
Tennessee Valley Authority Shawnee[4]	**3,379**	**11,447**	**.55**	**.48**	**7.92**	**133.25**	**30.51**
Colorado	2,512	11,936	.41	.34	8.13	137.92	32.92
Delta	2,110	11,944	.39	.32	7.98	138.82	33.16
Gunnison	402	11,895	.52	.44	8.88	133.14	31.67

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Tennessee Valley Authority Shawnee[4]							
Illinois	12	10,667	3.36	3.15	8.17	126.23	26.93
Jefferson	12	10,667	3.36	3.15	8.17	126.23	26.93
Kentucky	172	11,986	3.27	2.73	10.55	114.07	27.35
Hopkins	37	11,823	3.43	2.90	9.97	110.22	26.06
Webster	136	12,031	3.22	2.68	10.70	115.10	27.69
Utah	181	11,625	.51	.44	9.25	151.60	35.25
Carbon	125	11,376	.50	.44	8.90	158.63	36.09
Emery	56	12,175	.55	.45	10.03	137.03	33.37
Wyoming	502	8,766	.29	.33	5.47	101.91	17.87
Campbell	502	8,766	.29	.33	5.47	101.91	17.87
Tennessee Valley Authority Widows Creek[4]	**3,084**	**11,905**	**2.36**	**1.98**	**12.26**	**139.50**	**33.22**
Colorado	9	12,250	.65	.53	11.00	169.55	41.54
Gunnison	9	12,250	.65	.53	11.00	169.55	41.54
Illinois	407	12,063	2.90	2.40	9.59	130.66	31.52
Gallatin	187	12,378	2.87	2.32	10.31	114.68	28.39
Jackson	26	12,112	3.61	2.98	14.00	132.30	32.05
Saline	31	12,184	3.25	2.66	9.12	114.88	27.99
White	163	11,672	2.76	2.36	8.14	152.89	35.69
Kentucky	1,906	11,755	2.86	2.44	12.87	136.28	32.04
Breathitt	26	11,866	1.18	1.00	11.64	206.92	49.11
Daviess	326	12,226	3.75	3.07	12.61	127.78	31.25
Harlan	18	12,575	.83	.66	7.51	145.73	36.65
Hopkins	476	11,419	3.58	3.13	13.47	111.99	25.58
Knott	45	12,000	.89	.74	12.00	184.52	44.29
Leslie	60	12,000	.96	.80	12.00	141.91	34.06
Martin	130	11,597	.81	.70	14.39	199.62	46.30
Muhlenberg	115	11,271	2.95	2.61	11.24	137.46	30.99
Pike	186	12,348	.85	.68	11.13	196.53	48.53
Union	9	10,152	3.38	3.33	10.50	156.20	31.71
Webster	516	11,644	3.41	2.93	13.54	115.50	26.90
Virginia	140	12,405	.91	.73	9.50	123.54	30.65
Lee	140	12,405	.91	.73	9.50	123.54	30.65
West Virginia	622	12,144	.81	.66	12.77	158.03	38.38
Boone	392	12,399	.75	.61	12.16	145.11	35.98
Kanawha	33	11,853	.71	.60	15.67	196.21	46.51
Logan	124	11,570	.69	.59	13.40	191.12	44.22
Marshall	17	12,000	2.90	2.42	12.00	180.00	43.20
Mingo	51	11,800	.85	.72	14.40	149.19	35.21
Nicholas	5	12,265	.76	.62	12.35	178.68	43.83
Texas Municipal Power Agency Gibbons Creek	**2,089**	**8,449**	**.31**	**.37**	**5.47**	**134.41**	**22.71**
Montana	1	8,746	.66	.75	8.71	123.70	21.64
Big Horn	1	8,746	.66	.75	8.71	123.70	21.64
Wyoming	2,088	8,449	.31	.37	5.47	134.41	22.71
Campbell	2,088	8,449	.31	.37	5.47	134.41	22.71
Texas-New Mexico Power Co TNP 1	**1,881**	**6,758**	**.93**	**1.38**	**16.44**	**150.68**	**20.37**
Texas	1,881	6,758	.93	1.38	16.44	150.68	20.37
Robertson	1,881	6,758	.93	1.38	16.44	150.68	20.37
TXU Electric Co Big Brown	**5,383**	**7,323**	**.60**	**.81**	**12.09**	**149.31**	**21.87**
Texas	3,358	6,622	.76	1.15	15.99	136.72	18.11
Freestone	3,358	6,622	.76	1.15	15.99	136.72	18.11
Wyoming	2,025	8,487	.32	.38	5.62	165.61	28.11
Campbell	2,025	8,487	.32	.38	5.62	165.61	28.11
TXU Electric Co Martin Lake	**11,604**	**6,796**	**1.10**	**1.62**	**12.63**	**113.34**	**15.41**
Texas	10,597	6,650	1.17	1.76	13.30	111.22	14.79
Panola	10,597	6,650	1.17	1.76	13.30	111.22	14.79
Wyoming	1,007	8,330	.33	.40	5.53	131.16	21.85
Campbell	1,007	8,330	.33	.40	5.53	131.16	21.85
TXU Electric Co Monticello	**9,474**	**6,646**	**.50**	**.76**	**15.77**	**144.69**	**19.23**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
TXU Electric Co Monticello							
Texas	6,831	5,951	0.58	0.98	19.72	159.65	19.00
Titus	6,831	5,951	.58	.98	19.72	159.65	19.00
Wyoming	2,643	8,442	.30	.36	5.55	117.43	19.83
Campbell	2,643	8,442	.30	.36	5.55	117.43	19.83
TXU Electric Co Sandow No 4	**836**	**6,441**	**1.08**	**1.67**	**16.65**	**121.24**	**15.62**
Texas	836	6,441	1.08	1.67	16.65	121.24	15.62
Milam	836	6,441	1.08	1.67	16.65	121.24	15.62
Tri-State G & T Assn, Inc. Craig	**4,555**	**10,181**	**.38**	**.37**	**5.93**	**108.02**	**21.99**
Colorado	4,555	10,181	.38	.37	5.93	108.02	21.99
Moffat	4,555	10,181	.38	.37	5.93	108.02	21.99
Tri-State G & T Assn, Inc. Nucla	**365**	**10,666**	**.97**	**.91**	**20.30**	**112.80**	**24.06**
Colorado	365	10,666	.97	.91	20.30	112.80	24.06
Montrose	365	10,666	.97	.91	20.30	112.80	24.06
Tucson Electric Power Co Irvington	**339**	**11,032**	**.48**	**.44**	**10.58**	**198.46**	**43.79**
Colorado	267	11,287	.50	.44	9.94	176.14	39.76
Rio Blanco	21	11,241	.47	.42	10.30	196.40	44.15
Routt	246	11,292	.50	.44	9.91	174.38	39.38
New Mexico	72	10,082	.44	.43	12.96	291.61	58.80
Mckinley	72	10,082	.44	.43	12.96	291.61	58.80
Tucson Electric Power Co Springerville	**3,331**	**9,274**	**.86**	**.93**	**17.60**	**134.64**	**24.97**
New Mexico	3,331	9,274	.86	.93	17.60	134.64	24.97
Mckinley	3,331	9,274	.86	.93	17.60	134.64	24.97
United Power Assn Stanton	**937**	**6,685**	**.72**	**1.08**	**8.75**	**74.36**	**9.94**
North Dakota	937	6,685	.72	1.08	8.75	74.36	9.94
Mercer	937	6,685	.72	1.08	8.75	74.36	9.94
UtiliCorp United Inc Sibley	**1,683**	**9,725**	**.33**	**.34**	**5.90**	**93.30**	**18.15**
Utah	430	12,505	.44	.35	7.10	111.49	27.88
Emery	430	12,505	.44	.35	7.10	111.49	27.88
Wyoming	1,254	8,772	.29	.33	5.49	84.41	14.81
Campbell	1,254	8,772	.29	.33	5.49	84.41	14.81
Vineland City of H M Down	**27**	**13,051**	**.92**	**.71**	**9.54**	**186.97**	**48.80**
West Virginia	27	13,051	.92	.71	9.54	186.97	48.80
Unknown[1]	27	13,051	.92	.71	9.54	186.97	48.80
Virginia Electric & Power Co Bremo Bluff	**508**	**12,564**	**.98**	**.78**	**10.68**	**173.33**	**43.55**
Kentucky	193	12,517	1.12	.90	10.76	204.59	51.22
Floyd	23	12,732	1.33	1.04	9.65	171.10	43.57
Knott	43	12,326	1.17	.95	11.35	178.27	43.95
Letcher	107	12,516	.97	.78	10.99	225.63	56.48
Pike	21	12,677	1.53	1.21	9.60	187.65	47.58
Virginia	64	13,056	.99	.76	10.67	182.58	47.68
Buchanan	10	12,989	.96	.74	12.10	180.36	46.85
Dickenson	53	13,069	1.00	.77	10.39	183.02	47.84
West Virginia	251	12,475	.87	.69	10.63	146.74	36.61
Boone	206	12,383	.86	.70	10.96	134.51	33.31
Greenbrier	15	12,577	1.16	.92	11.47	165.61	41.66
Kanawha	30	13,051	.76	.58	7.98	216.73	56.57
Virginia Electric & Power Co Chesapeake Energy	**1,268**	**12,910**	**.88**	**.68**	**9.19**	**177.28**	**45.77**
Kentucky	192	12,708	.76	.60	9.43	204.22	51.91
Martin	68	12,674	.77	.61	9.11	231.91	58.78
Pike	125	12,726	.76	.60	9.60	189.24	48.17
Virginia	974	12,948	.90	.70	9.21	168.42	43.61
Buchanan	305	12,834	.82	.64	10.74	150.71	38.68
Lee	253	13,041	.66	.51	6.55	163.66	42.68
Wise	416	12,974	1.11	.86	9.70	184.13	47.78

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Virginia Electric & Power Co Chesapeake Energy							
West Virginia	102	12,927	0.83	0.64	8.54	212.10	54.84
Boone	82	12,951	.86	.67	8.29	210.58	54.54
Mingo	10	12,962	.74	.57	6.82	234.33	60.75
Wyoming	10	12,694	.66	.52	12.33	202.28	51.36
Virginia Electric & Power Co Clover	**2,367**	**12,731**	**1.07**	**.84**	**10.26**	**156.91**	**39.95**
Kentucky	617	12,455	.88	.70	10.36	202.03	50.33
Knott	39	12,221	1.08	.88	11.50	187.59	45.85
Letcher	29	12,196	.95	.78	13.46	311.51	75.98
Martin	457	12,463	.83	.67	10.11	196.77	49.05
Pike	92	12,594	.99	.79	10.09	200.28	50.45
Pennsylvania	76	12,830	1.40	1.09	11.10	228.62	58.66
Somerset	76	12,830	1.40	1.09	11.10	228.62	58.66
Virginia	1,637	12,828	1.13	.88	10.21	137.05	35.16
Buchanan	112	12,987	1.12	.86	10.74	162.63	42.24
Dickenson	11	13,379	.80	.60	8.98	144.15	38.57
Lee	162	12,663	.81	.64	9.07	163.58	41.43
Wise	1,351	12,830	1.17	.91	10.32	131.69	33.79
West Virginia	37	12,865	.82	.64	8.94	157.95	40.64
Boone	32	12,921	.84	.65	8.15	155.07	40.08
Wyoming	5	12,483	.69	.55	14.22	177.92	44.42
Virginia Electric & Power Co Chesterfield	**2,451**	**12,886**	**1.04**	**.81**	**9.14**	**171.12**	**44.10**
Kentucky	840	12,883	1.30	1.01	8.28	188.63	48.60
Bell	19	12,588	1.61	1.28	10.17	176.61	44.46
Floyd	187	12,994	1.20	.92	7.55	267.82	69.60
Knott	163	12,867	1.22	.95	8.32	193.05	49.68
Letcher	288	12,870	1.34	1.04	8.47	150.56	38.75
Pike	184	12,836	1.37	1.07	8.49	164.12	42.13
Virginia	383	12,974	1.09	.84	11.08	183.59	47.64
Buchanan	11	12,436	1.24	1.00	12.13	263.54	65.55
Dickenson	284	12,999	1.02	.79	11.36	177.82	46.23
Wise	88	12,964	1.27	.98	10.04	192.38	49.88
West Virginia	1,228	12,859	.85	.66	9.13	155.19	39.91
Boone	1,047	12,855	.86	.67	9.03	153.23	39.40
Greenbrier	149	12,960	.82	.64	9.60	157.93	40.94
Kanawha	32	12,537	.66	.53	10.11	208.47	52.27
Webster	1	12,300	.91	.74	12.72	140.96	34.68
Virginia Electric & Power Co Mount Storm	**3,336**	**12,168**	**1.59**	**1.31**	**15.86**	**118.91**	**28.94**
Maryland	2,186	12,203	1.55	1.27	15.99	115.36	28.16
Garrett	2,186	12,203	1.55	1.27	15.99	115.36	28.16
Pennsylvania	489	12,205	1.74	1.43	15.25	128.02	31.25
Somerset	489	12,205	1.74	1.43	15.25	128.02	31.25
West Virginia	661	12,025	1.61	1.34	15.87	123.98	29.82
Grant	627	12,028	1.61	1.34	15.79	123.74	29.77
Upshur	34	11,968	1.64	1.37	17.35	128.65	30.79
Virginia Electric & Power Co North Branch	**273**	**10,033**	**2.75**	**2.75**	**29.02**	**96.82**	**19.43**
Maryland	273	10,033	2.75	2.75	29.02	96.82	19.43
Garrett	273	10,033	2.75	2.75	29.02	96.82	19.43
Virginia Electric & Power Co Possum Point	**815**	**12,417**	**.97**	**.78**	**10.90**	**161.66**	**40.15**
Kentucky	135	12,450	1.14	.91	10.67	195.00	48.56
Knott	63	12,191	1.11	.91	12.43	196.15	47.83
Letcher	44	12,666	1.22	.96	10.28	195.34	49.48
Pike	28	12,686	1.07	.84	7.41	192.04	48.72
Virginia	14	13,169	.90	.68	9.35	204.05	53.74
Dickenson	14	13,169	.90	.68	9.35	204.05	53.74
West Virginia	667	12,395	.94	.76	10.98	153.95	38.17
Boone	292	12,640	.88	.70	9.68	141.23	35.70
Greenbrier	7	12,728	.70	.55	10.79	147.71	37.60
Kanawha	131	12,174	.87	.71	11.86	201.79	49.13
Nicholas	9	12,588	.86	.69	10.78	189.53	47.71
Webster	228	12,191	1.08	.88	12.15	142.14	34.66

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Virginia Electric & Power Co Yorktown	**681**	**13,006**	**1.49**	**1.15**	**8.40**	**159.37**	**41.45**
Kentucky	605	13,026	1.52	1.17	7.94	158.80	41.37
Bell	93	12,596	1.65	1.31	9.82	198.37	49.98
Letcher	334	13,256	1.52	1.15	7.01	151.06	40.05
Pike	178	12,817	1.46	1.14	8.68	153.42	39.33
Virginia	54	13,044	1.27	.97	11.75	175.98	45.91
Dickenson	54	13,044	1.27	.97	11.75	175.98	45.91
West Virginia	23	12,404	1.16	.93	12.61	133.84	33.20
Boone	12	12,012	.93	.77	13.38	128.43	30.85
Webster	11	12,825	1.40	1.09	11.78	139.27	35.72
West Penn Power Co Hatfield	**542**	**12,821**	**2.20**	**1.71**	**9.29**	**107.01**	**27.44**
Pennsylvania	349	12,813	2.19	1.71	9.33	106.54	27.30
Armstrong	4	12,910	2.24	1.74	8.40	94.80	24.48
Greene	337	12,809	2.20	1.72	9.38	106.59	27.31
Washington	8	12,927	1.72	1.33	7.70	109.27	28.25
West Virginia	193	12,836	2.20	1.71	9.22	107.88	27.69
Brooke	1	12,752	2.24	1.76	9.70	107.80	27.49
Harrison	54	12,848	2.18	1.70	9.12	107.89	27.72
Marion	34	12,873	2.21	1.72	9.07	108.00	27.81
Marshall	29	12,803	2.22	1.73	9.41	107.86	27.62
Monongalia	75	12,823	2.20	1.71	9.28	107.82	27.65
West Texas Utilities Co Oklaunion	**2,084**	**8,449**	**.35**	**.41**	**5.38**	**133.33**	**22.53**
Wyoming	2,084	8,449	.35	.41	5.38	133.33	22.53
Campbell	2,084	8,449	.35	.41	5.38	133.33	22.53
Western Farmers Elec Coop Inc Hugo	**1,748**	**8,743**	**.28**	**.32**	**4.82**	**108.00**	**18.88**
Wyoming	1,748	8,743	.28	.32	4.82	108.00	18.88
Campbell	1,748	8,743	.28	.32	4.82	108.00	18.88
Wisconsin Electric Power Co Oak Creek	**3,362**	**9,147**	**.28**	**.30**	**4.48**	**100.14**	**18.32**
Pennsylvania	191	13,053	1.54	1.18	7.03	121.04	31.60
Greene	191	13,053	1.54	1.18	7.03	121.04	31.60
Wyoming	3,171	8,912	.20	.23	4.33	98.29	17.52
Campbell	3,090	8,912	.20	.23	4.31	98.48	17.55
Converse	81	8,900	.27	.31	5.06	91.11	16.22
Wisconsin Electric Power Co Pleasant Prairie	**5,373**	**8,472**	**.31**	**.37**	**5.35**	**76.86**	**13.02**
Wyoming	5,373	8,472	.31	.37	5.35	76.86	13.02
Campbell	5,373	8,472	.31	.37	5.35	76.86	13.02
Wisconsin Electric Power Co Port Washington	**499**	**13,095**	**1.43**	**1.09**	**7.62**	**140.15**	**36.70**
Kentucky	58	12,679	1.23	.97	9.90	233.10	59.11
Perry	58	12,679	1.23	.97	9.90	233.10	59.11
Pennsylvania	427	13,157	1.47	1.12	7.27	124.64	32.80
Washington	427	13,157	1.47	1.12	7.27	124.64	32.80
West Virginia	15	12,930	.84	.65	8.84	238.46	61.67
Logan	15	12,930	.84	.65	8.84	238.46	61.67
Wisconsin Electric Power Co Presque Isle	**2,055**	**10,430**	**.44**	**.42**	**6.92**	**132.04**	**27.54**
Colorado	715	12,105	.57	.47	9.80	147.20	35.64
Gunnison	715	12,105	.57	.47	9.80	147.20	35.64
Kentucky	180	12,683	.93	.73	9.85	200.33	50.82
Perry	180	12,683	.93	.73	9.85	200.33	50.82
Montana	523	9,047	.28	.31	4.68	108.04	19.55
Big Horn	523	9,047	.28	.31	4.68	108.04	19.55
Wyoming	637	9,047	.28	.31	4.68	101.90	18.44
Campbell	30	8,754	.33	.38	4.64	119.90	20.99
Converse	607	9,061	.28	.31	4.69	101.05	18.31
Wisconsin Electric Power Co Valley	**578**	**12,044**	**.43**	**.35**	**7.91**	**160.87**	**38.75**
Colorado	578	12,044	.43	.35	7.91	160.87	38.75
Gunnison	578	12,044	.43	.35	7.91	160.87	38.75
Wisconsin Power & Light Co Columbia	**4,537**	**8,560**	**.32**	**.38**	**5.10**	**94.35**	**16.15**

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

Table 24. Origin of Coal Received by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant Origin State County	Quantity (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per million Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Wisconsin Power & Light Co Columbia							
Wyoming	4,537	8,560	0.32	0.38	5.10	94.35	16.15
Campbell	4,537	8,560	.32	.38	5.10	94.35	16.15
Wisconsin Power & Light Co Edgewater	**2,462**	**9,003**	**.32**	**.36**	**5.82**	**119.45**	**21.51**
Utah	151	11,408	.34	.30	7.79	151.35	34.53
Sevier	151	11,408	.34	.30	7.79	151.35	34.53
Virginia	25	14,065	.64	.45	5.31	153.75	43.25
Buchanan	25	14,065	.64	.45	5.31	153.75	43.25
Wyoming	2,286	8,789	.32	.36	5.69	116.11	20.41
Campbell	2,200	8,731	.31	.35	5.67	114.47	19.99
Carbon	74	10,502	.57	.54	6.61	157.36	33.05
Converse	13	8,877	.18	.20	4.56	110.30	19.58
Wisconsin Power & Light Co Nelson Dewey	**482**	**9,323**	**.33**	**.35**	**3.99**	**125.35**	**23.37**
Montana	482	9,323	.33	.35	3.99	125.35	23.37
Big Horn	482	9,323	.33	.35	3.99	125.35	23.37
Wisconsin Public Service Corp Pulliam	**1,576**	**9,012**	**.22**	**.25**	**4.45**	**107.31**	**19.34**
Colorado	12	11,984	.37	.31	5.90	176.80	42.38
Delta	12	11,984	.37	.31	5.90	176.80	42.38
West Virginia	18	13,412	.81	.60	6.32	272.31	73.04
Boone	18	13,412	.81	.60	6.32	272.31	73.04
Wyoming	1,546	8,938	.21	.24	4.42	103.70	18.54
Campbell	1,418	8,949	.21	.24	4.35	103.76	18.57
Converse	128	8,817	.24	.27	5.22	103.11	18.18
Wisconsin Public Service Corp Weston	**1,970**	**8,798**	**.29**	**.33**	**5.50**	**103.03**	**18.13**
Utah	11	10,903	.40	.37	10.50	211.00	46.01
Sevier	11	10,903	.40	.37	10.50	211.00	46.01
Wyoming	1,959	8,786	.29	.33	5.47	102.27	17.97
Campbell	1,959	8,786	.29	.33	5.47	102.27	17.97
Wyandotte Municipal Serv Comm Wyandotte	**127**	**12,512**	**.81**	**.65**	**10.83**	**170.80**	**42.74**
Kentucky	64	12,526	.83	.66	11.31	171.71	43.02
Clay	16	12,486	1.16	.93	12.19	217.71	54.37
Pike	47	12,535	.70	.56	10.88	157.85	39.57
Unknown[1]	1	12,738	1.50	1.18	17.52	86.35	22.00
Ohio	6	12,656	1.93	1.52	7.92	160.70	40.68
Stark	6	12,656	1.93	1.52	7.92	160.70	40.68
Utah	15	12,589	.70	.56	7.23	216.40	54.49
Carbon	15	12,589	.70	.56	7.23	216.40	54.49
West Virginia	41	12,441	.66	.53	11.87	153.71	38.25
Nicholas	41	12,441	.66	.53	11.87	153.71	38.25
Total	**762,815**	**10,019**	**.89**	**.89**	**8.82**	**123.15**	**24.68**

1 Refers to coal in which the county of origin in not known.

2 The cost reported under IMT Transfer (Louisiana) is the weighted average cost of coal delivered to this facility. Florida Power Corporation incurs additional costs for transporting coal from this transfer facility to the Crystal River power plant in Florida. This cost is not included in data shown in this report. When aggregated at the State level, data for this transfer facility are shown as though the coal were delivered to Florida.

3 The Tampa Electric Company reports coal destined for the Big Bend power plant in Florida as it is received at the Davant facility located in Louisiana. The cost reported under Davant Transfer is the weighted average cost of coal delivered to this facility. Tampa Electric incurs additional costs for transporting coal from Davant to the Big Bend plant. These costs are not included in data shown in this report. When aggregated at the State level, data for this transfer facility are shown as though the coal were delivered to Florida.

4 Coal reported as delivered to the Cora and GRT transfer facilities is later transferred to individual electric plants located in Alabama, Kentucky, and Tennessee. The cost of transportation from these facilities to the electric plants is not included in the costs shown in this report. Approximately 97 percent of the coal delivered to the Cora facility was transferred to the Allen plant in Tennessee. About 3 percent was transferred to plants in Alabama. Approximately 80 percent of the coal delivered to the GRT facility was transferred to plants in Tennessee. Approximately 19 percent was transferred to plants in Alabama. Less than 1 percent was transferred to plants in Kentucky.

* = Number less than 0.5.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Fossil-Fuel Data at the Electric Utility and Plant Level

Table 25. The Top 20 Electric Utilities, Ranked by Receipts of Coal, 2001

Electric Utility	Receipts (thousand short tons)	Average Delivered Cost		Total Delivered Cost (million dollars)
		(cents per million Btu)	(dollars per short ton)	
1. Tennessee Valley Authority	36,556	121.92	27.99	1,023.15
2. Georgia Power Co	33,639	166.38	39.06	1,313.94
3. TXU Electric Co	27,297	131.74	18.01	491.74
4. Alabama Power Co	24,211	141.68	30.07	728.00
5. PacifiCorp	22,216	87.36	17.25	383.23
6. Detroit Edison Co	20,185	122.38	25.05	505.59
7. Ameren UE	18,797	98.10	17.28	324.87
8. Duke Power Co	17,395	157.31	38.53	670.23
9. Public Service Co of Indiana	16,542	110.30	24.35	402.81
10. Reliant HL&P	16,423	157.06	24.47	401.93
11. Basin Electric Power Coop	16,275	59.00	8.85	143.95
12. Ohio Power Co	15,598	143.01	34.03	530.79
13. Kansas Power and Light Co	13,942	115.59	20.09	280.03
14. MidAmerican Energy	13,607	74.96	12.90	175.50
15. Northern States Power Co	13,255	94.62	16.70	221.36
16. Arkansas Power and Light Co	12,681	78.54	13.74	174.20
17. Indiana Michigan Power	11,904	117.41	22.71	270.30
18. Southwestern Electric Power	11,883	150.44	24.11	286.51
19. Wisconsin Electric Power Co	11,868	102.91	19.29	228.91
20. Appalachian Power Co	11,858	129.66	31.09	368.64

Note: Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 26. The Top 20 Electric Utilities, Ranked by Receipts of Petroleum, 2001

Electric Utility	Receipts (thousand barrels)	Average Delivered Cost		Total Delivered Cost (million dollars)
		(cents per million Btu)	(dollars per barrel)	
1. Florida Power and Light Co	41,026	361.69	23.05	945.60
2. Florida Power Corp	10,739	335.68	21.64	232.38
3. Long Island Lighting Co	10,346	341.99	21.92	226.79
4. Hawaiian Electric Co Inc	10,262	490.34	30.80	316.05
5. Mississippi Power & Light	8,369	375.49	24.45	204.62
6. Virginia Electric and Power	7,328	357.88	22.59	165.53
7. Jacksonville Electric Auth	4,099	337.25	21.48	88.02
8. Power Auth State of NY	2,736	416.89	26.01	71.16
9. Louisiana Power & Light Co	1,454	524.03	33.29	48.41
10. Tampa Electric Power Co	1,344	475.50	29.62	39.82
11. Consumers Power Co	1,235	375.81	23.75	29.33
12. Kansas Gas and Electric Co	1,180	316.99	20.95	24.71
13. Consolidated Edison Co-NY Inc	1,157	397.95	25.00	28.92
14. Detroit Edison Co	970	493.35	29.68	28.77
15. TXU Electric Co	945	687.85	40.02	37.82
16. Public Serv Co of NH	934	336.71	21.56	20.14
17. Central Hudson Gas and Elec Corp	925	190.81	12.12	11.22
18. Central Power & Light Co	791	667.25	39.88	31.53
19. Philadelphia Electric Co	637	372.62	23.40	14.91
20. New Orleans Public Service Inc	580	436.47	28.50	16.53

Note: Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 27. The Top 20 Electric Utilities, Ranked by Receipts of Gas, 2001

Electric Utility	Receipts (thousand Mcf)	Average Delivered Cost		Total Delivered Cost (million dollars)
		(cents per million Btu)	(dollars per Mcf)	
1. TXU Electric Co	273,845	425.09	4.36	1,194.38
2. Florida Power and Light Co	213,005	458.25	4.78	1,018.85
3. Reliant HL&P	181,033	423.17	4.32	782.47
4. Gulf States Utilities Co	174,783	416.57	4.34	758.22
5. Louisiana Power & Light Co	100,794	398.03	4.13	416.52
6. Central Power & Light Co	81,499	409.83	4.21	343.43
7. Southwestern Public Service	71,543	415.44	4.20	300.77
8. Public Service Co of Oklahoma	70,207	423.22	4.34	304.60
9. Oklahoma Gas & Electric Co	64,329	477.26	4.95	318.37
10. Long Island Lighting Co	62,146	379.11	3.85	239.55
11. San Antonio City Pub Service	43,200	408.86	4.17	180.28
12. Portland General Electric Co	43,147	374.91	3.82	165.00
13. Los Angeles Dept of Wtr and Pwr	41,175	1,166.95	11.88	489.18
14. Mississippi Power & Light	39,722	351.07	3.61	143.35
15. Public Service Co of Colorado	34,601	369.82	3.77	130.36
16. Nevada Power Co	34,540	867.83	8.88	306.89
17. Southwestern Electric Power	33,966	416.66	4.34	147.37
18. Salt River Proj Ag I & P Dist	32,285	422.88	4.30	138.83
19. El Paso Electric	30,728	415.31	4.25	130.52
20. West Texas Utilities Co	30,371	415.83	4.22	128.06

Notes: • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Mcf = thousand cubic feet.

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

Table 28. Receipts of Petroleum Coke by Electric Utility, 2001

Electric Utility	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Ameren UE	197	14,303	3.72	0.40	66.85	19.12
Central Elec Power Coop-Missouri[1]	*	14,235	3.20	.56	52.82	15.04
Jacksonville Electric Auth	568	14,255	6.28	.30	62.63	17.85
Lakeland City of	18	13,955	4.19	.44	127.02	35.45
Manitowoc Public Utilities	36	14,234	5.51	.65	54.73	15.58
Michigan South Central Power	*	14,002	4.65	.43	150.01	42.01
Northern States Power Co	201	13,613	5.64	.70	39.12	10.65
Northern Indiana Pub Serv Co	149	13,927	4.34	.20	69.32	19.31
Reliant HL&P	132	13,609	1.66	.44	156.57	42.61
Salt River Proj Ag I & P Dist	17	14,500	3.67	.60	100.48	29.14
Seminole Electric Coop	182	14,394	5.88	.41	110.74	31.88
Tampa Electric Power Co	303	13,945	4.90	.46	82.67	23.06
Wisconsin Power & Light	71	13,920	5.70	.66	96.25	26.80
Wisconsin Electric Power Co	145	14,201	5.24	.20	87.79	24.93
Total	**2,019**	**14,079**	**5.13**	**.40**	**78.38**	**22.07**

1 Includes a small amount of coal.

* = Number less than 0.5.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Table 29. Receipts of No. 6 Fuel Oil by Electric Utility, 2001

Company	Receipts (thousand barrels)	Average Quality		Average Delivered Cost	
		Btu (per gallon)	Sulfur (percent by weight)	(cents per million Btu)	(dollars per barrel)
Ameren CIPS	111	151,484	0.29	537.20	34.18
Central Hudson Gas and Elec Corp	925	151,272	.99	190.81	12.12
Consolidated Edison Co-NY Inc	1,157	149,565	.28	397.95	25.00
Consumers Power Co	1,100	154,178	1.44	350.38	22.69
Delmarva Power & Light	201	152,866	.81	388.10	24.92
Detroit Edison Co	571	146,600	.74	442.02	27.22
Dover City of	269	152,330	.78	374.18	23.94
Florida Power and Light Co	40,828	151,793	1.11	360.78	23.00
Florida Power Corp	10,606	153,673	1.46	333.42	21.52
Gainesville Regional Utilities	96	150,392	1.42	478.32	30.21
Hawaiian Electric Co Inc	10,228	149,586	.46	489.78	30.77
Jacksonville Electric Auth	4,047	151,778	1.46	334.61	21.33
Kansas Gas and Electric Co	1,180	157,372	1.70	316.99	20.95
Kansas Power and Light Co	267	158,847	1.70	334.97	22.35
Lake Worth City of	9	149,356	1.37	561.00	35.19
Lakeland City of	189	149,663	1.82	425.30	26.73
Long Island Lighting Co	10,346	152,610	.78	341.99	21.92
Louisiana Power & Light Co	1,014	154,163	.50	510.14	33.03
Mississippi Power & Light	8,348	155,067	3.00	374.94	24.42
New Orleans Public Service Inc	579	155,481	1.50	436.12	28.48
Orlando Utilities Comm	5	152,500	1.00	430.26	27.56
Pacific Gas and Electric	369	148,800	1.10	594.98	37.18
Philadelphia Electric Co	540	151,375	.52	331.85	21.10
Power Auth State of NY	2,665	148,743	.21	414.66	25.90
Public Serv Co of NH	902	153,000	.83	329.07	21.15
Tampa Electric Power Co	1,023	151,569	.95	446.20	28.40
Taunton City of	86	150,259	.46	420.13	26.51
Vero Beach City of	336	144,624	.59	670.36	40.72
Vineland City of	41	156,400	.77	392.65	25.79
Virginia Electric and Power	6,754	151,157	1.10	337.72	21.44
Total	**104,791**	**152,053**	**1.18**	**371.78**	**23.74**

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Alabama Electric Coop Inc	**1,145**	**11,728**	**1.08**	**8.60**	**139.30**	**32.68**	**351**	**11,934**	**1.79**	**11.38**	**137.70**	**32.87**
Lowman (AL)	1,145	11,728	1.08	8.60	139.30	32.68	351	11,934	1.79	11.38	137.70	32.87
Alabama Power Co	**23,610**	**10,581**	**.70**	**8.28**	**140.86**	**29.81**	**601**	**11,799**	**.75**	**5.06**	**170.61**	**40.26**
Barry (AL)	3,326	11,893	.73	8.30	173.97	41.38	601	11,799	.75	5.06	170.61	40.26
Gadsden (AL)	255	12,168	1.59	13.73	158.19	38.50	—	—	—	—	—	—
Gorgas 2 and 3 (AL)	2,675	12,171	.90	13.09	197.59	48.10	—	—	—	—	—	—
Greene (AL)	1,350	11,978	1.51	8.75	126.49	30.30	—	—	—	—	—	—
Gaston (AL)	5,219	12,175	1.23	12.50	139.37	33.94	—	—	—	—	—	—
James Miller (AL)	10,784	8,799	.26	4.84	110.46	19.44	—	—	—	—	—	—
Ameren CIPS	**2,269**	**10,320**	**1.05**	**8.01**	**128.36**	**26.49**	**4,345**	**9,146**	**.68**	**5.68**	**114.19**	**20.89**
Coffeen (IL)	1,817	10,300	1.00	8.00	124.96	25.74	198	10,113	2.41	8.41	145.98	29.53
Hutsonville (IL)	—	—	—	—	—	—	320	11,355	2.90	9.02	112.84	25.63
Meredosia (IL)	452	10,398	1.26	8.03	141.89	29.51	222	10,984	2.94	10.27	131.61	28.91
Newton (IL)	—	—	—	—	—	—	3,605	8,784	.25	4.95	111.00	19.50
Ameren-UE	**10,893**	**8,920**	**.37**	**5.44**	**97.45**	**17.39**	**7,904**	**8,655**	**.56**	**5.56**	**99.02**	**17.14**
Labadie (MO)	5,904	8,800	.26	5.14	95.08	16.73	3,380	8,605	.37	5.38	99.91	17.20
Meramec (MO)	1,878	9,533	.88	6.47	110.04	20.98	106	11,700	1.29	7.20	126.69	29.65
Sioux (MO)	2,679	8,835	.25	5.30	93.40	16.50	321	11,839	2.53	7.81	124.71	29.53
Rush Island (MO)	432	8,420	.43	5.77	95.75	16.12	4,097	8,368	.54	5.50	94.42	15.80
American Municipal Power Ohio	**191**	**11,789**	**1.91**	**14.64**	**122.36**	**28.85**	**566**	**11,809**	**1.93**	**14.49**	**119.76**	**28.29**
Gorsuch (OH)	191	11,789	1.91	14.64	122.36	28.85	566	11,809	1.93	14.49	119.76	28.29
Ames, City of	**228**	**8,863**	**.20**	**4.34**	**144.34**	**25.59**	—	—	—	—	—	—
Ames (IA)	228	8,863	.20	4.34	144.34	25.59	—	—	—	—	—	—
Appalachian Power	**9,397**	**11,914**	**.71**	**11.98**	**132.71**	**31.62**	**2,461**	**12,270**	**.76**	**11.98**	**118.36**	**29.05**
Clinch River (VA)	1,375	12,300	.68	15.00	138.20	34.00	466	12,492	.71	12.84	144.96	36.22
Glen Lyn (VA)	329	12,763	.87	10.51	146.80	37.47	290	12,827	.86	10.20	147.83	37.92
Amos (WV)	4,505	12,003	.77	11.91	129.98	31.20	1,044	12,107	.78	12.00	103.33	25.02
Kanawha River (WV)	645	12,045	.76	13.01	111.44	26.85	493	12,172	.77	12.28	97.95	23.85
Mountaineer (WV)	2,543	11,405	.58	10.40	138.25	31.54	168	11,997	.66	11.75	142.05	34.08
Arizona Electric Power Coop Inc	**1,326**	**9,612**	**.72**	**14.16**	**143.00**	**27.49**	**78**	**9,934**	**.43**	**13.71**	**159.00**	**31.59**
Apache (AZ)	1,326	9,612	.72	14.16	143.00	27.49	78	9,934	.43	13.71	159.00	31.59
Arizona Public Service	**6,624**	**9,248**	**.65**	**18.75**	**103.47**	**19.14**	**802**	**9,546**	**.56**	**12.11**	**123.94**	**23.66**
Cholla (AZ)	1,732	9,862	.45	14.27	113.91	22.47	802	9,546	.56	12.11	123.94	23.66
Four Corners (NM)	4,892	9,030	.72	20.34	99.44	17.96	—	—	—	—	—	—
Arkansas Power and Light	**11,991**	**8,762**	**.26**	**4.56**	**73.95**	**12.96**	**690**	**8,450**	**.36**	**4.91**	**161.29**	**27.26**
Whitebluff (AR)	5,419	8,506	.34	4.99	79.91	13.59	690	8,450	.36	4.91	161.29	27.26
Independence (AR)	6,573	8,972	.20	4.21	69.30	12.43	—	—	—	—	—	—
Associated Electric Coop	**9,554**	**8,910**	**.20**	**4.26**	**89.37**	**15.93**	—	—	—	—	—	—
Madrid (MO)	4,428	8,913	.20	4.26	100.22	17.86	—	—	—	—	—	—
Hill (MO)	5,126	8,908	.20	4.26	80.00	14.25	—	—	—	—	—	—
Atlantic City Electric	**40**	**12,972**	**2.30**	**9.70**	**171.57**	**44.51**	**147**	**12,828**	**1.49**	**9.41**	**250.30**	**64.21**
England (NJ)	40	12,972	2.30	9.70	171.57	44.51	79	13,191	2.13	7.71	238.17	62.84
Deepwater (NJ)	—	—	—	—	—	—	68	12,409	.75	11.37	265.14	65.80
Basin Electric Power Coop	**16,275**	**7,496**	**.50**	**7.12**	**59.00**	**8.85**	—	—	—	—	—	—
Leland Olds (ND)	3,648	6,841	.69	8.24	76.33	10.44	—	—	—	—	—	—
Laramie River (WY)	7,740	8,376	.31	5.18	46.73	7.83	—	—	—	—	—	—
Antelope Valley (ND)	4,887	6,592	.66	9.38	70.28	9.26	—	—	—	—	—	—
Big Rivers Electric Corp	**265**	**11,858**	**3.23**	**11.19**	**90.30**	**21.42**	—	—	—	—	—	—
Reid-Henderson (KY)	265	11,858	3.23	11.19	90.30	21.42	—	—	—	—	—	—
Black Hills Corporation	**538**	**8,091**	**.62**	**7.05**	**46.84**	**7.58**	—	—	—	—	—	—
Neal Simpson II (WY)	538	8,091	.62	7.05	46.84	7.58	—	—	—	—	—	—
Cardinal Operating Co (AEP)	**2,894**	**11,926**	**1.16**	**12.20**	**152.76**	**36.44**	**1,409**	**12,069**	**1.64**	**10.24**	**119.36**	**28.81**
Cardinal (OH)	2,894	11,926	1.16	12.20	152.76	36.44	1,409	12,069	1.64	10.24	119.36	28.81

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Carolina Power and Light	7,946	12,380	0.83	11.08	161.78	40.06	1,438	12,557	0.94	10.12	179.59	45.10
Asheville (NC)	526	12,681	.84	10.39	167.17	42.40	186	12,878	1.16	9.57	182.69	47.05
Cape Fear (NC)	428	12,423	.90	10.50	152.46	37.88	59	12,620	1.14	11.85	168.62	42.56
Lee (NC)	694	12,439	.90	10.70	157.52	39.19	8	13,049	1.09	9.20	187.00	48.80
Roxboro (NC)	4,257	12,338	.80	11.39	160.92	39.71	666	12,549	.92	10.16	176.14	44.21
Sutton (NC)	458	12,658	1.08	9.26	163.23	41.32	244	12,281	.90	10.03	191.79	47.11
Weatherspoon (NC)	231	12,716	1.11	8.87	179.64	45.69	46	12,772	1.06	8.66	165.25	42.21
Robinson (SC)	204	12,745	1.20	8.90	164.58	41.95	58	12,436	1.16	11.06	197.73	49.18
Mayo (NC)	1,146	12,106	.63	12.22	163.75	39.65	171	12,569	.67	10.18	173.92	43.72
Cedar Falls Utilities	—	—	—	—	—	—	38	12,334	1.41	7.47	194.72	48.03
Streeter (IA)	—	—	—	—	—	—	38	12,334	1.41	7.47	194.72	48.03
Central Elec Power Coop-Missouri	—	—	—	—	—	—	308	9,530	.77	5.31	116.75	22.25
Chamois (MO)	—	—	—	—	—	—	308	9,530	.77	5.31	116.75	22.25
Central Hudson Gas and Electric	37	13,309	.61	7.27	156.10	41.55	—	—	—	—	—	—
Danskammer (NY)	37	13,309	.61	7.27	156.10	41.55	—	—	—	—	—	—
Central Illinois Light	1,683	10,857	2.47	7.72	178.92	38.85	689	11,633	1.51	7.60	201.97	46.99
Edwards (IL)	721	11,154	1.18	7.31	122.78	27.39	678	11,652	1.49	7.57	202.59	47.21
Duck Creek (IL)	962	10,635	3.45	8.02	223.06	47.44	11	10,402	3.25	9.39	157.01	32.67
Central Iowa Power Coop	—	—	—	—	—	—	180	11,243	2.94	10.49	116.87	26.28
Fair Station (IA)	—	—	—	—	—	—	180	11,243	2.94	10.49	116.87	26.28
Central Louisiana Electric	5,602	7,482	.90	10.90	139.94	20.94	—	—	—	—	—	—
Dolet Hills (LA)	3,754	6,839	1.15	13.66	141.66	19.38	—	—	—	—	—	—
Rodemacher (LA)	1,848	8,788	.41	5.28	137.21	24.12	—	—	—	—	—	—
Central Operating Co (AEP)	669	12,062	.78	12.38	129.79	31.31	1,808	12,068	1.00	12.28	128.12	30.92
Sporn (WV)	669	12,062	.78	12.38	129.79	31.31	1,808	12,068	1.00	12.28	128.12	30.92
Central Power and Light	794	10,469	.35	5.87	141.63	29.65	901	9,408	.32	6.00	136.07	25.60
Coleto Creek (TX)	794	10,469	.35	5.87	141.63	29.65	901	9,408	.32	6.00	136.07	25.60
Cincinnati Gas and Electric Co	8,099	12,126	2.50	10.61	111.03	26.93	2,860	11,785	1.47	13.02	135.83	32.01
Beckjord (OH)	1,606	11,860	1.16	12.45	120.46	28.57	1,070	11,747	1.09	13.64	141.87	33.33
Miami Fort (OH)	1,864	12,280	1.64	11.00	115.15	28.28	942	11,834	1.10	13.45	137.72	32.60
East Bend (KY)	1,163	12,228	2.61	10.50	104.29	25.51	562	11,756	2.17	11.30	127.45	29.97
Zimmer (OH)	3,466	12,131	3.55	9.58	106.80	25.91	286	11,820	2.75	12.65	123.52	29.20
City of Independence Pwr and Lt	80	10,851	2.71	12.94	162.11	35.18	29	12,364	2.81	8.99	203.60	50.34
Blue Valley (MO)	80	10,851	2.71	12.94	162.11	35.18	29	12,364	2.81	8.99	203.60	50.34
City Public Service-San Antonio	5,938	8,447	.32	5.45	101.01	17.07	—	—	—	—	—	—
JT Deely/Spruce (TX)	5,938	8,447	.32	5.45	101.01	17.07	—	—	—	—	—	—
City Utilities of Springfield	1,756	9,226	.29	4.46	117.94	21.76	—	—	—	—	—	—
James River (MO)	939	9,507	.37	4.61	123.88	23.55	—	—	—	—	—	—
Southwest (MO)	817	8,904	.20	4.29	110.65	19.70	—	—	—	—	—	—
Colorado Springs Dept Pub Utils	1,795	9,891	.37	6.74	82.82	16.38	162	9,367	.33	6.34	97.47	18.26
Drake (CO)	961	10,503	.46	8.06	88.63	18.62	26	11,191	.52	9.52	116.35	26.04
Nixon (CO)	834	9,186	.26	5.22	75.17	13.81	137	9,023	.30	5.74	93.05	16.79
Columbia Water and Light	30	13,408	1.10	6.13	206.58	55.40	—	—	—	—	—	—
Columbia (MO)	30	13,408	1.10	6.13	206.58	55.40	—	—	—	—	—	—
Columbus Southern Power Co (AEP)	3,400	11,709	2.33	9.12	133.06	31.16	645	11,487	2.75	11.83	110.48	25.38
Conesville (OH)	3,400	11,709	2.33	9.12	133.06	31.16	448	11,468	2.76	13.18	109.82	25.19
Picway (OH)	—	—	—	—	—	—	196	11,532	2.71	8.74	111.97	25.83
Consumers Power	6,383	10,415	.52	8.19	138.01	28.75	2,634	9,151	.35	5.45	122.98	22.51
Cobb (MI)	597	9,254	.51	6.96	121.37	22.46	459	9,548	.59	6.79	131.42	25.10
Karn-Weadock (MI)	546	8,829	.27	5.24	108.48	19.16	676	8,791	.25	4.74	107.96	18.98
Campbell (MI)	3,216	10,686	.53	8.34	145.07	31.00	814	9,066	.27	4.96	117.65	21.33

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Consumers Power												
Weadock (MI)	1,193	11,191	0.66	9.82	142.53	31.90	529	9,355	0.37	5.78	134.99	25.26
Whiting (MI)	832	10,125	.50	8.07	129.82	26.29	155	9,291	.42	6.04	145.34	27.01
Cooperative Power Association	7,670	6,198	.61	11.27	75.17	9.32	—	—	—	—	—	—
Coal Creek (ND)	7,670	6,198	.61	11.27	75.17	9.32	—	—	—	—	—	—
Dairyland Power Cooperative	2,320	9,620	.50	4.72	115.35	22.19	206	12,466	1.16	7.19	181.42	45.23
Alma-Madgett (WI)	1,643	9,154	.32	4.48	107.02	19.59	48	12,470	1.33	8.38	177.01	44.15
Genoa No.3 (WI)	677	10,750	.93	5.32	132.57	28.50	158	12,464	1.11	6.83	182.76	45.56
Dayton Power and Light Co	4,987	11,530	.79	15.01	112.28	25.89	2,889	11,736	.89	13.04	158.62	37.23
Hutchings (OH)	—	—	—	—	—	—	471	12,377	.81	11.34	178.08	44.08
Stuart (OH)	3,562	11,455	.85	15.32	107.34	24.59	2,162	11,585	.94	13.43	152.28	35.28
Killen (OH)	1,425	11,719	.65	14.25	124.35	29.15	255	11,827	.66	12.88	173.73	41.09
Delmarva Power and Light	14	12,642	.69	12.50	195.00	49.30	10	12,473	.65	10.23	248.18	61.91
Edgemoor (DE)	14	12,642	.69	12.50	195.00	49.30	10	12,473	.65	10.23	248.18	61.91
Deseret Generation & Trans	2,028	9,929	.40	10.15	156.72	31.12	—	—	—	—	—	—
Bonanza (UT)	2,028	9,929	.40	10.15	156.72	31.12	—	—	—	—	—	—
Detroit Edison Co	17,080	10,168	.54	5.34	122.00	24.81	3,105	10,595	.91	6.41	124.39	26.36
Harbor Beach (MI)	101	13,085	.97	7.21	135.77	35.53	—	—	—	—	—	—
Marysville (MI)	31	13,087	.95	7.11	141.07	36.92	1	12,946	.74	6.20	140.70	36.43
Monroe (MI)	7,012	10,578	.66	6.30	115.82	24.50	1,784	10,011	.53	6.29	127.35	25.50
River Rouge (MI)	871	10,983	.58	6.49	123.46	27.12	303	10,115	.46	7.12	135.50	27.41
St Clair (MI)	3,918	9,488	.35	4.19	128.32	24.35	745	12,638	2.18	6.94	116.21	29.37
Trenton Channel (MI)	1,901	10,594	.72	5.42	112.24	23.78	170	9,357	.45	5.48	124.39	23.28
Belle River (MI)	3,246	9,516	.35	4.22	134.29	25.56	102	9,339	.36	4.08	113.60	21.22
Duke Power	12,239	12,243	.83	11.84	145.85	35.71	5,156	12,255	.97	11.56	184.49	45.22
Allen (NC)	1,466	12,114	.82	11.96	150.75	36.52	707	12,142	1.03	12.19	190.45	46.25
Buck (NC)	440	11,749	.67	15.82	142.42	33.47	284	11,648	.75	16.88	174.45	40.64
Cliffside (NC)	1,131	12,476	.94	9.34	142.63	35.59	553	12,558	1.04	9.55	188.77	47.41
Dan River (NC)	117	12,775	.69	9.88	147.77	37.76	91	12,873	.59	9.30	178.09	45.85
Marshall (NC)	3,664	12,297	.81	11.29	143.87	35.38	1,764	12,292	.98	10.96	185.08	45.50
Riverbend (NC)	319	12,056	.97	13.58	149.48	36.04	860	12,129	.98	11.90	167.86	40.72
Lee (SC)	200	12,076	.82	12.45	152.10	36.74	372	12,166	.93	12.36	195.41	47.55
Belews Creek (NC)	4,902	12,238	.84	12.33	146.41	35.83	525	12,457	1.01	11.23	195.41	48.69
East Kentucky Power Coop	1,511	12,019	.78	11.79	123.38	29.66	2,549	12,150	1.03	11.38	140.56	34.16
Cooper (KY)	106	12,473	1.05	10.41	128.91	32.16	825	12,309	1.37	10.31	131.66	32.41
Dale (KY)	411	12,310	.76	10.22	125.48	30.89	153	12,165	.91	9.35	139.18	33.86
Spurlock (KY)	994	11,851	.76	12.59	121.86	28.88	1,571	12,065	.86	12.14	145.46	35.10
Electric Energy	5,057	8,841	.23	4.75	86.91	15.37	56	8,726	.27	4.95	86.32	15.07
Joppa (IL)	5,057	8,841	.23	4.75	86.91	15.37	56	8,726	.27	4.95	86.32	15.07
Empire Dist Electric	517	9,358	.32	4.72	113.07	21.16	24	12,399	.47	7.78	145.50	36.08
Riverton (KS)	150	9,301	.53	4.71	120.31	22.38	—	—	—	—	—	—
Asbury (MO)	367	9,381	.23	4.72	110.15	20.67	24	12,399	.47	7.78	145.50	36.08
Florida Power Corp[1]	2,527	12,664	.89	9.06	184.09	46.63	2,911	12,319	.73	10.58	214.38	52.82
Crystal River (FL)	2,351	12,689	.91	8.97	183.00	46.44	685	12,590	.91	9.91	250.43	63.06
IMT Transfer (LA)	176	12,326	.68	10.32	199.17	49.10	2,226	12,235	.68	10.79	202.97	49.67
Fremont Dept of Public Utilities	323	8,940	.23	4.53	98.20	17.56	—	—	—	—	—	—
Wright (NE)	323	8,940	.23	4.53	98.20	17.56	—	—	—	—	—	—
Gainesville Regional Utilities	462	13,054	.70	7.11	194.44	50.76	—	—	—	—	—	—
Deerhaven (FL)	462	13,054	.70	7.11	194.44	50.76	—	—	—	—	—	—
Georgia Power	17,966	12,566	.87	10.21	164.80	41.42	15,673	10,789	.75	9.10	168.50	36.36
Arkwright (GA)	21	12,599	2.19	10.84	153.10	38.58	163	12,796	2.10	10.76	158.35	40.52
Atkinson-Mcdonough (GA)	1,226	12,758	1.08	8.70	141.89	36.21	41	12,842	1.04	9.20	172.07	44.20
Bowen (GA)	5,035	12,503	1.01	10.01	148.77	37.20	3,573	11,924	.96	13.17	167.93	40.05
Hammond (GA)	1,561	12,749	.80	10.11	146.87	37.45	348	12,806	.87	9.46	149.12	38.19

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Georgia Power												
Harllee Branch (GA)	1,841	12,457	1.01	10.39	172.13	42.88	1,674	12,528	1.09	10.27	188.50	47.23
Mitchell (GA)	161	12,725	1.00	8.85	183.37	46.67	41	12,779	1.15	9.38	211.78	54.13
Yates (GA)	1,217	12,573	.79	11.27	153.31	38.55	1,518	12,641	1.35	11.11	171.10	43.26
Wansley (GA)	3,245	12,609	.81	11.17	155.00	39.09	1,432	11,993	1.12	12.93	180.92	43.40
Scherer (GA)	3,658	12,516	.66	9.80	210.60	52.72	6,881	8,944	.30	5.39	159.16	28.47
Grand Haven Light & Power	—	—	—	—	—	—	205	12,762	2.35	10.07	133.29	34.02
J B Simms (MI)	—	—	—	—	—	—	205	12,762	2.35	10.07	133.29	34.02
Grand Island Utilities	449	8,784	.29	5.44	72.20	12.68	—	—	—	—	—	—
Platte (NE)	449	8,784	.29	5.44	72.20	12.68	—	—	—	—	—	—
Grand River Dam Authority	3,489	8,445	.34	5.22	88.60	14.96	—	—	—	—	—	—
GRDA No 1 (OK)	3,489	8,445	.34	5.22	88.60	14.96	—	—	—	—	—	—
Gulf Power	1,352	12,137	1.07	6.41	157.27	38.18	1,961	12,177	.98	6.84	163.88	39.91
Crist (FL)	990	12,059	1.09	5.98	156.32	37.70	1,119	12,086	1.14	7.00	158.32	38.27
Scholtz (FL)	160	12,709	.93	9.46	159.64	40.58	—	—	—	—	—	—
Smith (FL)	201	12,067	1.09	6.10	159.91	38.59	842	12,298	.77	6.63	171.14	42.09
Gulf States Utilities	2,511	8,784	.38	5.22	113.69	19.97	—	—	—	—	—	—
Nelson (LA)	2,511	8,784	.38	5.22	113.69	19.97	—	—	—	—	—	—
Hamilton, City of	150	12,160	.98	12.52	147.52	35.88	—	—	—	—	—	—
Hamilton (OH)	150	12,160	.98	12.52	147.52	35.88	—	—	—	—	—	—
Hastings Utilities	320	8,764	.29	5.62	67.29	11.79	12	8,740	.29	6.00	67.50	11.80
Hastings (NE)	320	8,764	.29	5.62	67.29	11.79	12	8,740	.29	6.00	67.50	11.80
Holland Board of Public Wks	114	12,850	.84	8.41	164.45	42.27	32	11,494	.92	7.65	190.00	43.68
James De Young (MI)	114	12,850	.84	8.41	164.45	42.27	32	11,494	.92	7.65	190.00	43.68
Hoosier Energy R E C	3,736	11,154	2.82	9.94	102.93	22.96	—	—	—	—	—	—
Frank E Ratts (IN)	709	11,193	1.36	8.84	104.62	23.42	—	—	—	—	—	—
Merom (IN)	3,027	11,145	3.16	10.20	102.53	22.86	—	—	—	—	—	—
Houston Lighting and Power	16,423	7,791	.74	9.81	157.06	24.47	—	—	—	—	—	—
Limestone (TX)	7,169	6,756	1.20	15.67	127.07	17.17	—	—	—	—	—	—
Parish (TX)	9,254	8,593	.38	5.28	175.32	30.13	—	—	—	—	—	—
Indiana Michigan Power	9,678	9,267	.50	5.43	110.96	20.57	2,226	11,422	.70	9.50	140.13	32.01
Tanners Creek (IN)	1,633	11,501	1.61	9.19	112.00	25.76	822	12,242	.83	11.01	123.09	30.14
Rockport (IN)	8,045	8,814	.27	4.67	110.69	19.51	1,404	10,941	.62	8.63	151.29	33.11
Indiana-Kentucky Electric Corp	3,290	9,903	.32	4.90	122.58	24.28	572	11,879	2.01	8.70	125.99	29.93
Clifty Creek (IN)	3,290	9,903	.32	4.90	122.58	24.28	572	11,879	2.01	8.70	125.99	29.93
Indianapolis Power and Light	3,600	11,129	1.99	8.57	97.11	21.62	580	11,094	2.08	9.37	99.85	22.15
Stout (IN)	986	10,883	1.16	8.89	110.58	24.07	246	10,910	1.22	9.21	115.09	25.11
Pritchard (IN)	786	11,296	1.21	7.20	109.57	24.75	5	10,926	1.14	8.89	103.50	22.62
Petersburg (IN)	1,828	11,190	2.78	8.99	84.65	18.94	329	11,234	2.75	9.50	88.72	19.93
Interstate Power	155	12,044	.59	7.72	149.31	35.97	1,530	8,779	.31	5.53	77.84	13.67
Dubuque (IA)	145	12,049	.59	7.67	149.08	35.92	59	10,806	.50	5.72	133.75	28.91
Lansing (IA)	10	11,978	.54	8.33	152.60	36.56	801	8,666	.31	5.52	80.37	13.93
Kapp (IA)	—	—	—	—	—	—	669	8,736	.30	5.52	68.76	12.01
IES Utilities	886	8,507	.33	5.75	106.46	18.11	4,396	8,632	.34	5.58	86.08	14.86
6th St (IA)	24	12,159	.54	8.16	133.05	32.36	214	11,114	.34	7.20	133.07	29.58
Praire Creek (IA)	—	—	—	—	—	—	763	8,550	.31	5.66	86.08	14.72
Sutherland (IA)	—	—	—	—	—	—	570	9,102	.35	5.70	81.13	14.77
Burlington (IA)	—	—	—	—	—	—	757	8,320	.36	5.49	85.13	14.17
Ottumwa (IA)	861	8,404	.33	5.68	105.37	17.71	2,093	8,394	.34	5.39	81.54	13.69
Jacksonville Electric Authority	2,626	12,128	.92	12.24	159.70	38.74	847	12,407	1.21	7.21	162.63	40.36
St Johns River (FL)	2,626	12,128	.92	12.24	159.70	38.74	810	12,421	1.15	7.07	159.51	39.63
Northside (FL)	—	—	—	—	—	—	38	12,114	2.37	10.08	231.10	55.99

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Jamestown Bd of Public Utilities	1	12,733	1.20	9.80	195.00	49.66	75	12,571	1.83	10.77	143.56	36.09
Samuel A Carlson (NY)	1	12,733	1.20	9.80	195.00	49.66	75	12,571	1.83	10.77	143.56	36.09
Kansas City Bd Public Utilities	1,572	8,290	.36	5.21	80.43	13.34	—	—	—	—	—	—
Quindaro (KS)	503	8,810	.29	5.37	97.18	17.12	—	—	—	—	—	—
Nearman (KS)	1,069	8,045	.39	5.14	71.80	11.55	—	—	—	—	—	—
Kansas City Power and Light	4,542	8,781	.34	5.71	75.32	13.23	4,903	8,836	.62	6.14	85.26	15.07
La Cygne (KS)	1,771	8,810	.38	5.83	79.83	14.07	2,488	8,914	.88	7.05	76.43	13.62
Hawthorne (MO)	—	—	—	—	—	—	841	8,713	.30	5.36	109.65	19.11
Montrose (MO)	292	8,794	.40	5.66	90.54	15.92	1,559	8,782	.38	5.12	86.79	15.24
Iatan (MO)	2,479	8,758	.30	5.63	70.28	12.31	15	8,521	.31	4.71	55.70	9.49
Kansas Power and Light Co	11,730	8,425	.37	4.89	112.67	18.98	2,212	10,087	.38	7.36	128.52	25.93
Lawrence (KS)	402	8,780	.31	5.30	162.67	28.56	1,532	10,156	.39	7.44	130.45	26.50
Tecumseh (KS)	150	8,777	.31	5.32	159.82	28.05	680	9,931	.37	7.17	124.07	24.64
Jeffrey Energy Cnt (KS)	11,178	8,407	.37	4.87	110.13	18.52	—	—	—	—	—	—
Kentucky Power (AEP)	851	12,161	.94	9.71	104.70	25.47	2,385	11,929	.92	10.83	102.05	24.35
Big Sandy (KY)	851	12,161	.94	9.71	104.70	25.47	2,385	11,929	.92	10.83	102.05	24.35
Kentucky Utilities	4,445	11,914	1.85	12.48	107.46	25.60	3,113	10,975	.82	9.37	136.03	29.86
Brown (KY)	886	11,961	1.50	12.79	127.05	30.39	673	12,106	1.63	12.54	127.89	30.96
Ghent (KY)	3,213	11,959	1.93	12.45	101.00	24.16	2,200	10,445	.50	8.43	139.97	29.24
Green River (KY)	346	11,369	2.02	11.89	117.70	26.76	107	12,203	2.10	10.55	136.85	33.40
Tyrone (KY)	—	—	—	—	—	—	133	13,039	.80	7.90	121.50	31.68
Lakeland Dept of Elec Wtr Utils	107	12,703	1.31	9.42	164.35	41.75	223	12,395	1.00	8.98	197.50	48.96
Plant 3-Mcintosh (FL)	107	12,703	1.31	9.42	164.35	41.75	223	12,395	1.00	8.98	197.50	48.96
Lansing Board of Water and Light	1,364	9,848	.47	6.74	134.67	26.52	—	—	—	—	—	—
Eckert (MI)	1,046	9,016	.34	5.88	120.24	21.68	—	—	—	—	—	—
Erickson (MI)	318	12,588	.92	9.56	168.71	42.47	—	—	—	—	—	—
Los Angeles Dept of Wtr and Pwr	5,218	11,818	.52	8.94	137.22	32.43	132	11,836	.45	10.13	104.70	24.79
Intermountain (UT)	5,218	11,818	.52	8.94	137.22	32.43	132	11,836	.45	10.13	104.70	24.79
Louisville Gas and Electric	6,596	11,417	3.42	12.54	92.46	21.11	1,106	11,277	3.05	12.88	97.63	22.02
Cane Run (KY)	1,355	11,335	3.56	11.23	96.53	21.88	249	11,317	3.28	12.67	90.43	20.47
Mill Creek (KY)	3,753	11,301	3.18	12.42	93.53	21.14	704	11,424	2.91	12.38	95.68	21.86
Trimble County (KY)	1,488	11,783	3.89	14.02	86.33	20.34	153	10,540	3.32	15.54	119.94	25.28
Lower Colorado River Authority	3,114	8,531	.32	5.45	88.96	15.18	3,312	8,423	.34	11.25	92.41	15.57
S Seymour-Fayette (TX)	3,114	8,531	.32	5.45	88.96	15.18	3,312	8,423	.34	11.25	92.41	15.57
Madison Gas and Electric	—	—	—	—	—	—	199	11,019	1.51	9.10	152.70	33.65
Blount (WI)	—	—	—	—	—	—	199	11,019	1.51	9.10	152.70	33.65
Manitowoc Public Utilities	—	—	—	—	—	—	158	12,724	1.44	7.56	172.30	43.85
Manitowoc (WI)	—	—	—	—	—	—	158	12,724	1.44	7.56	172.30	43.85
Marquette Bd of Light and Power	169	9,319	.33	4.09	124.90	23.28	25	13,247	.83	7.67	206.14	54.62
Shiras (MI)	169	9,319	.33	4.09	124.90	23.28	25	13,247	.83	7.67	206.14	54.62
Michigan South Central Power	—	—	—	—	—	—	173	11,953	2.72	11.77	169.45	40.51
Project I (MI)	—	—	—	—	—	—	173	11,953	2.72	11.77	169.45	40.51
MidAmerican Energy	13,488	8,599	.33	5.12	74.77	12.86	119	9,095	.26	5.39	94.93	17.27
Riverside (IA)	433	8,641	.31	5.27	82.23	14.21	—	—	—	—	—	—
Council Bluffs (IA)	3,668	8,570	.31	5.26	60.36	10.35	—	—	—	—	—	—
George Neal 1-4 (IA)	6,627	8,661	.35	5.01	75.04	13.00	119	9,095	.26	5.39	94.93	17.27
Louisa (IA)	2,760	8,481	.30	5.19	92.28	15.65	—	—	—	—	—	—
Minnesota Power and Light	4,268	9,053	.56	6.65	117.73	21.31	—	—	—	—	—	—
Laskin Energy Center (MN)	431	9,368	.37	4.38	121.02	22.67	—	—	—	—	—	—
Boswell Energy Center (MN)	3,837	9,017	.58	6.91	117.34	21.16	—	—	—	—	—	—
Minnkota Power Coop	3,972	6,667	.87	8.28	71.41	9.52	—	—	—	—	—	—
Young (ND)	3,972	6,667	.87	8.28	71.41	9.52	—	—	—	—	—	—

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Mississippi Power	**3,465**	**11,768**	**0.69**	**7.85**	**155.29**	**36.55**	**1,631**	**11,258**	**0.54**	**9.19**	**189.12**	**42.58**
Watson (MS)	1,978	11,652	.80	7.11	153.88	35.86	235	11,442	.85	6.66	185.02	42.34
Daniel (MS)	1,487	11,923	.55	8.83	157.12	37.47	1,396	11,228	.49	9.62	189.82	42.63
Monongahela Power (APS)	**3,483**	**12,395**	**2.54**	**11.18**	**109.71**	**27.20**	**79**	**11,964**	**2.34**	**12.96**	**104.85**	**25.09**
Albright (WV)	380	12,561	1.62	11.61	106.15	26.67	40	12,011	1.55	13.56	102.33	24.58
Ft Martin (WV)	556	12,469	1.60	11.18	106.51	26.56	—	—	—	—	—	—
Harrison (WV)	1,119	12,269	3.35	12.48	120.64	29.60	7	12,476	3.50	10.81	88.11	21.99
Rivesville (WV)	246	11,758	1.04	12.79	119.35	28.07	10	11,660	.84	10.83	171.71	40.04
Willow Island (WV)	481	13,011	1.46	7.60	112.57	29.29	7	13,048	1.56	6.72	105.80	27.61
Pleasants (WV)	702	12,248	3.73	10.75	91.50	22.41	16	11,383	5.04	16.20	76.66	17.45
Montana-Dakota Utilities	**3,417**	**6,938**	**1.00**	**8.92**	**79.84**	**11.08**	—	—	—	—	—	—
Heskett (ND)	561	7,069	.76	7.25	96.00	13.57	—	—	—	—	—	—
Lewis and Clark (MT)	307	6,539	.53	9.51	94.93	12.42	—	—	—	—	—	—
Coyote (ND)	2,550	6,958	1.11	9.21	74.53	10.37	—	—	—	—	—	—
Muscatine Power and Water	**951**	**8,278**	**.61**	**6.30**	**87.73**	**14.53**	—	—	—	—	—	—
Muscatine (IA)	951	8,278	.61	6.30	87.73	14.53	—	—	—	—	—	—
Nebraska Public Power System	**5,707**	**8,576**	**.30**	**4.69**	**49.69**	**8.52**	**899**	**8,593**	**.32**	**4.55**	**65.15**	**11.20**
Sheldon (NE)	—	—	—	—	—	—	899	8,593	.32	4.55	65.15	11.20
Gerald Gentleman (NE)	5,707	8,576	.30	4.69	49.69	8.52	—	—	—	—	—	—
Nevada Power	**1,100**	**12,003**	**.73**	**8.71**	**121.01**	**29.05**	**1,053**	**11,680**	**.44**	**8.95**	**115.03**	**26.87**
Gardner (NV)	1,100	12,003	.73	8.71	121.01	29.05	1,053	11,680	.44	8.95	115.03	26.87
Northern Indiana Public Service	**7,648**	**10,073**	**1.30**	**6.64**	**124.89**	**25.16**	**1,486**	**9,767**	**1.20**	**6.75**	**134.94**	**26.36**
Bailly (IN)	1,151	11,331	2.58	8.55	142.00	32.18	252	11,172	2.83	8.50	145.79	32.57
Mitchell (IN)	949	9,149	.29	5.19	123.35	22.57	59	10,302	.31	7.29	170.48	35.13
Michigan City (IN)	1,171	9,480	.39	5.96	118.43	22.45	256	9,722	.34	6.64	138.67	26.96
Rollin Schahfer (IN)	4,377	10,102	1.43	6.64	121.76	24.60	919	9,361	1.04	6.27	127.80	23.93
Northern States Power	**13,142**	**8,809**	**.44**	**6.66**	**93.96**	**16.55**	**113**	**10,740**	**.34**	**5.56**	**157.15**	**33.76**
Black Dog (MN)	661	8,836	.20	4.39	100.77	17.81	—	—	—	—	—	—
High Bridge (MN)	781	8,958	.20	4.25	92.35	16.55	—	—	—	—	—	—
King (MN)	1,742	8,903	.37	5.68	102.59	18.27	—	—	—	—	—	—
Riverside (MN)	1,310	8,964	.20	4.20	94.16	16.88	—	—	—	—	—	—
Bay Front (WI)	53	8,881	.20	4.19	118.31	21.01	113	10,740	.34	5.56	157.15	33.76
Sherburne County (MN)	8,595	8,750	.53	7.64	91.62	16.03	—	—	—	—	—	—
Ohio Power	**9,483**	**12,080**	**2.17**	**10.92**	**156.64**	**37.84**	**6,115**	**11,616**	**2.71**	**12.04**	**121.02**	**28.12**
Muskingum (OH)	1,622	12,026	1.45	11.01	137.28	33.02	1,726	11,664	3.07	12.05	126.53	29.52
Kammer (WV)	1,488	13,002	1.46	7.58	112.03	29.13	35	13,289	1.26	6.72	116.48	30.96
Mitchell (WV)	2,452	12,089	.76	12.98	148.17	35.82	1,048	12,326	.91	12.93	144.18	35.54
Gavin (OH)	3,920	11,746	3.62	10.86	189.03	44.41	3,306	11,349	3.11	11.81	110.15	25.00
Ohio Valley Electric Corp	**930**	**13,235**	**1.13**	**7.28**	**120.06**	**31.78**	**1,624**	**11,952**	**2.74**	**8.99**	**98.06**	**23.44**
Kyger Creek (OH)	930	13,235	1.13	7.28	120.06	31.78	1,624	11,952	2.74	8.99	98.06	23.44
Oklahoma Gas and Electric	**8,609**	**8,768**	**.25**	**5.06**	**78.20**	**13.71**	—	—	—	—	—	—
Muskogee (OK)	5,166	8,768	.25	5.10	78.39	13.75	—	—	—	—	—	—
Sooner (OK)	3,443	8,769	.25	5.01	77.92	13.66	—	—	—	—	—	—
Omaha Public Power District	**2,543**	**8,657**	**.31**	**5.60**	**59.57**	**10.31**	**2,695**	**8,442**	**.32**	**5.48**	**56.18**	**9.49**
North Omaha (NE)	1,451	8,758	.30	5.70	62.02	10.86	813	8,439	.32	5.55	59.33	10.01
Nebraska City (NE)	1,093	8,524	.33	5.47	56.24	9.59	1,883	8,443	.32	5.45	54.83	9.26
Orlando Utilities Comm	**2,523**	**12,723**	**1.20**	**9.18**	**165.92**	**42.22**	**21**	**12,759**	**.99**	**8.90**	**186.40**	**47.57**
Stanton Energy (FL)	2,523	12,723	1.20	9.18	165.92	42.22	21	12,759	.99	8.90	186.40	47.57
Orrville, City of	**180**	**11,631**	**3.89**	**10.01**	**102.95**	**23.95**	—	—	—	—	—	—
Orrville (OH)	180	11,631	3.89	10.01	102.95	23.95	—	—	—	—	—	—
Otter Tail Power	**2,182**	**8,427**	**.33**	**5.49**	**103.27**	**17.41**	**511**	**9,247**	**.35**	**4.23**	**125.70**	**23.25**
Hoot Lake (MN)	—	—	—	—	—	—	511	9,247	.35	4.23	125.70	23.25
Big Stone (SD)	2,182	8,427	.33	5.49	103.27	17.41	—	—	—	—	—	—

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Owensboro Municipal Utilities	1,128	10,734	3.26	11.62	91.04	19.54	12	9,124	2.12	11.81	80.26	14.65
Smith (KY)	1,128	10,734	3.26	11.62	91.04	19.54	12	9,124	2.12	11.81	80.26	14.65
PacifiCorp	19,082	10,106	.58	8.60	91.57	18.51	3,134	8,455	.35	5.62	56.70	9.59
Carbon (UT)	547	12,181	.48	8.96	59.40	14.47	14	12,108	.33	6.80	50.40	12.20
Johnston (WY)	237	8,162	.44	5.73	67.84	11.07	3,002	8,380	.34	5.49	55.35	9.28
Naughton (WY)	2,266	9,883	.97	5.07	96.60	19.09	—	—	—	—	—	—
Wyodak (WY)	1,929	8,060	.60	7.04	74.02	11.93	—	—	—	—	—	—
Emery-Hunter (UT)	3,463	11,721	.54	9.28	90.62	21.24	36	11,513	.46	10.30	76.40	17.59
Jim Bridger (WY)	8,369	9,375	.53	9.75	105.01	19.69	82	9,229	.42	8.10	92.20	17.02
Huntington (UT)	2,271	12,004	.42	8.34	69.72	16.74	—	—	—	—	—	—
Painesville Electric Light Dept	88	12,376	2.50	7.48	137.72	34.09	—	—	—	—	—	—
Painesville (OH)	88	12,376	2.50	7.48	137.72	34.09	—	—	—	—	—	—
Philadelphia Electric	174	13,158	2.10	7.84	141.87	37.33	34	12,832	.94	9.47	225.90	57.97
Cromby (PA)	10	13,053	2.21	8.15	143.36	37.43	3	11,881	2.49	13.36	237.94	56.54
Eddystone (PA)	164	13,165	2.09	7.82	141.77	37.33	31	12,924	.80	9.10	224.82	58.11
Plains Elec Gen and Trans Coop	533	9,159	.83	18.41	135.12	24.75	—	—	—	—	—	—
Escalante (NM)	533	9,159	.83	18.41	135.12	24.75	—	—	—	—	—	—
Platte River Authority	1,312	8,832	.23	5.12	61.65	10.89	—	—	—	—	—	—
Rawhide (CO)	1,312	8,832	.23	5.12	61.65	10.89	—	—	—	—	—	—
Portland General Electric	—	—	—	—	—	—	2,583	8,706	.38	6.21	110.99	19.33
Boardman (OR)	—	—	—	—	—	—	2,583	8,706	.38	6.21	110.99	19.33
Public Serv Co of New Hampshire	892	13,144	1.69	6.88	163.66	43.02	818	12,871	.95	6.59	171.18	44.07
Merrimack (NH)	892	13,144	1.69	6.88	163.66	43.02	233	13,271	1.66	6.70	171.55	45.53
Schiller (NH)	—	—	—	—	—	—	585	12,712	.67	6.55	171.02	43.48
Public Serv Co of Oklahoma	3,047	8,765	.40	5.31	117.87	20.66	225	8,447	.31	5.10	88.26	14.91
Northeastern (OK)	3,047	8,765	.40	5.31	117.87	20.66	225	8,447	.31	5.10	88.26	14.91
Public Service Co of Colorado	7,741	9,353	.38	6.32	87.33	16.34	2,743	10,238	.40	7.66	93.93	19.23
Arapahoe (CO)	13	8,530	.29	4.40	82.60	14.09	844	8,766	.29	5.52	80.61	14.13
Cameo (CO)	296	11,081	.48	11.80	96.72	21.44	—	—	—	—	—	—
Cherokee (CO)	926	11,352	.49	9.78	96.52	21.91	1,130	11,325	.49	9.62	97.60	22.11
Comanche (CO)	2,303	8,605	.32	4.52	65.10	11.20	189	8,511	.33	5.49	57.35	9.76
Valmont (CO)	10	11,832	.52	8.02	111.30	26.34	580	10,825	.41	7.67	111.54	24.15
Hayden (CO)	1,666	10,386	.42	8.21	100.90	20.96	—	—	—	—	—	—
Pawnee (CO)	2,525	8,412	.36	4.80	90.91	15.30	—	—	—	—	—	—
Public Service Co of Indiana	15,449	10,993	1.66	9.15	109.35	24.04	1,093	11,686	1.56	7.14	122.83	28.71
Cayuga (IN)	3,176	10,926	.95	8.27	124.68	27.25	2	11,360	2.78	9.20	142.60	32.40
Edwardsport (IN)	183	11,113	1.40	8.40	113.48	25.22	168	11,160	1.56	8.65	103.10	23.01
Noblesville (IN)	185	10,508	1.55	8.72	145.36	30.55	—	—	—	—	—	—
Gallagher (IN)	820	12,217	1.97	7.44	122.30	29.88	438	11,858	1.79	7.88	138.21	32.78
Wabash River (IN)	2,121	10,729	1.49	9.15	107.67	23.10	—	—	—	—	—	—
Gibson Station (IN)	8,962	10,974	1.93	9.64	102.22	22.44	485	11,713	1.35	5.95	115.19	26.98
Public Service Co of New Mexico	6,118	9,542	.70	22.49	184.67	35.25	—	—	—	—	—	—
San Juan (NM)	6,118	9,542	.70	22.49	184.67	35.25	—	—	—	—	—	—
Richmond Power and Light	260	11,798	2.04	10.22	149.24	35.22	60	11,444	2.24	10.71	167.07	38.24
Whitewater (IN)	260	11,798	2.04	10.22	149.24	35.22	60	11,444	2.24	10.71	167.07	38.24
Rochester Dept Public Utilities	184	11,680	.97	7.42	181.47	42.39	7	11,000	.50	7.20	260.80	57.38
Silver Lake (MN)	184	11,680	.97	7.42	181.47	42.39	7	11,000	.50	7.20	260.80	57.38
Rochester Gas and Electric Corp	359	13,216	2.18	7.21	130.55	34.51	301	13,034	1.92	8.13	152.51	39.76
Russell Station 7 (NY)	359	13,216	2.18	7.21	130.55	34.51	301	13,034	1.92	8.13	152.51	39.76
Salt River Project	10,733	10,667	.51	10.49	119.21	25.43	956	9,383	.46	10.09	127.83	23.99
Navajo (AZ)	8,223	10,909	.53	9.35	117.14	25.56	—	—	—	—	—	—
Coronado (AZ)	2,510	9,875	.45	14.21	126.71	25.02	956	9,383	.46	10.09	127.83	23.99

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
San Miguel Electric	3,282	5,200	2.06	25.56	79.59	8.28	—	—	—	—	—	—
San Miquel (TX)	3,282	5,200	2.06	25.56	79.59	8.28	—	—	—	—	—	—
Savannah Electric and Power	—	—	—	—	—	—	723	12,507	0.73	65.82	152.20	38.07
Kraft (GA)	—	—	—	—	—	—	436	12,526	.74	7.45	142.18	35.62
McIntosh (GA)	—	—	—	—	—	—	287	12,477	.72	154.29	167.45	41.79
Seminole Electric Coop	2,175	12,108	2.83	8.37	168.06	40.70	1,126	12,385	2.72	8.72	203.24	50.34
Seminole (FL)	2,175	12,108	2.83	8.37	168.06	40.70	1,126	12,385	2.72	8.72	203.24	50.34
Sierra Pacific Power	422	11,175	.40	8.90	203.15	45.40	546	11,284	.40	8.17	122.46	27.64
North Valmy (NV)	422	11,175	.40	8.90	203.15	45.40	546	11,284	.40	8.17	122.46	27.64
Sikeston Brd of Mun Utilities	802	8,770	.34	5.49	108.55	19.04	—	—	—	—	—	—
Sikeston (MO)	802	8,770	.34	5.49	108.55	19.04	—	—	—	—	—	—
South Carolina Electric and Gas	5,913	12,525	1.03	8.92	152.80	38.28	782	12,755	1.26	8.44	177.81	45.36
Canadys (SC)	898	12,600	1.26	8.52	154.75	39.00	98	12,592	1.26	9.48	211.26	53.20
Mcmeekin (SC)	591	12,169	.97	10.48	155.37	37.82	39	12,387	1.48	10.13	209.77	51.97
Urguhart (SC)	483	13,050	1.38	7.26	147.45	38.49	156	13,084	1.33	7.27	172.93	45.25
Wateree (SC)	1,507	12,354	1.05	9.61	154.88	38.27	350	12,798	1.38	8.95	175.97	45.04
Williams (SC)	1,568	12,951	.81	7.54	152.36	39.46	—	—	—	—	—	—
Cope (SC)	865	11,924	.96	10.50	149.26	35.59	138	12,493	.79	7.27	155.37	38.82
South Carolina Public Serv Auth	4,228	12,803	1.25	8.56	142.83	36.57	3,648	12,461	1.27	10.31	169.47	42.24
Cross (SC)	2,086	12,880	1.35	7.99	139.43	35.92	1,196	12,482	1.27	10.78	180.20	44.98
Grainger (SC)	108	12,703	1.22	8.01	157.35	39.98	314	12,213	1.39	9.53	176.59	43.13
Jefferies (SC)	60	12,713	1.19	9.87	136.08	34.60	673	12,541	1.40	9.51	169.05	42.40
Winyah (SC)	1,974	12,729	1.15	9.15	145.89	37.14	1,466	12,461	1.18	10.46	159.42	39.73
South Mississippi Elec Pwr Assn	775	12,171	.97	11.82	150.03	36.52	252	12,612	.96	11.00	159.88	40.33
R D Morrow (MS)	775	12,171	.97	11.82	150.03	36.52	252	12,612	.96	11.00	159.88	40.33
Southern California Edison	4,933	10,963	.49	10.02	123.70	27.12	—	—	—	—	—	—
Mohave (NV)	4,933	10,963	.49	10.02	123.70	27.12	—	—	—	—	—	—
Southern Illinois Power Coop	519	9,894	2.45	15.79	77.19	15.27	441	10,491	3.59	17.48	105.15	22.06
Marion (IL)	519	9,894	2.45	15.79	77.19	15.27	441	10,491	3.59	17.48	105.15	22.06
Southern Indiana Gas and Elec	1,275	11,322	3.69	9.89	95.83	21.70	886	11,533	2.65	8.20	108.28	24.98
Culley (IN)	735	11,251	4.47	11.16	93.02	20.93	122	11,620	1.57	7.31	126.58	29.42
A B Brown (IN)	408	11,329	3.14	9.10	99.01	22.43	607	11,527	2.99	8.50	101.65	23.43
Warrick (IN)	132	11,690	1.08	5.33	101.32	23.69	157	11,489	2.16	7.73	119.64	27.49
Southwestern Electric Pwr	8,079	7,738	.81	8.51	160.09	24.77	3,804	8,599	.29	4.67	132.00	22.70
Flint Creek (AR)	1,139	8,468	.35	4.73	171.10	28.98	762	8,456	.36	4.94	115.73	19.57
Welsh Station (TX)	3,861	8,455	.35	4.76	159.71	27.01	2,991	8,637	.28	4.69	135.61	23.42
Pirkey (TX)	3,079	6,568	1.55	14.61	155.46	20.42	51	8,507	.10	.00	158.60	26.98
Southwestern Public Service	8,527	8,782	.27	5.48	137.97	24.23	36	8,692	.26	5.59	127.67	22.19
Harrington (TX)	4,531	8,841	.26	5.39	119.57	21.14	1	8,823	.26	5.65	115.86	20.44
Tolk (TX)	3,996	8,715	.27	5.57	159.14	27.74	35	8,687	.26	5.59	128.18	22.27
Springfield Wtr Lt and Pwr Dept	1,222	10,449	2.77	9.25	116.42	24.33	—	—	—	—	—	—
Dallman (IL)	1,065	10,476	3.05	9.41	113.84	23.85	—	—	—	—	—	—
Lakeside (IL)	157	10,268	.86	8.19	134.29	27.58	—	—	—	—	—	—
St Joseph Light and Power	—	—	—	—	—	—	423	9,719	.34	5.71	113.80	22.12
Lakeroad (MO)	—	—	—	—	—	—	423	9,719	.34	5.71	113.80	22.12
Sunflower Electric Power Corp	1,363	8,468	.31	5.28	104.90	17.76	—	—	—	—	—	—
Holcomb (KS)	1,363	8,468	.31	5.28	104.90	17.76	—	—	—	—	—	—
Tampa Electric[2]	3,472	11,850	2.36	8.39	164.98	39.10	3,857	11,315	2.07	8.21	147.09	33.29
Gannon (FL)	55	12,711	1.23	9.10	152.20	38.69	245	12,615	1.20	8.76	180.38	45.51
Davant Transfer (FL)	3,417	11,836	2.38	8.38	165.20	39.11	3,612	11,226	2.12	8.17	144.55	32.45
Tennessee Valley Authority[3]	32,077	11,465	1.66	10.31	117.49	26.94	4,478	11,574	2.01	12.24	153.32	35.49

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Tennessee Valley Authority[3]												
Colbert (AL)	745	11,915	1.65	12.21	112.50	26.81	330	11,852	0.80	14.62	190.16	45.07
Widows Creek (AL)	1,917	11,942	2.31	12.01	129.37	30.90	1,166	11,845	2.43	12.66	156.29	37.03
Paradise (KY)	4,154	10,527	3.85	18.48	95.13	20.03	626	10,258	3.93	20.05	104.23	21.38
Shawnee (KY)	3,333	11,447	.54	7.91	133.09	30.47	46	11,404	1.24	8.61	145.02	33.07
Bull Run (TN)	1,905	12,421	.97	10.04	130.78	32.49	200	12,414	.83	10.66	182.96	45.43
Cumberland (TN)	5,578	11,993	2.79	9.32	102.81	24.66	453	12,102	2.38	10.70	178.46	43.19
Gallatin (TN)	16	12,667	2.43	8.77	117.21	29.69	—	—	—	—	—	—
Sevier (TN)	1,690	12,720	.91	10.59	128.10	32.59	90	12,592	.82	10.98	225.79	56.86
Johnsonville (TN)	2	11,981	1.88	11.52	106.13	25.43	7	12,102	1.15	10.90	187.30	45.33
Kingston (TN)	3,107	12,238	1.06	11.80	130.03	31.83	301	12,691	.94	9.11	145.54	36.94
GRT Terminal (TN)	7,759	10,879	.87	7.50	118.52	25.79	1,192	11,191	1.44	9.14	145.43	32.55
Cora Transfer (TN)	1,872	10,372	.35	6.22	119.11	24.71	67	12,232	.51	9.28	120.46	29.47
Texas Municipal Power	**2,088**	**8,449**	**.31**	**5.47**	**134.41**	**22.71**	**1**	**8,777**	**.50**	**7.19**	**123.24**	**21.63**
Gibbons Creek (TX)	2,088	8,449	.31	5.47	134.41	22.71	1	8,777	.50	7.19	123.24	21.63
Texas New Mexico Power Co	**1,881**	**6,758**	**.93**	**16.44**	**150.68**	**20.37**	**—**	**—**	**—**	**—**	**—**	**—**
TNP One (TX)	1,881	6,758	.93	16.44	150.68	20.37	—	—	—	—	—	—
TXU Electric Co[4]	**27,297**	**6,837**	**.79**	**13.73**	**131.74**	**18.01**	**—**	**—**	**—**	**—**	**—**	**—**
Big Brown (TX)	5,383	7,323	.60	12.09	149.31	21.87	—	—	—	—	—	—
Martin Lake (TX)	11,604	6,796	1.10	12.63	113.34	15.41	—	—	—	—	—	—
Monticello (TX)	9,474	6,646	.50	15.77	144.69	19.23	—	—	—	—	—	—
Sandow No 4 (TX)	836	6,441	1.08	16.65	121.24	15.62	—	—	—	—	—	—
Tri-State G & T Assn Inc	**4,193**	**10,219**	**.43**	**7.19**	**115.53**	**23.61**	**728**	**10,204**	**.38**	**5.85**	**67.23**	**13.72**
Nucla (CO)	365	10,666	.97	20.30	112.80	24.06	—	—	—	—	—	—
Craig (CO)	3,827	10,176	.37	5.94	115.80	23.57	728	10,204	.38	5.85	67.23	13.72
Tucson Electric Power Co	**3,402**	**9,291**	**.85**	**17.51**	**138.22**	**25.69**	**267**	**11,287**	**.50**	**9.94**	**176.14**	**39.76**
Irvington (AZ)	72	10,082	.44	12.96	291.61	58.80	267	11,287	.50	9.94	176.14	39.76
Springerville (AZ)	3,331	9,274	.86	17.60	134.64	24.97	—	—	—	—	—	—
United Power Association	**937**	**6,685**	**.72**	**8.75**	**74.36**	**9.94**	**—**	**—**	**—**	**—**	**—**	**—**
Stanton (ND)	937	6,685	.72	8.75	74.36	9.94	—	—	—	—	—	—
UtiliCorp United Inc	**1,683**	**9,725**	**.33**	**5.90**	**93.30**	**18.15**	**—**	**—**	**—**	**—**	**—**	**—**
Sibley (MO)	1,683	9,725	.33	5.90	93.30	18.15	—	—	—	—	—	—
Vineland, City of	**27**	**13,051**	**.92**	**9.54**	**186.97**	**48.80**	**—**	**—**	**—**	**—**	**—**	**—**
H M Down (NJ)	27	13,051	.92	9.54	186.97	48.80	—	—	—	—	—	—
Virginia Electric and Power	**8,398**	**12,477**	**1.33**	**12.57**	**133.57**	**33.33**	**3,303**	**12,723**	**1.03**	**10.20**	**197.25**	**50.19**
Bremo Bluff (VA)	291	12,529	1.01	10.46	146.55	36.72	217	12,610	.94	10.99	208.92	52.69
Chesterfield (VA)	1,336	12,857	1.08	8.89	145.44	37.40	1,115	12,919	1.00	9.45	201.74	52.13
Chesapeake Energy (VA)	757	12,923	.80	8.97	159.21	41.15	511	12,890	.99	9.51	204.10	52.62
Possum Point (VA)	516	12,456	1.01	10.84	146.89	36.59	300	12,350	.91	11.00	187.27	46.25
Yorktown (VA)	565	13,051	1.52	7.96	150.24	39.22	117	12,790	1.33	10.50	204.33	52.27
Mount Storm (WV)	3,202	12,169	1.59	15.88	118.13	28.75	133	12,150	1.62	15.51	137.80	33.49
Clover (VA)	1,458	12,805	1.10	10.27	133.16	34.10	909	12,613	1.01	10.24	195.59	49.34
North Branch (VA)	273	10,033	2.75	29.02	96.82	19.43	—	—	—	—	—	—
West Penn Power (APS)	**542**	**12,821**	**2.20**	**9.29**	**107.01**	**27.44**	**—**	**—**	**—**	**—**	**—**	**—**
Hatfield (PA)	542	12,821	2.20	9.29	107.01	27.44	—	—	—	—	—	—
West Texas Utilities	**1,335**	**8,371**	**.36**	**5.38**	**150.53**	**25.20**	**749**	**8,587**	**.34**	**5.39**	**103.43**	**17.76**
Oklaunion (TX)	1,335	8,371	.36	5.38	150.53	25.20	749	8,587	.34	5.39	103.43	17.76
Western Farmers Electric Coop	**1,748**	**8,743**	**.28**	**4.82**	**108.00**	**18.88**	**—**	**—**	**—**	**—**	**—**	**—**
Hugo (OK)	1,748	8,743	.28	4.82	108.00	18.88	—	—	—	—	—	—
Wisconsin Electric Power	**11,585**	**9,300**	**.36**	**5.50**	**99.68**	**18.54**	**283**	**12,278**	**.92**	**9.26**	**203.28**	**49.92**
Presque Isle (MI)	1,845	10,237	.39	6.67	123.96	25.38	210	12,122	.84	9.11	192.03	46.56
Oak Creek (WI)	3,362	9,147	.28	4.48	100.14	18.32	—	—	—	—	—	—
Port Washington (WI)	427	13,157	1.47	7.27	124.64	32.80	73	12,731	1.15	9.68	234.21	59.63
Valley (WI)	578	12,044	.43	7.91	160.87	38.75	—	—	—	—	—	—
Pleasant Prairie (WI)	5,373	8,472	.31	5.35	76.86	13.02	—	—	—	—	—	—

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

Table 30. Receipts and Average Delivered Cost of Coal by Type of Purchase, Electric Utility, and Plant, 2001 (Continued)

Electric Utility Plant (State)	Contract						Spot					
	Receipts (1000 short tons)	Average Quality			Average Delivered Cost		Receipts (1000 short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	($ per short ton)
Wisconsin Power and Light	**1,352**	**8,954**	**0.31**	**5.17**	**121.85**	**21.82**	**6,129**	**8,711**	**0.33**	**5.28**	**101.14**	**17.62**
Edgewater (WI)	870	8,750	.31	5.82	119.78	20.96	1,592	9,141	.33	5.82	119.27	21.81
Nelson Dewey (WI)	482	9,323	.33	3.99	125.35	23.37	—	—	—	—	—	—
Columbia (WI)	—	—	—	—	—	—	4,537	8,560	.32	5.10	94.35	16.15
Wisconsin Public Service Corp	**3,308**	**8,849**	**.26**	**5.04**	**102.93**	**18.22**	**238**	**9,505**	**.27**	**4.96**	**131.23**	**24.95**
Pulliam (WI)	1,349	8,941	.22	4.41	103.85	18.57	227	9,437	.26	4.69	126.76	23.92
Weston (WI)	1,959	8,786	.29	5.47	102.27	17.97	11	10,903	.40	10.50	211.00	46.01
Wyandotte Dept of Mun Service	**127**	**12,512**	**.81**	**10.83**	**170.80**	**42.74**	**—**	**—**	**—**	**—**	**—**	**—**
Wyandotte (MI)	127	12,512	.81	10.83	170.80	42.74	—	—	—	—	—	—
Total	**607,801**	**9,877**	**.87**	**8.83**	**119.81**	**23.67**	**155,014**	**10,578**	**.96**	**8.81**	**135.39**	**28.64**

1 The cost reported under IMT Transfer (Louisiana) is the weighted average cost of coal delivered to this facility. Florida Power Corporation incurs additional costs for transporting coal from this transfer facility to the Crystal River power plant in Florida. This cost is not included in data shown in this report. When aggregated at the State level, data for this transfer facility are shown as though the coal were delivered to Florida.

2 The Tampa Electric Company reports coal destined for the Big Bend power plant in Florida as it is received at the Davant facility located in Louisiana. The cost reported under Davant Transfer is the weighted average cost of coal delivered to this facility. Tampa Electric incurs additional costs for transporting coal from Davant to the Big Bend plant. These costs are not included in data shown in this report. When aggregated at the State level, data for this transfer facility are shown as though the coal were delivered to Florida.

3 Coal reported as delivered to the Cora and GRT transfer facilities is later transferred to individual electric plants located in Alabama, Kentucky, and Tennessee. The cost of transportation from these facilities to the electric plants is not included in the costs shown in this report. Approximately 97 percent of the coal delivered to the Cora facility was transferred to the Allen plant in Tennessee. About 3 percent was transferred to plants in Alabama. Approximately 80 percent of the coal delivered to the GRT facility was transferred to plants in Tennessee. Approximately 19 percent was transferred to plants in Alabama. Less than 1 percent was transferred to plants in Kentucky.

4 Data for TXU Electric Company include some lignite delivered for the Aluminium Company of America (ALCOA) portion of Unit 4 of the Sandow Plant.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Alabama Electric Coop Inc	1,497	138.92	32.72	1.25	8	632.62	34.67	0.02	766	228.25	2.35	98	*	2
Lowman (AL)	1,497	138.92	32.72	1.25	8	632.62	34.67	.02	—	—	—	100	*	—
McWilliams (AL)	—	—	—	—	—	—	—	—	766	228.25	2.35	—	—	100
Alabama Power Co	24,211	141.68	30.07	.70	67	534.91	31.09	.03	12,186	522.91	5.38	98	*	2
Barry (AL)	3,928	173.46	41.21	.74	—	—	—	—	7,684	482.80	5.03	92	—	8
Gadsden (AL)	255	158.19	38.50	1.59	—	—	—	—	79	376.15	3.82	99	—	1
Gorgas 2 and 3 (AL)	2,675	197.59	48.10	.90	24	525.24	30.35	.02	—	—	—	100	*	—
Greene (AL)	1,350	126.49	30.30	1.51	7	561.80	32.80	.00	114	576.62	5.97	100	*	*
Gaston (AL)	5,219	139.37	33.94	1.23	36	535.74	31.23	.03	—	—	—	100	*	—
James Miller (AL)	10,784	110.46	19.44	.26	—	—	—	—	4,309	598.32	6.01	98	—	2
Alexandria, City of	—	—	—	—	—	—	—	—	128	342.00	3.53	—	—	100
Alexandria-Hunter (LA)	—	—	—	—	—	—	—	—	128	342.00	3.53	—	—	100
Ameren CIPS	6,614	119.45	22.81	.81	165	563.62	34.81	.29	3,169	353.30	3.63	97	1	2
Coffeen (IL)	2,015	126.99	26.11	1.14	9	636.18	36.79	.29	—	—	—	100	*	—
Grand Tower (IL)	—	—	—	—	—	—	—	—	3,169	353.30	3.63	—	—	100
Hutsonville (IL)	320	112.84	25.63	2.90	4	574.31	33.33	.29	—	—	—	100	*	—
Meredosia (IL)	674	138.38	29.31	1.81	123	550.88	34.75	.29	—	—	—	95	5	—
Newton (IL)	3,605	111.00	19.50	.25	29	598.60	34.62	.29	—	—	—	100	*	—
Ameren-UE	18,797	98.10	17.28	.45	47	592.73	34.11	.29	1,244	408.01	4.20	100	*	*
Venice No.2 (IL)	—	—	—	—	—	—	—	—	679	385.87	3.97	—	—	100
Labadie (MO)	9,284	96.81	16.90	.30	18	649.29	37.36	.29	—	—	—	100	*	—
Meramec (MO)	1,984	111.12	21.44	.90	—	—	—	—	565	434.62	4.47	99	—	1
Sioux (MO)	3,000	97.74	17.90	.50	4	624.30	35.92	.29	—	—	—	100	*	—
Rush Island (MO)	4,529	94.55	15.83	.53	25	546.96	31.47	.29	—	—	—	100	*	—
American Municipal Power Ohio	758	120.42	28.43	1.93	—	—	—	—	78	823.93	8.57	100	—	*
Gorsuch (OH)	758	120.42	28.43	1.93	—	—	—	—	78	823.93	8.57	100	—	*
Ames, City of	228	144.34	25.59	.20	9	618.81	35.68	.20	—	—	—	99	1	—
Ames (IA)	228	144.34	25.59	.20	9	618.81	35.68	.20	—	—	—	99	1	—
Anchorage, City of	—	—	—	—	—	—	—	—	6,876	206.12	2.06	—	—	100
George Sullivan (AK)	—	—	—	—	—	—	—	—	6,876	206.12	2.06	—	—	100
Appalachian Power	11,858	129.66	31.09	.72	231	665.55	38.81	.03	—	—	—	100	*	—
Clinch River (VA)	1,841	139.93	34.56	.69	10	637.48	37.36	.04	—	—	—	100	*	—
Glen Lyn (VA)	619	147.28	37.68	.86	24	608.51	35.47	.01	—	—	—	99	1	—
Amos (WV)	5,549	124.93	30.04	.77	127	687.67	40.20	.05	—	—	—	99	1	—
Kanawha River (WV)	1,138	105.57	25.55	.77	5	690.27	40.82	.03	—	—	—	100	*	—
Mountaineer (WV)	2,711	138.50	31.69	.58	65	645.41	37.40	.00	—	—	—	99	1	—
Arizona Electric Power Coop Inc	1,404	143.92	27.72	.70	—	—	—	—	5,318	506.72	5.23	83	—	17
Apache (AZ)	1,404	143.92	27.72	.70	—	—	—	—	5,318	506.72	5.23	83	—	17
Arizona Public Service	7,426	105.75	19.63	.64	185	999.75	57.99	.20	15,676	479.12	4.91	89	1	10
Cholla (AZ)	2,534	117.01	22.85	.49	—	—	—	—	4	489.99	5.00	100	—	*
Ocotillo (AZ)	—	—	—	—	—	—	—	—	4,480	487.52	5.00	—	—	100
Phoenix (AZ)	—	—	—	—	185	999.75	57.99	.20	5,549	511.90	5.25	—	16	84
Saguaro (AZ)	—	—	—	—	—	—	—	—	3,357	417.97	4.30	—	—	100
Yucca (AZ)	—	—	—	—	—	—	—	—	1,813	448.78	4.56	—	—	100
Four Corners (NM)	4,892	99.44	17.96	.72	—	—	—	—	473	566.88	5.73	99	—	1
Arkansas Power and Light	12,681	78.54	13.74	.27	75	624.72	37.05	.50	20,408	429.03	4.44	91	*	9
Lynch (AR)	—	—	—	—	*	625.04	36.97	.50	794	395.87	4.01	—	*	100
Moses (AR)	—	—	—	—	—	—	—	—	767	365.38	3.70	—	—	100
Couch (AR)	—	—	—	—	—	—	—	—	1,245	431.85	5.73	—	—	100
Lake Catherine (AR)	—	—	—	—	—	—	—	—	15,885	426.40	4.33	—	—	100
Ritchie (AR)	—	—	—	—	—	—	—	—	1,716	494.26	5.03	—	—	100
Whitebluff (AR)	6,109	89.04	15.14	.35	35	619.68	36.64	.50	—	—	—	100	*	—
Independence (AR)	6,573	69.30	12.43	.20	40	629.05	37.40	.50	—	—	—	100	*	—
Associated Electric Coop	9,554	89.37	15.93	.20	—	—	—	—	—	—	—	100	—	—
Madrid (MO)	4,428	100.22	17.86	.20	—	—	—	—	—	—	—	100	—	—
Hill (MO)	5,126	80.00	14.25	.20	—	—	—	—	—	—	—	100	—	—
Atlantic City Electric	187	233.21	59.98	1.66	—	—	—	—	—	—	—	100	—	—

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Atlantic City Electric														
England (NJ)	119	215.86	56.63	2.19	—	—	—	—	—	—	—	100	—	—
Deepwater (NJ)	68	265.14	65.80	.75	—	—	—	—	—	—	—	100	—	—
Basin Electric Power Coop	16,275	59.00	8.85	.50	56	664.64	38.49	0.34	—	—	—	100	*	—
Leland Olds (ND)	3,648	76.33	10.44	.69	16	681.40	39.46	.34	—	—	—	100	*	—
Laramie River (WY)	7,740	46.73	7.83	.31	23	656.98	38.05	.34	—	—	—	100	*	—
Antelope Valley (ND)	4,887	70.28	9.26	.66	17	659.43	38.19	.34	—	—	—	100	*	—
Big Rivers Electric Corp	265	90.30	21.42	3.23	—	—	—	—	—	—	—	100	—	—
Reid-Henderson (KY)	265	90.30	21.42	3.23	—	—	—	—	—	—	—	100	—	—
Black Hills Corporation	538	46.84	7.58	.62	1	660.97	39.66	.12	—	—	—	100	*	—
Neal Simpson II (WY)	538	46.84	7.58	.62	1	660.97	39.66	.12	—	—	—	100	*	—
Braintree, City of	—	—	—	—	79	580.83	33.69	.11	636	358.08	3.73	—	41	59
Potter Station (MA)	—	—	—	—	79	580.83	33.69	.11	636	358.08	3.73	—	41	59
Brazos Electric Power Coop	—	—	—	—	—	—	—	—	11,994	424.25	4.24	—	—	100
North Texas (TX)	—	—	—	—	—	—	—	—	62	350.10	3.50	—	—	100
Miller (TX)	—	—	—	—	—	—	—	—	11,932	424.64	4.25	—	—	100
Bryan Municipal Electric	—	—	—	—	—	—	—	—	3,156	384.17	3.92	—	—	100
Bryan (TX)	—	—	—	—	—	—	—	—	876	353.24	3.62	—	—	100
Dansby (TX)	—	—	—	—	—	—	—	—	2,280	396.12	4.03	—	—	100
Burbank Public Service Dept	—	—	—	—	—	—	—	—	1,683	966.60	9.90	—	—	100
Magnolia-Olive (CA)	—	—	—	—	—	—	—	—	1,683	966.60	9.90	—	—	100
Burlington Electric Light Dept	—	—	—	—	—	—	—	—	99	477.64	4.83	92	—	8
J C McNeil (VT)	—	—	—	—	—	—	—	—	99	477.64	4.83	92	—	8
Cardinal Operating Co (AEP)	4,303	141.74	33.94	1.32	38	703.15	41.13	.06	—	—	—	100	*	—
Cardinal (OH)	4,303	141.74	33.94	1.32	38	703.15	41.13	.06	—	—	—	100	*	—
Carolina Power and Light	9,383	164.54	40.83	.85	234	603.70	34.99	.20	—	—	—	99	1	—
Asheville (NC)	712	171.26	43.61	.92	90	634.14	36.75	.20	—	—	—	97	3	—
Cape Fear (NC)	487	154.45	38.45	.93	21	589.10	34.14	.20	—	—	—	99	1	—
Lee (NC)	702	157.85	39.29	.90	32	588.49	34.11	.20	—	—	—	99	1	—
Roxboro (NC)	4,923	163.01	40.32	.82	26	556.54	32.26	.20	—	—	—	100	*	—
Sutton (NC)	702	172.95	43.33	1.01	17	583.12	33.80	.20	—	—	—	99	1	—
Weatherspoon (NC)	277	177.25	45.11	1.10	23	615.29	35.66	.20	—	—	—	98	2	—
Robinson (SC)	262	171.76	43.55	1.19	4	621.12	36.00	.20	—	—	—	100	*	—
Mayo (NC)	1,317	165.12	40.18	.64	20	569.44	33.00	.20	—	—	—	100	*	—
Cedar Falls Utilities	38	194.72	48.03	1.41	—	—	—	—	44	373.85	3.74	95	—	5
Streeter (IA)	38	194.72	48.03	1.41	—	—	—	—	44	373.85	3.74	95	—	5
Central Elec Power Coop-Missouri	308	116.75	22.25	.77	—	—	—	—	—	—	—	100	—	—
Chamois (MO)	308	116.75	22.25	.77	—	—	—	—	—	—	—	100	—	—
Central Hudson Gas and Electric	37	156.10	41.55	.61	925	190.81	12.12	.99	23	746.50	7.72	14	85	*
Danskammer (NY)	37	156.10	41.55	.61	7	391.60	25.07	.43	17	767.29	7.96	94	4	2
Roseton (NY)	—	—	—	—	918	189.20	12.02	.99	6	684.83	7.01	—	100	*
Central Illinois Light	2,372	185.94	41.21	2.19	7	742.73	43.24	.20	—	—	—	100	*	—
Edwards (IL)	1,399	162.32	37.00	1.33	2	763.55	44.08	.35	—	—	—	100	*	—
Duck Creek (IL)	973	222.36	47.28	3.44	5	735.61	42.95	.15	—	—	—	100	*	—
Central Iowa Power Coop	180	116.87	26.28	2.94	6	630.34	36.98	.16	274	424.01	4.27	93	1	6
Summit Lake (IA)	—	—	—	—	6	630.34	36.98	.16	263	421.60	4.24	—	11	89
Fair Station (IA)	180	116.87	26.28	2.94	—	—	—	—	11	479.38	4.81	100	—	*
Central Louisiana Electric	5,602	139.94	20.94	.90	259	677.75	39.95	.32	25,815	442.74	4.64	75	1	24
Dolet Hills (LA)	3,754	141.66	19.38	1.15	—	—	—	—	51	591.26	6.10	100	—	*
Teche (LA)	—	—	—	—	125	661.70	39.50	.30	14,336	436.57	4.53	—	5	95
Rodemacher (LA)	1,848	137.21	24.12	.41	133	693.19	40.38	.33	11,429	449.67	4.77	72	2	27
Central Operating Co (AEP)	2,476	128.57	31.03	.94	44	688.72	39.57	.02	—	—	—	100	*	—
Sporn (WV)	2,476	128.57	31.03	.94	44	688.72	39.57	.02	—	—	—	100	*	—

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Central Power and Light	**1,695**	**138.82**	**27.50**	**0.33**	**791**	**667.25**	**39.88**	**0.10**	**81,499**	**409.83**	**4.21**	**27**	**4**	**69**
Joslin (TX)	—	—	—	—	52	663.37	39.01	.10	6,047	431.29	4.44	—	5	95
Bates (TX)	—	—	—	—	60	697.94	41.04	.10	4,986	407.73	4.17	—	7	93
Laredo (TX)	—	—	—	—	72	685.60	40.31	.10	5,809	396.57	4.08	—	7	93
Hill (TX)	—	—	—	—	31	732.78	43.93	.10	10,744	421.22	4.29	—	2	98
Nueces Bay (TX)	—	—	—	—	119	646.96	38.12	.10	15,939	428.73	4.43	—	4	96
La Palma (TX)	—	—	—	—	72	664.13	39.05	.10	6,422	410.47	4.17	—	6	94
Victoria (TX)	—	—	—	—	110	655.61	38.55	.09	7,123	397.74	4.07	—	8	92
Davis (TX)	—	—	—	—	273	663.45	40.76	.10	24,428	394.18	4.08	—	6	94
Coleto Creek (TX)	1,695	138.82	27.50	.33	*	248.50	14.61	.35	—	—	—	100	*	—
Chugach Electric Association	—	—	—	—	—	—	—	—	**10,773**	**255.22**	**2.55**	—	—	**100**
Beluga (AK)	—	—	—	—	—	—	—	—	10,773	255.22	2.55	—	—	100
Cincinnati Gas and Electric Co	**10,959**	**117.37**	**28.26**	**2.23**	**319**	**588.01**	**34.30**	**.27**	—	—	—	**99**	**1**	—
Beckjord (OH)	2,676	128.97	30.48	1.13	194	590.06	34.72	.26	—	—	—	98	2	—
Miami Fort (OH)	2,806	122.54	29.73	1.46	57	597.23	34.33	.22	—	—	—	100	*	—
East Bend (KY)	1,724	111.63	26.96	2.47	23	576.32	33.10	.21	—	—	—	100	*	—
Zimmer (OH)	3,753	108.05	26.16	3.49	45	573.22	33.08	.39	—	—	—	100	*	—
City of Austin Electric Dept	—	—	—	—	—	—	—	—	**24,132**	**453.35**	**4.65**	—	—	**100**
Decker Creek (TX)	—	—	—	—	—	—	—	—	17,556	466.07	4.77	—	—	100
Holly (TX)	—	—	—	—	—	—	—	—	6,576	419.89	4.35	—	—	100
City of Independence Pwr and Lt	**109**	**174.20**	**39.20**	**2.74**	**5**	**674.70**	**38.93**	**.50**	**60**	**378.74**	**3.84**	**96**	**1**	**2**
Blue Valley (MO)	109	174.20	39.20	2.74	5	674.70	38.93	.50	60	378.74	3.84	96	1	2
City of Lafayette Util System	—	—	—	—	—	—	—	—	**3,106**	**456.84**	**4.78**	—	—	**100**
Bonin (LA)	—	—	—	—	—	—	—	—	3,106	456.84	4.78	—	—	100
City Public Service-San Antonio	**5,938**	**101.01**	**17.07**	**.32**	—	—	—	—	**43,200**	**408.86**	**4.17**	**69**	—	**31**
Leon Creek (TX)	—	—	—	—	—	—	—	—	412	343.18	3.51	—	—	100
Mission Rd (TX)	—	—	—	—	—	—	—	—	224	344.38	3.52	—	—	100
Sommers (TX)	—	—	—	—	—	—	—	—	13,128	400.76	4.07	—	—	100
Braunig (TX)	—	—	—	—	—	—	—	—	10,582	392.04	4.00	—	—	100
Tuttle (TX)	—	—	—	—	—	—	—	—	1,489	340.89	3.47	—	—	100
JT Deely/Spruce (TX)	5,938	101.01	17.07	.32	—	—	—	—	20	452.45	4.58	100	—	*
Arthur Rosenberg (TX)	—	—	—	—	—	—	—	—	17,345	433.28	4.44	—	—	100
City Utilities of Springfield	**1,756**	**117.94**	**21.76**	**.29**	—	—	—	—	**1,366**	**514.51**	**5.18**	**96**	—	**4**
James River (MO)	939	123.88	23.55	.37	—	—	—	—	1,040	511.71	5.15	94	—	6
Southwest (MO)	817	110.65	19.70	.20	—	—	—	—	326	523.47	5.27	98	—	2
Coffeyville Muni Lt and Wtr Dept	—	—	—	—	—	—	—	—	**22**	**178.29**	**1.78**	—	—	**100**
Coffeyville (KS)	—	—	—	—	—	—	—	—	22	178.29	1.78	—	—	100
Colorado Springs Dept Pub Utils	**1,957**	**83.98**	**16.54**	**.37**	**4**	**634.43**	**36.46**	**.06**	**5,388**	**413.45**	**4.09**	**88**	*	**12**
Drake (CO)	987	89.40	18.81	.46	—	—	—	—	1,248	284.71	2.81	94	—	6
Birdsall (CO)	—	—	—	—	2	561.43	32.14	.05	2,602	417.31	4.12	35	*	65
Nixon (CO)	970	77.65	14.23	.27	2	685.80	39.52	.06	1,539	510.69	5.07	92	*	8
Columbia Water and Light	**30**	**206.58**	**55.40**	**1.10**	—	—	—	—	**19**	**737.94**	**7.38**	**98**	—	**2**
Columbia (MO)	30	206.58	55.40	1.10	—	—	—	—	19	737.94	7.38	98	—	2
Columbus Southern Power Co (AEP)	**4,045**	**129.52**	**30.24**	**2.40**	**22**	**595.53**	**35.08**	**.12**	—	—	—	**100**	*	—
Conesville (OH)	3,849	130.40	30.47	2.38	19	595.34	35.06	.13	—	—	—	100	*	—
Picway (OH)	196	111.97	25.83	2.71	3	596.84	35.21	.06	—	—	—	100	*	—
Consolidated Edison Co of NY	—	—	—	—	**1,157**	**397.95**	**25.00**	**.28**	**12,299**	**430.40**	**4.43**	—	**36**	**64**
East River (NY)	—	—	—	—	49	361.30	22.76	.29	6,270	381.37	3.93	—	5	95
Waterside (NY)	—	—	—	—	—	—	—	—	5,245	503.06	5.18	—	—	100
Storage Facility #7	—	—	—	—	1,108	399.58	25.10	.28	—	—	—	—	100	—
Storage Facility #5	—	—	—	—	—	—	—	—	785	335.64	3.43	—	—	100
Consumers Power	**9,017**	**134.01**	**26.92**	**.47**	**1,235**	**375.81**	**23.75**	**1.31**	**9,448**	**396.38**	**4.03**	**91**	**4**	**5**
Cobb (MI)	1,055	125.82	23.61	.54	61	667.53	27.55	.07	987	421.28	4.25	94	1	5
Karn-Weadock (MI)	1,222	108.19	19.06	.26	1,105	350.65	22.70	1.43	8,461	393.49	4.00	58	19	23
Campbell (MI)	4,030	140.22	29.05	.47	39	634.39	36.77	.50	—	—	—	100	*	—
Weadock (MI)	1,722	140.49	29.86	.57	24	647.01	37.50	.50	—	—	—	100	*	—
Whiting (MI)	988	132.09	26.40	.49	6	655.28	37.98	.50	—	—	—	100	*	—

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Cooperative Power Association	7,670	75.17	9.32	0.61	—	—	—	—	—	—	—	100	—	—
Coal Creek (ND)	7,670	75.17	9.32	.61	—	—	—	—	—	—	—	100	—	—
Dairyland Power Cooperative	2,526	122.16	24.07	.55	12	617.80	36.33	0.50	—	—	—	100	*	—
Alma-Madgett (WI)	1,691	109.70	20.29	.35	5	633.53	37.25	.50	—	—	—	100	*	—
Genoa No.3 (WI)	835	143.24	31.72	.97	7	606.00	35.63	.50	—	—	—	100	*	—
Dayton Power and Light Co	7,876	129.47	30.05	.83	96	590.52	35.24	.32	219	886.68	9.04	100	*	*
Hutchings (OH)	471	178.08	44.08	.81	—	—	—	—	219	886.68	9.04	98	—	2
Stuart (OH)	5,724	124.44	28.63	.88	75	616.06	35.62	.35	—	—	—	100	*	—
Killen (OH)	1,681	131.90	30.96	.65	20	508.70	33.85	.23	—	—	—	100	*	—
Delmarva Power and Light	24	216.91	54.54	.67	201	388.10	24.92	.81	—	—	—	32	68	—
Edgemoor (DE)	24	216.91	54.54	.67	201	388.10	24.92	.81	—	—	—	32	68	—
Denton, City of	—	—	—	—	1	220.00	12.91	.10	2,326	433.69	4.55	—	*	100
Spencer (TX)	—	—	—	—	1	220.00	12.91	.10	2,326	433.69	4.55	—	*	100
Deseret Generation & Trans	2,028	156.72	31.12	.40	7	514.50	29.82	.01	—	—	—	100	*	—
Bonanza (UT)	2,028	156.72	31.12	.40	7	514.50	29.82	.01	—	—	—	100	*	—
Detroit Edison Co	20,185	122.38	25.05	.59	970	493.35	29.68	.58	12,379	349.79	2.77	96	1	2
Conners Creek (MI)	—	—	—	—	1	669.18	38.79	.28	1,045	447.98	4.57	—	*	100
Harbor Beach (MI)	101	135.77	35.53	.97	7	637.93	36.92	.22	—	—	—	99	1	—
Marysville (MI)	32	141.06	36.91	.94	3	441.80	25.65	.23	128	378.18	3.77	85	2	13
Monroe (MI)	8,796	118.06	24.71	.64	34	631.07	36.76	.30	—	—	—	100	*	—
River Rouge (MI)	1,174	126.38	27.20	.55	1	588.68	34.10	.25	3,680	293.52	.81	96	*	4
St Clair (MI)	4,663	125.88	25.15	.64	236	631.79	36.99	.32	304	394.30	3.98	98	1	*
Trenton Channel (MI)	2,071	113.13	23.74	.70	14	640.75	37.11	.50	—	—	—	100	*	—
Belle River (MI)	3,348	133.67	25.43	.35	25	595.42	34.71	.13	—	—	—	100	*	—
Greenwood (MI)	—	—	—	—	649	429.88	26.22	.71	7,222	340.91	3.44	52	17	31
Detroit Public Lighting Comm	—	—	—	—	—	—	—	—	3,147	402.14	4.10	—	—	100
Mistersky (MI)	—	—	—	—	—	—	—	—	3,147	402.14	4.10	—	—	100
Dover, City of	—	—	—	—	271	374.78	23.97	.78	220	427.23	4.41	—	88	12
Mckee Run (DE)	—	—	—	—	271	374.78	23.97	.78	220	427.23	4.41	—	88	12
Duke Power	17,395	157.31	38.53	.87	131	534.57	31.20	.30	—	—	—	100	*	—
Allen (NC)	2,173	163.68	39.69	.89	25	530.35	31.01	.30	—	—	—	100	*	—
Buck (NC)	724	154.92	36.28	.70	—	—	—	—	—	—	—	100	—	—
Cliffside (NC)	1,684	157.85	39.47	.97	12	545.95	31.87	.30	—	—	—	100	*	—
Dan River (NC)	208	161.09	41.30	.65	—	—	—	—	—	—	—	100	—	—
Marshall (NC)	5,428	157.26	38.67	.86	32	546.14	31.88	.30	—	—	—	100	*	—
Riverbend (NC)	1,179	162.91	39.45	.97	—	—	—	—	—	—	—	100	—	—
Lee (SC)	572	180.34	43.77	.89	15	514.22	30.04	.30	—	—	—	99	1	—
Belews Creek (NC)	5,427	151.22	37.08	.86	46	532.65	31.05	.30	—	—	—	100	*	—
East Kentucky Power Coop	4,060	134.21	32.48	.94	14	568.14	33.07	.14	—	—	—	100	*	—
Cooper (KY)	931	131.34	32.38	1.34	3	606.91	35.33	.20	—	—	—	100	*	—
Dale (KY)	564	129.17	31.70	.80	4	594.83	34.63	.12	—	—	—	100	*	—
Spurlock (KY)	2,565	136.42	32.69	.83	7	535.59	31.18	.12	—	—	—	100	*	—
El Paso Electric	—	—	—	—	—	—	—	—	30,728	415.31	4.25	—	—	100
Rio Grande (TX)	—	—	—	—	—	—	—	—	8,471	364.74	3.73	—	—	100
Newman (TX)	—	—	—	—	—	—	—	—	22,257	434.56	4.44	—	—	100
Electric Energy	5,113	86.90	15.36	.23	2	694.86	39.69	.25	173	574.27	6.03	100	*	*
Joppa (IL)	5,113	86.90	15.36	.23	2	694.86	39.69	.25	173	574.27	6.03	100	*	*
Empire Dist Electric	541	114.96	21.83	.32	3	535.12	31.33	.04	155	512.39	5.17	98	*	1
Riverton (KS)	150	120.31	22.38	.53	—	—	—	—	155	512.39	5.17	95	—	5
Asbury (MO)	391	112.97	21.61	.25	3	535.12	31.33	.04	—	—	—	100	*	—
Fayetteville Public Works Comm	—	—	—	—	94	595.74	34.63	.27	746	435.01	4.50	—	41	59
Butler Warner (NC)	—	—	—	—	94	595.74	34.63	.27	746	435.01	4.50	—	41	59
Florida Power and Light	—	—	—	—	41,026	361.69	23.05	1.11	213,005	458.25	4.78	—	54	46
Cape Canaveral (FL)	—	—	—	—	4,028	378.43	24.07	.97	13,689	420.68	4.38	—	64	36
Cutler (FL)	—	—	—	—	—	—	—	—	3,059	455.61	4.76	—	—	100

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Florida Power and Light														
Fort Myers (FL)	—	—	—	—	2,461	348.53	22.36	1.76	17,506	411.88	4.28	—	46	54
Lauderdale (FL)	—	—	—	—	66	413.24	23.72	.08	47,245	490.62	5.13	—	1	99
Port Everglades (FL)	—	—	—	—	6,947	357.76	22.75	.95	10,090	403.08	4.20	—	81	19
Riviera (FL)	—	—	—	—	4,017	345.09	22.11	1.56	4,690	398.60	4.15	—	84	16
Sanford (FL)	—	—	—	—	4,191	376.31	23.97	1.48	5,873	487.41	5.10	—	81	19
Turkey Point (FL)	—	—	—	—	2,994	362.06	23.13	.98	12,843	445.68	4.65	—	59	41
Manatee (FL)	—	—	—	—	10,354	354.22	22.55	.96	—	—	—	—	100	—
Martin (FL)	—	—	—	—	5,968	373.70	23.79	.89	80,787	476.24	4.98	—	31	69
Putnam (FL)	—	—	—	—	—	—	—	—	17,222	409.75	4.27	—	—	100
Florida Power Corp[3]	5,439	200.10	49.94	0.81	10,739	335.68	21.64	1.45	9,231	322.98	3.34	63	32	4
Crystal River (FL)	3,037	198.12	50.19	.91	105	571.30	33.38	.49	—	—	—	99	1	—
Bartow (FL)	—	—	—	—	2,515	309.41	20.16	1.87	550	291.55	3.01	—	97	3
Suwannee (FL)	—	—	—	—	760	382.17	24.67	1.42	233	302.78	3.12	—	95	5
Hines Energy (FL)	—	—	—	—	22	358.25	19.95	.02	5,937	305.17	3.16	—	2	98
Anclote (FL)	—	—	—	—	6	521.56	30.27	.47	2,510	373.73	3.88	—	1	99
IMT Transfer (LA)	2,402	202.69	49.63	.68	—	—	—	—	—	—	—	100	—	—
Storage Facility # 1	—	—	—	—	7,332	336.71	21.66	1.32	—	—	—	—	100	—
Fort Pierce, City of	—	—	—	—	—	—	—	—	705	709.69	7.44	—	—	100
H D King (FL)	—	—	—	—	—	—	—	—	705	709.69	7.44	—	—	100
Fremont Dept of Public Utilities	323	98.20	17.56	.23	—	—	—	—	102	564.22	5.64	98	—	2
Wright (NE)	323	98.20	17.56	.23	—	—	—	—	102	564.22	5.64	98	—	2
Gainesville Regional Utilities	462	194.44	50.76	.70	102	489.05	30.73	1.35	2,897	478.20	5.00	77	4	19
Deerhaven (FL)	462	194.44	50.76	.70	78	480.26	30.33	1.41	2,063	484.61	5.07	82	3	15
Jr Kelly (FL)	—	—	—	—	24	518.26	32.04	1.16	834	462.27	4.82	—	15	85
Garland Municipal Pwr and Lt	—	—	—	—	—	—	—	—	4,170	424.43	4.31	—	—	100
Newman (TX)	—	—	—	—	—	—	—	—	102	368.94	3.77	—	—	100
Olinger (TX)	—	—	—	—	—	—	—	—	4,068	425.82	4.32	—	—	100
Georgia Power	33,639	166.38	39.06	.81	322	668.53	38.89	.50	177	305.92	3.15	100	*	*
Arkwright (GA)	184	157.77	40.30	2.11	*	696.30	40.50	.50	172	304.63	3.13	96	*	4
Atkinson-Mcdonough (GA)	1,266	142.87	36.46	1.08	—	—	—	—	2	331.43	3.39	100	—	*
Bowen (GA)	8,608	156.50	38.38	.98	21	569.63	33.14	.50	—	—	—	100	*	—
Hammond (GA)	1,910	147.28	37.58	.81	13	531.38	30.91	.50	—	—	—	100	*	—
Harllee Branch (GA)	3,516	179.95	44.95	1.05	10	593.76	34.54	.50	—	—	—	100	*	—
Mcmanus (GA)	—	—	—	—	172	733.23	42.65	.50	—	—	—	—	100	—
Mitchell (GA)	203	189.19	48.19	1.03	32	680.85	39.60	.50	—	—	—	96	4	—
Yates (GA)	2,736	163.21	41.16	1.10	18	587.18	34.16	.50	2	376.38	3.90	100	*	*
Wansley (GA)	4,677	162.66	40.41	.90	17	542.54	31.56	.50	—	—	—	100	*	—
Scherer (GA)	10,540	181.11	36.89	.42	38	580.59	33.77	.50	—	—	—	100	*	—
Glendale Public Service Dept	—	—	—	—	—	—	—	—	4,203	653.61	6.22	—	—	100
Glendale (CA)	—	—	—	—	—	—	—	—	4,203	653.61	6.22	—	—	100
Grand Haven Light & Power	205	133.29	34.02	2.35	—	—	—	—	14	699.28	6.99	100	—	*
J B Simms (MI)	205	133.29	34.02	2.35	—	—	—	—	14	699.28	6.99	100	—	*
Grand Island Utilities	449	72.20	12.68	.29	—	—	—	—	393	360.86	3.61	95	—	5
Platte (NE)	449	72.20	12.68	.29	—	—	—	—	—	—	—	100	—	—
Burdick (NE)	—	—	—	—	—	—	—	—	393	360.86	3.61	—	—	100
Grand River Dam Authority	3,489	88.60	14.96	.34	—	—	—	—	115	417.51	4.17	100	—	*
GRDA No 1 (OK)	3,489	88.60	14.96	.34	—	—	—	—	115	417.51	4.17	100	—	*
Greenville Electric Dept	—	—	—	—	—	—	—	—	147	416.35	4.42	—	—	100
Power Lane (TX)	—	—	—	—	—	—	—	—	147	416.35	4.42	—	—	100
Gulf Power	3,313	161.19	39.20	1.02	13	517.69	30.11	.45	1,064	289.62	2.90	99	*	1
Crist (FL)	2,110	157.39	38.00	1.11	5	406.04	23.62	.45	1,064	289.62	2.90	98	*	2
Scholtz (FL)	160	159.64	40.58	.93	1	593.62	34.53	.45	—	—	—	100	*	—
Smith (FL)	1,043	169.00	41.42	.83	7	579.44	33.71	.45	—	—	—	100	*	—
Gulf States Utilities	2,511	113.69	19.97	.38	—	—	—	—	174,783	416.57	4.34	20	—	80
Louisiana 1 (LA)	—	—	—	—	—	—	—	—	404	380.80	3.94	—	—	100
Nelson (LA)	2,511	113.69	19.97	.38	—	—	—	—	24,119	429.35	4.46	64	—	36

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Gulf States Utilities														
Willow Glen (LA)	—	—	—	—	—	—	—	—	40,568	423.42	4.42	—	—	100
Lewis Creek (TX)	—	—	—	—	—	—	—	—	26,621	404.53	4.21	—	—	100
Sabine (TX)	—	—	—	—	—	—	—	—	81,814	414.35	4.32	—	—	100
Spindletop Storage (TX)	—	—	—	—	—	—	—	—	1,257	360.99	3.74	—	—	100
Hamilton, City of	150	147.52	35.88	0.98	—	—	—	—	114	595.88	6.13	97	—	3
Hamilton (OH)	150	147.52	35.88	.98	—	—	—	—	114	595.88	6.13	97	—	3
Hastings Utilities	332	67.30	11.80	.29	—	—	—	—	—	—	—	100	—	—
Hastings (NE)	332	67.30	11.80	.29	—	—	—	—	—	—	—	100	—	—
Hawaiian Electric	—	—	—	—	10,262	490.34	30.80	0.46	—	—	—	—	100	—
Kahe (HI)	—	—	—	—	774	491.67	30.96	.45	—	—	—	—	100	—
Waiau (HI)	—	—	—	—	30	668.85	38.84	.25	—	—	—	—	100	—
Storage Facility # 1	—	—	—	—	9,458	489.71	30.76	.46	—	—	—	—	100	—
Holland Board of Public Wks	146	169.53	42.57	.86	1	626.00	36.02	.04	337	364.57	3.76	91	*	9
James De Young (MI)	146	169.53	42.57	.86	1	626.00	36.02	.04	337	364.57	3.76	91	*	9
Hoosier Energy R E C	3,736	102.93	22.96	2.82	23	605.43	35.09	.10	—	—	—	100	*	—
Frank E Ratts (IN)	709	104.62	23.42	1.36	3	555.73	32.21	.10	—	—	—	100	*	—
Merom (IN)	3,027	102.53	22.86	3.16	20	611.73	35.46	.10	—	—	—	100	*	—
Houston Lighting and Power	16,423	157.06	24.47	.74	—	—	—	—	181,033	423.17	4.32	58	—	42
Limestone (TX)	7,169	127.07	17.17	1.20	—	—	—	—	788	408.56	4.19	99	—	1
Cedar Bayou (TX)	—	—	—	—	—	—	—	—	53,981	419.65	4.28	—	—	100
Deepwater (TX)	—	—	—	—	—	—	—	—	1,081	403.94	4.20	—	—	100
Green Bayou (TX)	—	—	—	—	—	—	—	—	6,337	483.26	4.95	—	—	100
Robinson (TX)	—	—	—	—	—	—	—	—	55,307	401.76	4.09	—	—	100
Bertron (TX)	—	—	—	—	—	—	—	—	12,463	398.59	4.07	—	—	100
Wharton (TX)	—	—	—	—	—	—	—	—	19,529	479.39	4.86	—	—	100
Parish (TX)	9,254	175.32	30.13	.38	—	—	—	—	22,905	416.92	4.32	87	—	13
Webster (TX)	—	—	—	—	—	—	—	—	4,904	370.42	3.77	—	—	100
Storage Facility # 2	—	—	—	—	—	—	—	—	3,739	598.22	5.98	—	—	100
Imperial Irrigation District	—	—	—	—	76	631.66	36.61	.22	3,792	1,011.70	10.26	—	10	90
El Centro (CA)	—	—	—	—	76	631.66	36.61	.22	3,792	1,011.70	10.26	—	10	90
Indiana Michigan Power	11,904	117.41	22.71	.53	62	442.15	25.29	.08	—	—	—	100	*	—
Tanners Creek (IN)	2,455	115.86	27.23	1.35	24	591.81	34.52	.04	—	—	—	100	*	—
Rockport (IN)	9,449	117.92	21.53	.32	38	342.64	19.35	.10	—	—	—	100	*	—
Indiana-Kentucky Electric Corp	3,862	123.17	25.11	.57	7	602.79	34.43	.30	—	—	—	100	*	—
Clifty Creek (IN)	3,862	123.17	25.11	.57	7	602.79	34.43	.30	—	—	—	100	*	—
Indianapolis Power and Light	4,180	97.49	21.69	2.00	43	586.31	34.05	.04	—	—	—	100	*	—
Stout (IN)	1,232	111.48	24.28	1.17	36	571.97	33.24	.04	—	—	—	99	1	—
Pritchard (IN)	791	109.53	24.74	1.21	7	659.87	38.18	.04	—	—	—	100	*	—
Petersburg (IN)	2,157	85.27	19.10	2.77	—	—	—	—	—	—	—	100	—	—
Interstate Power	1,685	86.56	15.72	.34	23	595.77	35.03	.05	516	485.27	4.85	98	*	2
Dubuque (IA)	204	144.98	33.90	.57	2	535.71	31.50	.00	29	531.86	5.32	99	*	1
Lansing (IA)	812	81.62	14.21	.31	13	598.06	35.17	.03	—	—	—	99	1	—
Kapp (IA)	669	68.76	12.01	.30	—	—	—	—	55	540.02	5.40	100	—	*
Fox Lake (MN)	—	—	—	—	8	603.99	35.51	.08	432	475.16	4.75	—	10	90
IES Utilities	5,282	89.46	15.41	.34	108	627.83	36.92	.03	1,799	456.26	4.56	97	1	2
6th St (IA)	238	133.07	29.86	.36	1	645.32	37.94	.00	983	406.45	4.06	84	*	16
Praire Creek (IA)	763	86.08	14.72	.31	5	711.38	41.83	.00	66	426.14	4.26	99	*	1
Sutherland (IA)	570	81.13	14.77	.35	52	635.60	37.37	.04	683	520.80	5.21	91	3	6
Burlington (IA)	757	85.13	14.17	.36	39	611.65	35.97	.01	66	560.28	5.60	98	2	1
Ottumwa (IA)	2,954	88.49	14.86	.33	10	605.81	35.62	.06	—	—	—	100	*	—
Jacksonville Electric Authority	3,474	160.42	39.13	.99	4,099	337.25	21.48	1.45	8,403	460.98	4.88	74	19	7
St Johns River (FL)	3,436	159.65	38.95	.97	51	564.68	32.97	.35	—	—	—	100	*	—
Northside (FL)	38	231.10	55.99	2.37	3,340	324.11	20.63	1.59	7,199	464.02	4.91	7	69	25
Southside (FL)	—	—	—	—	708	383.67	24.64	.86	1,204	442.84	4.69	—	78	22
Jamestown Bd of Public Utilities	76	144.20	36.26	1.82	—	—	—	—	—	—	—	100	—	—
Samuel A Carlson (NY)	76	144.20	36.26	1.82	—	—	—	—	—	—	—	100	—	—

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Kansas City Bd Public Utilities	**1,572**	**80.43**	**13.34**	**0.36**	**33**	**566.67**	**32.84**	**0.51**	**846**	**428.93**	**4.33**	**96**	**1**	**3**
Kaw (KS)	—	—	—	—	*	687.70	39.86	.50	393	369.77	3.74	—	*	100
Quindaro (KS)	503	97.18	17.12	.29	27	563.17	32.64	.51	453	480.29	4.84	94	2	5
Nearman (KS)	1,069	71.80	11.55	.39	6	578.85	33.55	.50	—	—	—	100	*	—
Kansas City Power and Light	**9,445**	**80.49**	**14.18**	**.48**	**134**	**612.16**	**35.48**	**.07**	**2,205**	**487.42**	**4.87**	**98**	*	**1**
La Cygne (KS)	4,259	77.83	13.81	.67	55	616.43	35.70	.06	—	—	—	100	*	—
Hawthorne (MO)	841	109.65	19.11	.30	—	—	—	—	2,205	487.42	4.87	87	—	13
Montrose (MO)	1,851	87.38	15.35	.38	23	542.62	31.61	.05	—	—	—	100	*	—
Iatan (MO)	2,494	70.20	12.29	.30	15	588.81	34.12	.04	—	—	—	100	*	—
Storage Facility # 1	—	—	—	—	41	654.27	37.85	.10	—	—	—	—	100	—
Kansas Gas and Electric	—	—	—	—	**1,180**	**316.99**	**20.95**	**1.70**	**7,833**	**337.42**	**3.43**	—	**49**	**51**
Evans (KS)	—	—	—	—	483	344.59	22.78	1.70	5,055	339.22	3.47	—	38	62
Gill (KS)	—	—	—	—	585	291.06	19.23	1.70	2,128	333.84	3.42	—	64	36
Neosho (KS)	—	—	—	—	111	333.36	22.05	1.70	651	334.91	3.20	—	54	46
Kansas Power and Light Co	**13,942**	**115.59**	**20.09**	**.37**	**278**	**344.60**	**22.81**	**1.63**	**1,362**	**353.05**	**3.62**	**99**	**1**	**1**
Hutchinson (KS)	—	—	—	—	267	334.97	22.35	1.70	1,142	341.32	3.51	—	60	40
Lawrence (KS)	1,934	136.41	26.93	.37	—	—	—	—	105	464.33	4.74	100	—	*
Tecumseh (KS)	830	129.90	25.26	.36	—	—	—	—	116	368.95	3.74	99	—	1
Jeffrey Energy Cnt (KS)	11,178	110.13	18.52	.37	11	634.80	34.13	.05	—	—	—	100	*	—
Kentucky Power (AEP)	**3,236**	**102.76**	**24.64**	**.92**	**19**	**633.78**	**37.18**	**.04**	—	—	—	**100**	*	—
Big Sandy (KY)	3,236	102.76	24.64	.92	19	633.78	37.18	.04	—	—	—	100	*	—
Kentucky Utilities	**7,558**	**118.66**	**27.36**	**1.42**	**42**	**560.90**	**32.98**	**.40**	—	—	—	**100**	*	—
Brown (KY)	1,558	127.42	30.64	1.55	8	528.56	31.08	.40	—	—	—	100	*	—
Ghent (KY)	5,413	115.58	26.22	1.35	22	576.39	33.89	.40	—	—	—	100	*	—
Green River (KY)	454	122.48	28.33	2.04	7	510.83	30.04	.40	—	—	—	100	*	—
Tyrone (KY)	133	121.50	31.68	.80	5	612.10	35.99	.40	—	—	—	99	1	—
Lake Worth Utilities	—	—	—	—	**32**	**635.33**	**37.85**	**.70**	**2,757**	**621.71**	**6.38**	—	**6**	**94**
Tom G Smith (FL)	—	—	—	—	32	635.33	37.85	.70	2,757	621.71	6.38	—	6	94
Lakeland Dept of Elec Wtr Utils	**330**	**186.57**	**46.62**	**1.10**	**203**	**437.49**	**27.38**	**1.74**	**3,839**	**430.61**	**4.50**	**62**	**9**	**29**
Larsen Mem (FL)	—	—	—	—	12	418.59	26.47	2.37	1,030	421.89	4.40	—	7	93
Plant 3-Mcintosh (FL)	330	186.57	46.62	1.10	191	438.69	27.44	1.71	2,809	433.79	4.53	68	9	23
Lansing Board of Water and Light	**1,364**	**134.67**	**26.52**	**.47**	**13**	**382.80**	**22.19**	**.30**	—	—	—	**100**	*	—
Eckert (MI)	1,046	120.24	21.68	.34	10	394.60	22.87	.30	—	—	—	100	*	—
Erickson (MI)	318	168.71	42.47	.92	3	341.00	19.76	.30	—	—	—	100	*	—
Long Island Lighting	—	—	—	—	**10,346**	**341.99**	**21.92**	**.78**	**62,146**	**379.11**	**3.85**	—	**51**	**49**
Barrett (NY)	—	—	—	—	738	434.23	27.51	.34	14,151	375.60	3.89	—	24	76
Far Rockaway (NY)	—	—	—	—	—	—	—	—	3,265	562.46	5.86	—	—	100
Glenwood (NY)	—	—	—	—	—	—	—	—	9,246	531.86	5.46	—	—	100
Northport (NY)	—	—	—	—	8,165	332.14	21.32	.80	25,555	328.96	3.30	—	67	33
Port Jefferson (NY)	—	—	—	—	1,443	351.19	22.46	.90	9,929	305.46	3.07	—	48	52
Los Angeles Dept of Wtr and Pwr	**5,350**	**136.41**	**32.24**	**.51**	—	—	—	—	**41,175**	**1,166.95**	**11.88**	**75**	—	**25**
Harbor (CA)	—	—	—	—	—	—	—	—	4,096	1,133.19	11.53	—	—	100
Haynes (CA)	—	—	—	—	—	—	—	—	25,684	1,203.70	12.20	—	—	100
Scattergood (CA)	—	—	—	—	—	—	—	—	9,802	1,055.06	10.85	—	—	100
Valley (CA)	—	—	—	—	—	—	—	—	1,594	1,358.60	13.88	—	—	100
Intermountain (UT)	5,350	136.41	32.24	.51	—	—	—	—	—	—	—	100	—	—
Louisiana Power and Light	—	—	—	—	**1,454**	**524.03**	**33.29**	**.46**	**100,794**	**398.03**	**4.13**	—	**8**	**92**
Little Gypsy (LA)	—	—	—	—	234	556.50	33.79	.24	30,537	444.41	4.63	—	4	96
Nine Mile (LA)	—	—	—	—	194	555.88	33.81	.50	48,250	367.69	3.80	—	2	98
Sterlington (LA)	—	—	—	—	13	624.24	36.83	.50	11,609	410.45	4.23	—	1	99
Monroe (LA)	—	—	—	—	—	—	—	—	624	407.58	4.20	—	—	100
Waterford (LA)	—	—	—	—	1,014	510.14	33.03	.50	9,774	386.84	4.12	—	39	61
Louisville Gas and Electric	**7,702**	**93.20**	**21.24**	**3.37**	**30**	**545.95**	**32.10**	**.25**	**353**	**458.91**	**4.70**	**100**	*	*
Cane Run (KY)	1,604	95.58	21.66	3.51	—	—	—	—	122	533.44	5.47	100	—	*
Mill Creek (KY)	4,457	93.87	21.25	3.14	23	563.23	33.12	.25	231	419.37	4.30	100	*	*
Trimble County (KY)	1,641	89.16	20.80	3.83	7	487.35	28.66	.25	—	—	—	100	*	—
Lower Colorado River Authority	**6,426**	**90.73**	**15.38**	**.33**	—	—	—	—	**24,927**	**421.43**	**4.33**	**81**	—	**19**

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Lower Colorado River Authority														
Gideon (TX)	—	—	—	—	—	—	—	—	15,042	436.41	4.48	—	—	100
T C Ferguson (TX)	—	—	—	—	—	—	—	—	9,884	398.56	4.08	—	—	100
S Seymour-Fayette (TX)	6,426	90.73	15.38	0.33	—	—	—	—	—	—	—	100	—	—
Lubbock Power and Light Dept	—	—	—	—	—	—	—	—	5,572	459.38	4.62	—	—	100
Holly Ave (TX)	—	—	—	—	—	—	—	—	3,632	468.56	4.72	—	—	100
Plant 2 (TX)	—	—	—	—	—	—	—	—	1,940	442.06	4.42	—	—	100
Madison Gas and Electric	199	152.70	33.65	1.51	—	—	—	—	1,070	449.14	4.50	80	—	20
Blount (WI)	199	152.70	33.65	1.51	—	—	—	—	1,070	449.14	4.50	80	—	20
Manitowoc Public Utilities	158	172.30	43.85	1.44	—	—	—	—	—	—	—	100	—	—
Manitowoc (WI)	158	172.30	43.85	1.44	—	—	—	—	—	—	—	100	—	—
Marquette Bd of Light and Power	193	138.80	27.25	.40	13	642.67	37.25	0.02	—	—	—	98	2	—
Shiras (MI)	193	138.80	27.25	.40	13	642.67	37.25	.02	—	—	—	98	2	—
Massachusetts Mun Whsle Elec Co	—	—	—	—	—	—	—	—	2,830	325.64	3.34	—	—	100
Stonybrook (MA)	—	—	—	—	—	—	—	—	2,830	325.64	3.34	—	—	100
Medina Electric Coop	—	—	—	—	7	396.00	25.21	.48	554	365.05	4.25	—	7	93
Pearsall (TX)	—	—	—	—	7	396.00	25.21	.48	554	365.05	4.25	—	7	93
Michigan South Central Power	173	169.45	40.51	2.72	—	—	—	—	—	—	—	100	—	—
Project I (MI)	173	169.45	40.51	2.72	—	—	—	—	—	—	—	100	—	—
MidAmerican Energy	13,607	74.96	12.90	.33	15	559.40	31.95	.02	602	532.49	5.37	100	*	*
Riverside (IA)	433	82.23	14.21	.31	—	—	—	—	319	501.66	5.06	96	—	4
Council Bluffs (IA)	3,668	60.36	10.35	.31	9	525.62	30.02	.01	38	547.11	5.47	100	*	*
George Neal 1-4 (IA)	6,746	75.41	13.07	.35	6	610.63	34.88	.02	164	615.52	6.21	100	*	*
Louisa (IA)	2,760	92.28	15.65	.30	—	—	—	—	82	479.73	4.87	100	—	*
Minnesota Power and Light	4,268	117.73	21.31	.56	19	685.21	39.43	.20	—	—	—	100	*	—
Laskin Energy Center (MN)	431	121.02	22.67	.37	2	694.19	39.94	.20	—	—	—	100	*	—
Boswell Energy Center (MN)	3,837	117.34	21.16	.58	17	683.99	39.36	.20	—	—	—	100	*	—
Minnkota Power Coop	3,972	71.41	9.52	.87	19	583.97	34.34	.40	—	—	—	100	*	—
Young (ND)	3,972	71.41	9.52	.87	19	583.97	34.34	.40	—	—	—	100	*	—
Mississippi Power	5,096	165.79	38.48	.64	87	558.46	32.56	.33	39,722	351.07	3.61	74	*	26
Eaton (MS)	—	—	—	—	—	—	—	—	102	466.45	4.82	—	—	100
Sweatt (MS)	—	—	—	—	—	—	—	—	167	471.83	4.88	—	—	100
Watson (MS)	2,213	157.13	36.55	.80	10	674.03	38.77	.37	3,231	366.48	3.79	94	*	6
Daniel (MS)	2,883	172.46	39.96	.52	77	543.03	31.71	.33	33,499	338.46	3.48	66	*	34
Petal Gas (MS)	—	—	—	—	—	—	—	—	2,722	475.17	4.91	—	—	100
Mississippi Pwr and Lt	—	—	—	—	8,369	375.49	24.45	2.99	27,502	314.74	3.23	—	66	34
Wilson (MS)	—	—	—	—	4,772	381.14	24.73	3.00	16,149	305.34	3.12	—	65	35
Delta (MS)	—	—	—	—	505	389.45	25.67	3.00	1,135	426.18	4.36	—	74	26
Brown (MS)	—	—	—	—	1	615.44	36.40	.50	6,225	404.65	4.15	—	*	100
Gerald Andrus (MS)	—	—	—	—	3,091	364.48	23.81	2.99	3,993	182.62	1.90	—	83	17
Monongahela Power (APS)	3,561	109.61	27.15	2.53	14	650.05	38.50	.29	179	646.48	6.46	100	*	*
Albright (WV)	419	105.80	26.47	1.61	3	611.33	36.20	.30	—	—	—	100	*	—
Ft Martin (WV)	556	106.51	26.56	1.60	7	639.08	37.85	.30	—	—	—	100	*	—
Harrison (WV)	1,126	120.45	29.56	3.35	1	611.35	36.20	.22	57	750.28	7.50	100	*	*
Rivesville (WV)	255	121.35	28.53	1.03	2	688.37	40.77	.30	—	—	—	100	*	—
Willow Island (WV)	488	112.47	29.27	1.46	—	—	—	—	26	649.64	6.50	100	—	*
Pleasants (WV)	718	91.19	22.30	3.76	1	829.31	49.11	.30	96	584.45	5.84	99	*	1
Montana-Dakota Utilities	3,417	79.84	11.08	1.00	—	—	—	—	11	667.30	7.52	100	—	*
Heskett (ND)	561	96.00	13.57	.76	—	—	—	—	1	687.47	7.08	100	—	*
Lewis and Clark (MT)	307	94.93	12.42	.53	—	—	—	—	11	666.39	7.54	100	—	*
Coyote (ND)	2,550	74.53	10.37	1.11	—	—	—	—	—	—	—	100	—	—
Morgan City, City of	—	—	—	—	—	—	—	—	760	288.14	3.03	—	—	100
Morgan City (LA)	—	—	—	—	—	—	—	—	760	288.14	3.03	—	—	100
Muscatine Power and Water	951	87.73	14.53	.61	—	—	—	—	107	643.96	6.53	99	—	1
Muscatine (IA)	951	87.73	14.53	.61	—	—	—	—	107	643.96	6.53	99	—	1

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Nebraska Public Power System	6,606	51.79	8.89	0.31	5	715.94	41.54	0.10	173	474.48	4.74	100	*	*
Sheldon (NE)	899	65.15	11.20	.32	2	690.01	40.03	.10	7	556.51	5.57	100	*	*
Gerald Gentleman (NE)	5,707	49.69	8.52	.30	3	729.15	42.30	.10	166	470.88	4.71	100	*	*
Nevada Power	2,154	118.13	27.98	.59	9	585.06	34.18	.30	34,540	867.83	8.88	59	*	41
Clark (NV)	—	—	—	—	—	—	—	—	31,202	871.13	8.92	—	—	100
Gardner (NV)	2,154	118.13	27.98	.59	9	585.06	34.18	.30	—	—	—	100	*	—
Sunrise (NV)	—	—	—	—	—	—	—	—	3,339	837.06	8.58	—	—	100
New Orleans Public Service	—	—	—	—	580	436.47	28.50	1.50	22,135	406.89	4.22	—	14	86
Paterson (LA)	—	—	—	—	1	602.68	35.64	.50	2,521	384.61	3.98	—	*	100
Michoud (LA)	—	—	—	—	579	436.12	28.48	1.50	19,615	409.75	4.25	—	16	84
Northern Indiana Public Service	9,133	126.48	25.36	1.28	—	—	—	—	1,294	495.56	5.06	99	—	1
Bailly (IN)	1,403	142.67	32.25	2.63	—	—	—	—	92	610.80	6.23	100	—	*
Mitchell (IN)	1,008	126.44	23.31	.29	—	—	—	—	536	469.88	4.78	97	—	3
Michigan City (IN)	1,427	122.14	23.26	.38	—	—	—	—	472	474.45	4.85	98	—	2
Rollin Schahfer (IN)	5,295	122.75	24.48	1.36	—	—	—	—	194	563.36	5.76	100	—	*
Northern States Power	13,255	94.62	16.70	.44	13	685.60	39.79	.40	993	487.77	4.92	100	*	*
Black Dog (MN)	661	100.77	17.81	.20	—	—	—	—	221	492.06	4.96	98	—	2
High Bridge (MN)	781	92.35	16.55	.20	—	—	—	—	455	513.65	5.20	97	—	3
King (MN)	1,742	102.59	18.27	.37	—	—	—	—	21	384.66	3.89	100	—	*
Riverside (MN)	1,310	94.16	16.88	.20	—	—	—	—	38	481.15	4.85	100	—	*
Bay Front (WI)	166	146.32	29.69	.30	—	—	—	—	258	447.72	4.50	95	—	5
Sherburne County (MN)	8,595	91.62	16.03	.53	13	685.60	39.79	.40	—	—	—	100	*	—
Ohio Power	15,598	143.01	34.03	2.38	133	625.36	36.34	.02	—	—	—	100	*	—
Muskingum (OH)	3,348	131.82	31.21	2.28	29	662.38	38.47	.03	—	—	—	100	*	—
Kammer (WV)	1,523	112.14	29.17	1.46	5	640.02	37.53	.02	—	—	—	100	*	—
Mitchell (WV)	3,500	146.96	35.74	.80	43	672.08	39.06	.00	—	—	—	100	*	—
Gavin (OH)	7,226	153.61	35.53	3.39	55	567.16	32.93	.04	—	—	—	100	*	—
Ohio Valley Electric Corp	2,554	106.60	26.48	2.15	13	667.25	38.08	.36	—	—	—	100	*	—
Kyger Creek (OH)	2,554	106.60	26.48	2.15	13	667.25	38.08	.36	—	—	—	100	*	—
Oklahoma Gas and Electric	8,609	78.20	13.71	.25	15	577.29	34.51	.00	64,329	477.26	4.95	69	*	31
Horseshoe Lake (OK)	—	—	—	—	—	—	—	—	11,442	411.46	4.27	—	—	100
Muskogee (OK)	5,166	78.39	13.75	.25	—	—	—	—	2,145	429.01	4.45	98	—	2
Mustang (OK)	—	—	—	—	—	—	—	—	8,912	423.29	4.39	—	—	100
Seminole (OK)	—	—	—	—	—	—	—	—	41,830	509.23	5.28	—	—	100
Sooner (OK)	3,443	77.92	13.66	.25	15	577.29	34.51	.00	—	—	—	100	*	—
Omaha Public Power District	5,239	57.85	9.89	.31	5	598.96	34.72	.20	294	441.53	4.46	100	*	*
North Omaha (NE)	2,263	61.08	10.56	.31	—	—	—	—	294	441.53	4.46	99	—	1
Nebraska City (NE)	2,975	55.35	9.38	.32	5	598.96	34.72	.20	—	—	—	100	*	—
Orlando Utilities Comm	2,544	166.09	42.26	1.20	8	495.44	30.72	.68	—	—	—	100	*	—
Stanton Energy (FL)	2,544	166.09	42.26	1.20	8	495.44	30.72	.68	—	—	—	100	*	—
Orrville, City of	180	102.95	23.95	3.89	—	—	—	—	—	—	—	100	—	—
Orrville (OH)	180	102.95	23.95	3.89	—	—	—	—	—	—	—	100	—	—
Otter Tail Power	2,693	107.85	18.51	.33	—	—	—	—	—	—	—	100	—	—
Hoot Lake (MN)	511	125.70	23.25	.35	—	—	—	—	—	—	—	100	—	—
Big Stone (SD)	2,182	103.27	17.41	.33	—	—	—	—	—	—	—	100	—	—
Owensboro Municipal Utilities	1,139	90.95	19.49	3.25	8	506.45	29.78	*	—	—	—	99	1	—
Smith (KY)	1,139	90.95	19.49	3.25	8	506.45	29.78	*	—	—	—	99	1	—
Pacific Gas and Electric	—	—	—	—	369	594.98	37.18	1.10	9,982	587.71	5.99	—	18	82
Humboldt Bay (CA)	—	—	—	—	369	594.98	37.18	1.10	5,571	464.33	4.74	—	29	71
Hunters Point (CA)	—	—	—	—	—	—	—	—	4,411	743.93	7.58	—	—	100
PacifiCorp	22,216	87.36	17.25	.54	83	694.00	40.81	.30	11,488	460.72	4.85	97	*	3
Carbon (UT)	561	59.17	14.41	.48	—	—	—	—	—	—	—	100	—	—
Gadsby (UT)	—	—	—	—	—	—	—	—	11,083	463.59	4.88	—	—	100
Johnston (WY)	3,239	56.24	9.41	.35	12	749.23	44.05	.30	—	—	—	100	*	—
Naughton (WY)	2,266	96.60	19.09	.97	—	—	—	—	405	381.76	4.01	99	—	1
Wyodak (WY)	1,929	74.02	11.93	.60	8	743.19	43.70	.30	—	—	—	100	*	—

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
PacifiCorp														
Emery-Hunter (UT)	3,499	90.47	21.20	0.54	18	671.59	39.49	0.30	—	—	—	100	*	—
Jim Bridger (WY)	8,451	104.89	19.66	.53	21	726.04	42.69	.30	—	—	—	100	*	—
Huntington (UT)	2,271	69.72	16.74	.42	24	638.77	37.56	.30	—	—	—	100	*	—
Painesville Electric Light Dept	88	137.72	34.09	2.50	—	—	—	—	22	863.76	8.64	99	—	1
Painesville (OH)	88	137.72	34.09	2.50	—	—	—	—	22	863.76	8.64	99	—	1
Pasadena Water and Power Dept	—	—	—	—	—	—	—	—	2,079	1,087.14	11.13	—	—	100
Broadway (CA)	—	—	—	—	—	—	—	—	2,079	1,087.14	11.13	—	—	100
Philadelphia Electric	208	155.31	40.71	1.91	637	372.62	23.40	.46	120	851.43	8.87	57	42	1
Cromby (PA)	13	163.65	41.84	2.28	174	243.82	15.58	.65	36	720.50	7.50	22	75	2
Delaware (PA)	—	—	—	—	2	576.23	33.84	.19	—	—	—	—	100	—
Eddystone (PA)	195	154.77	40.63	1.89	461	421.58	26.30	.39	84	906.48	9.45	63	36	1
Plains Elec Gen and Trans Coop	533	135.12	24.75	.83	—	—	—	—	114	658.03	5.55	99	—	1
Escalante (NM)	533	135.12	24.75	.83	—	—	—	—	114	658.03	5.55	99	—	1
Platte River Authority	1,312	61.65	10.89	.23	21	612.24	35.38	.27	—	—	—	99	1	—
Rawhide (CO)	1,312	61.65	10.89	.23	21	612.24	35.38	.27	—	—	—	99	1	—
Portland General Electric	2,583	110.99	19.33	.38	337	636.17	37.41	.07	43,147	374.91	3.82	49	2	48
Boardman (OR)	2,583	110.99	19.33	.38	—	—	—	—	—	—	—	100	—	—
Coyote Springs (OR)	—	—	—	—	—	—	—	—	13,100	302.76	3.09	—	—	100
Beaver (OR)	—	—	—	—	337	636.17	37.41	.07	30,047	406.36	4.14	—	6	94
Power Authority State of NY	—	—	—	—	2,736	416.89	26.01	.21	18,058	471.59	4.79	—	48	52
Poletti (NY)	—	—	—	—	2,665	414.66	25.90	.21	10,147	327.54	3.34	—	62	38
Richard Flynn (NY)	—	—	—	—	71	504.54	29.85	.14	7,911	658.30	6.64	—	5	95
Public Serv Co of New Hampshire	1,710	167.22	43.52	1.34	934	336.71	21.56	.81	495	238.70	2.56	87	12	1
Merrimack (NH)	1,125	165.30	43.54	1.68	3	581.48	33.65	.27	—	—	—	100	*	—
Schiller (NH)	585	171.02	43.48	.67	—	—	—	—	—	—	—	100	—	—
Newington Station (NH)	—	—	—	—	931	335.95	21.52	.82	495	238.70	2.56	—	92	8
Public Serv Co of Oklahoma	3,272	115.91	20.27	.39	140	621.96	36.57	.00	70,207	423.22	4.34	44	1	55
Northeastern (OK)	3,272	115.91	20.27	.39	11	634.60	37.31	.00	21,378	378.16	3.86	72	*	28
Southwestern (OK)	—	—	—	—	40	556.13	32.70	.00	9,768	458.29	4.77	—	2	98
Tulsa (OK)	—	—	—	—	—	—	—	—	2,941	416.30	4.26	—	—	100
Riverside (OK)	—	—	—	—	88	650.00	38.22	.00	26,548	429.75	4.38	—	2	98
Comanche (CS) (OK)	—	—	—	—	—	—	—	—	9,572	470.98	4.86	—	—	100
Public Service Co of Colorado	10,484	89.18	17.09	.39	—	—	—	—	34,601	369.82	3.77	85	—	15
Arapahoe (CO)	857	80.64	14.13	.29	—	—	—	—	1,474	403.93	4.01	91	—	9
Cameo (CO)	296	96.72	21.44	.48	—	—	—	—	95	658.34	6.69	99	—	1
Cherokee (CO)	2,057	97.12	22.02	.49	—	—	—	—	2,203	397.88	3.94	96	—	4
Comanche (CO)	2,492	64.52	11.09	.32	—	—	—	—	104	416.65	4.16	100	—	*
Valmont (CO)	590	111.53	24.19	.41	—	—	—	—	204	416.06	4.11	98	—	2
Zuni (CO)	—	—	—	—	—	—	—	—	1,167	473.82	4.69	—	—	100
Hayden (CO)	1,666	100.90	20.96	.42	—	—	—	—	13	234.40	2.56	100	—	*
Fort St. Vrain (CO)	—	—	—	—	—	—	—	—	29,292	360.68	3.69	—	—	100
Pawnee (CO)	2,525	90.91	15.30	.36	—	—	—	—	49	425.17	4.34	100	—	*
Public Service Co of Indiana	16,542	110.30	24.35	1.65	176	602.40	34.66	.30	—	—	—	100	*	—
Cayuga (IN)	3,178	124.69	27.25	.95	21	684.44	39.38	.30	—	—	—	100	*	—
Edwardsport (IN)	351	108.51	24.17	1.47	10	615.06	35.39	.30	—	—	—	99	1	—
Noblesville (IN)	185	145.36	30.55	1.55	2	574.07	33.03	.30	—	—	—	100	*	—
Gallagher (IN)	1,259	127.73	30.89	1.91	51	597.52	34.38	.30	—	—	—	99	1	—
Wabash River (IN)	2,121	107.67	23.10	1.49	32	614.73	35.37	.30	—	—	—	100	*	—
Gibson Station (IN)	9,447	102.92	22.67	1.90	61	570.65	32.84	.30	—	—	—	100	*	—
Public Service Co of New Mexico	6,118	184.67	35.25	.70	29	631.49	36.07	1.00	5,458	527.67	5.41	95	*	5
Reeves (NM)	—	—	—	—	—	—	—	—	5,458	527.67	5.41	—	—	100
San Juan (NM)	6,118	184.67	35.25	.70	29	631.49	36.07	1.00	—	—	—	100	*	—
Richmond Power and Light	321	152.50	35.78	2.08	—	—	—	—	—	—	—	100	—	—
Whitewater (IN)	321	152.50	35.78	2.08	—	—	—	—	—	—	—	100	—	—
Rochester Dept Public Utilities	191	184.21	42.94	.96	—	—	—	—	269	645.35	6.53	94	—	6
Silver Lake (MN)	191	184.21	42.94	.96	—	—	—	—	269	645.35	6.53	94	—	6

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Rochester Gas and Electric Corp	660	140.50	36.90	2.06	—	—	—	—	—	—	—	100	—	—
Russell Station 7 (NY)	660	140.50	36.90	2.06	—	—	—	—	—	—	—	100	—	—
Ruston Util Sys	—	—	—	—	—	—	—	—	991	421.16	4.38	—	—	100
Steam Plant (LA)	—	—	—	—	—	—	—	—	991	421.16	4.38	—	—	100
Sacramento Municipal Utility Di	—	—	—	—	—	—	—	—	22,773	657.01	6.57	—	—	100
Central Valley (CA)	—	—	—	—	—	—	—	—	5,363	652.68	6.53	—	—	100
SCA Cogen Proj (CA)	—	—	—	—	—	—	—	—	7,211	669.75	6.70	—	—	100
SPA Cogen Proj (CA)	—	—	—	—	—	—	—	—	10,199	650.28	6.50	—	—	100
Salt River Project	11,689	119.84	25.32	.51	282	702.76	41.27	0.31	32,285	422.88	4.30	88	1	12
Agua Fria (AZ)	—	—	—	—	204	713.10	41.93	.32	17,055	423.53	4.27	—	7	93
Kyrene (AZ)	—	—	—	—	22	709.67	41.76	.10	3,678	535.93	5.52	—	3	97
Navajo (AZ)	8,223	117.14	25.56	.53	26	647.52	37.65	.31	—	—	—	100	*	—
Coronado (AZ)	3,466	127.01	24.74	.46	5	728.09	42.07	.05	—	—	—	100	*	—
Santan (AZ)	—	—	—	—	25	665.50	39.13	.50	11,551	385.79	3.96	—	1	99
San Miguel Electric	3,282	79.59	8.28	2.06	—	—	—	—	—	—	—	100	—	—
San Miquel (TX)	3,282	79.59	8.28	2.06	—	—	—	—	—	—	—	100	—	—
Savannah Electric and Power	723	152.20	38.07	.73	1	638.19	36.99	.50	1,064	331.41	3.39	94	*	6
Kraft (GA)	436	142.18	35.62	.74	—	—	—	—	1,056	330.43	3.38	91	—	9
Riverside (GA)	—	—	—	—	—	—	—	—	8	461.28	4.72	—	—	100
McIntosh (GA)	287	167.45	41.79	.72	1	638.19	36.99	.50	—	—	—	100	*	—
Seminole Electric Coop	3,301	180.24	43.99	2.79	42	577.70	33.39	.27	—	—	—	100	*	—
Seminole (FL)	3,301	180.24	43.99	2.79	42	577.70	33.39	.27	—	—	—	100	*	—
Sierra Pacific Power	968	157.44	35.38	.40	—	—	—	—	12,100	595.84	6.11	64	—	36
Fort Churchill (NV)	—	—	—	—	—	—	—	—	4,484	597.86	6.08	—	—	100
Tracy (NV)	—	—	—	—	—	—	—	—	4,415	597.17	6.18	—	—	100
Pinon Pine (NV)	—	—	—	—	—	—	—	—	3,201	591.19	6.07	—	—	100
North Valmy (NV)	968	157.44	35.38	.40	—	—	—	—	—	—	—	100	—	—
Sikeston Brd of Mun Utilities	802	108.55	19.04	.34	3	645.75	38.24	.15	—	—	—	100	*	—
Sikeston (MO)	802	108.55	19.04	.34	3	645.75	38.24	.15	—	—	—	100	*	—
South Carolina Electric and Gas	6,695	155.77	39.10	1.05	119	592.45	34.34	.20	798	256.70	2.64	99	*	*
Canadys (SC)	997	160.31	40.40	1.26	34	595.82	34.53	.20	146	323.60	3.33	99	1	1
Mcmeekin (SC)	631	158.83	38.70	1.01	2	509.36	29.52	.20	139	225.40	2.32	99	*	1
Urguhart (SC)	639	153.70	40.14	1.37	3	608.04	35.24	.20	511	244.20	2.51	97	*	3
Wateree (SC)	1,857	158.97	39.54	1.12	49	585.37	33.93	.20	—	—	—	99	1	—
Williams (SC)	1,568	152.36	39.46	.81	26	604.03	35.01	.20	2	719.66	7.40	100	*	*
Cope (SC)	1,003	150.13	36.04	.94	5	604.14	35.02	.20	—	—	—	100	*	—
South Carolina Public Serv Auth	7,876	154.99	39.20	1.26	—	—	—	—	—	—	—	100	—	—
Cross (SC)	3,282	153.98	39.22	1.32	—	—	—	—	—	—	—	100	—	—
Grainger (SC)	422	171.53	42.33	1.35	—	—	—	—	—	—	—	100	—	—
Jefferies (SC)	732	166.33	41.76	1.38	—	—	—	—	—	—	—	100	—	—
Winyah (SC)	3,440	151.58	38.24	1.17	—	—	—	—	—	—	—	100	—	—
South Mississippi Elec Pwr Assn	1,027	152.51	37.45	.96	9	561.04	33.27	.33	4,826	460.72	4.76	83	*	16
Moselle (MS)	—	—	—	—	—	—	—	—	4,826	460.72	4.76	—	—	100
R D Morrow (MS)	1,027	152.51	37.45	.96	9	561.04	33.27	.33	—	—	—	100	*	—
Southern California Edison	4,933	123.70	27.12	.49	—	—	—	—	295	1,652.66	16.93	100	—	*
Mohave (NV)	4,933	123.70	27.12	.49	—	—	—	—	295	1,652.66	16.93	100	—	*
Southern Illinois Power Coop	960	90.44	18.39	2.97	10	698.56	39.81	.04	—	—	—	100	*	—
Marion (IL)	960	90.44	18.39	2.97	10	698.56	39.81	.04	—	—	—	100	*	—
Southern Indiana Gas and Elec	2,161	100.99	23.04	3.26	—	—	—	—	154	602.80	6.22	100	—	*
Culley (IN)	857	97.93	22.14	4.06	—	—	—	—	31	760.91	7.86	100	—	*
A B Brown (IN)	1,015	100.60	23.03	3.05	—	—	—	—	106	552.73	5.70	100	—	*
Warrick (IN)	289	111.18	25.75	1.67	—	—	—	—	16	627.43	6.48	100	—	*
Southwestern Electric Pwr	11,883	150.44	24.11	.64	191	635.03	38.65	.09	33,966	416.66	4.34	84	1	16
Arsenal Hill (LA)	—	—	—	—	—	—	—	—	1,556	400.08	4.36	—	—	100
Lieberman (LA)	—	—	—	—	38	617.51	38.88	.10	2,862	452.17	4.56	—	8	92

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
Southwestern Electric Pwr														
Knox Lee (TX)	—	—	—	—	75	679.48	42.08	0.09	9,906	425.79	4.41	—	4	96
Lone Star (TX)	—	—	—	—	—	—	—	—	223	335.90	3.47	—	—	100
Wilkes (TX)	—	—	—	—	39	615.07	36.17	.10	19,151	408.26	4.27	—	1	99
Flint Creek (AR)	1,901	148.92	25.21	0.35	9	639.78	37.62	.09	—	—	—	100	*	—
Welsh Station (TX)	6,852	149.06	25.44	.32	29	563.54	33.14	.03	—	—	—	100	*	—
Pirkey (TX)	3,130	155.52	20.53	1.53	—	—	—	—	268	481.34	5.24	99	—	1
Southwestern Public Service	**8,563**	**137.93**	**24.22**	**.27**	—	—	—	—	**71,543**	**415.44**	**4.20**	**68**	—	**32**
Maddox (NM)	—	—	—	—	—	—	—	—	7,298	393.35	4.00	—	—	100
Cunningham (NM)	—	—	—	—	—	—	—	—	15,022	406.43	4.11	—	—	100
Jones (TX)	—	—	—	—	—	—	—	—	26,898	419.52	4.25	—	—	100
Moore (TX)	—	—	—	—	—	—	—	—	391	357.85	3.77	—	—	100
Nichols (TX)	—	—	—	—	—	—	—	—	10,928	414.12	4.15	—	—	100
Plant X (TX)	—	—	—	—	—	—	—	—	10,788	433.19	4.39	—	—	100
Riverview (TX)	—	—	—	—	—	—	—	—	48	430.85	4.32	—	—	100
Harrington (TX)	4,533	119.57	21.14	.26	—	—	—	—	105	527.15	5.40	100	—	*
Tolk (TX)	4,031	158.88	27.69	.27	—	—	—	—	65	743.92	7.49	100	—	*
Springfield Wtr Lt and Pwr Dept	**1,222**	**116.42**	**24.33**	**2.77**	—	—	—	—	—	—	—	**100**	—	—
Dallman (IL)	1,065	113.84	23.85	3.05	—	—	—	—	—	—	—	100	—	—
Lakeside (IL)	157	134.29	27.58	.86	—	—	—	—	—	—	—	100	—	—
St Joseph Light and Power	**423**	**113.80**	**22.12**	**.34**	**1**	**720.12**	**41.87**	**.40**	**994**	**375.03**	**3.74**	**89**	*	**11**
Lakeroad (MO)	423	113.80	22.12	.34	1	720.12	41.87	.40	994	375.03	3.74	89	*	11
Sunflower Electric Power Corp	**1,363**	**104.90**	**17.76**	**.31**	—	—	—	—	**1,757**	**377.78**	**3.67**	**93**	—	**7**
Holcomb (KS)	1,363	104.90	17.76	.31	—	—	—	—	74	467.18	4.55	100	—	*
Garden City (KS)	—	—	—	—	—	—	—	—	1,684	373.86	3.63	—	—	100
Tallahassee, City of	—	—	—	—	—	—	—	—	**14,798**	**442.11**	**4.62**	—	—	**100**
Hopkins (FL)	—	—	—	—	—	—	—	—	5,554	442.27	4.63	—	—	100
Purdom (FL)	—	—	—	—	—	—	—	—	9,244	442.01	4.61	—	—	100
Tampa Electric[4]	**7,329**	**155.77**	**36.04**	**2.21**	**1,344**	**475.50**	**29.62**	**.73**	—	—	—	**96**	**4**	—
Big Bend (FL)	—	—	—	—	30	587.63	34.06	.05	—	—	—	96	4	—
Gannon (FL)	301	175.16	44.26	1.20	57	553.87	32.10	.03	—	—	—	96	4	—
Hookers Point (FL)	—	—	—	—	1,023	446.28	28.41	.95	—	—	—	—	100	—
Polk Station (FL)	—	—	—	—	234	582.53	33.76	.05	—	—	—	—	100	—
Davant Transfer (FL)	7,029	154.86	35.69	2.25	—	—	—	—	—	—	—	100	—	—
Taunton Municipal Lighting Plant	—	—	—	—	**86**	**420.13**	**26.51**	**.46**	**1,398**	**386.37**	**4.00**	—	**27**	**73**
Cleary (MA)	—	—	—	—	86	420.13	26.51	.46	1,398	386.37	4.00	—	27	73
Tennessee Valley Authority[5]	**36,556**	**121.92**	**27.99**	**1.70**	**137**	**559.49**	**32.87**	**.50**	—	—	—	**100**	*	—
Colbert (AL)	1,075	136.25	32.42	1.39	—	—	—	—	—	—	—	100	—	—
Widows Creek (AL)	3,084	139.50	33.22	2.36	18	583.36	34.28	.50	—	—	—	100	*	—
Paradise (KY)	4,779	96.29	20.21	3.86	7	588.71	34.59	.50	—	—	—	100	*	—
Shawnee (KY)	3,379	133.25	30.51	.55	15	554.00	32.55	.50	—	—	—	100	*	—
Allen (TN)	—	—	—	—	1	616.86	36.25	.50	—	—	—	—	100	—
Bull Run (TN)	2,104	135.74	33.72	.96	26	510.97	30.02	.50	—	—	—	100	*	—
Cumberland (TN)	6,032	108.54	26.05	2.76	49	559.33	32.87	.50	—	—	—	100	*	—
Gallatin (TN)	16	117.21	29.69	2.43	—	—	—	—	—	—	—	100	—	—
Sevier (TN)	1,780	132.97	33.81	.91	2	632.59	37.17	.50	—	—	—	100	*	—
Johnsonville (TN)	8	172.29	41.62	1.29	2	696.90	40.95	.50	—	—	—	95	5	—
Kingston (TN)	3,408	131.45	32.28	1.05	18	574.11	33.73	.50	—	—	—	100	*	—
GRT Terminal (TN)	8,951	122.19	26.69	.95	—	—	—	—	—	—	—	100	—	—
Cora Transfer (TN)	1,939	119.16	24.87	.35	—	—	—	—	—	—	—	100	—	—
Terrebonne Parish Consol	—	—	—	—	—	—	—	—	**946**	**390.31**	**4.16**	—	—	**100**
Houma (LA)	—	—	—	—	—	—	—	—	946	390.31	4.16	—	—	100
Texas Municipal Power	**2,089**	**134.41**	**22.71**	**.31**	—	—	—	—	**26**	**379.60**	**3.87**	**100**	—	*
Gibbons Creek (TX)	2,089	134.41	22.71	.31	—	—	—	—	26	379.60	3.87	100	—	*
Texas New Mexico Power Co.	**1,881**	**150.68**	**20.37**	**.93**	—	—	—	—	**321**	**338.89**	**3.45**	**99**	—	**1**
TNP One (TX)	1,881	150.68	20.37	.93	—	—	—	—	321	338.89	3.45	99	—	1
TXU Electric Co	**27,297**	**131.74**	**18.01**	**.79**	**945**	**687.85**	**40.02**	*	**273,845**	**425.09**	**4.36**	**57**	**1**	**43**
Lake Hubbard (TX)	—	—	—	—	59	699.40	40.54	.00	20,038	425.71	4.32	—	2	98

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
TXU Electric Co														
Mountain Creek (TX)	—	—	—	—	—	—	—	—	18,532	428.00	4.37	—	—	100
North Lake (TX)	—	—	—	—	135	699.40	40.54	0.00	13,335	413.04	4.25	—	5	95
Parkdale (TX)	—	—	—	—	—	—	—	—	3,476	379.88	3.83	—	—	100
Eagle Mountain (TX)	—	—	—	—	—	—	—	—	7,391	388.64	3.94	—	—	100
Graham (TX)	—	—	—	—	—	—	—	—	12,078	398.40	4.03	—	—	100
Handley (TX)	—	—	—	—	99	699.40	40.54	.00	20,880	432.98	4.44	—	3	97
Morgan Creek (TX)	—	—	—	—	—	—	—	—	22,909	441.51	4.65	—	—	100
North Main (TX)	—	—	—	—	—	—	—	—	251	310.33	3.17	—	—	100
Permian Basin (TX)	—	—	—	—	—	—	—	—	24,378	424.54	4.42	—	—	100
Big Brown (TX)	5,383	149.31	21.87	0.60	—	—	—	—	173	338.94	3.54	100	—	*
Collin (TX)	—	—	—	—	—	—	—	—	2,117	388.04	3.93	—	—	100
Lake Creek (TX)	—	—	—	—	390	695.49	40.31	.00	5,557	416.97	4.28	—	28	72
River Crest (TX)	—	—	—	—	—	—	—	—	143	317.07	3.35	—	—	100
Stryker (TX)	—	—	—	—	50	624.30	38.81	.00	17,472	448.45	4.61	—	2	98
Tradinghouse (TX)	—	—	—	—	—	—	—	—	46,026	420.39	4.31	—	—	100
Trinidad (TX)	—	—	—	—	—	—	—	—	4,333	420.91	4.30	—	—	100
Valley (TX)	—	—	—	—	25	699.40	40.54	.00	24,503	426.54	4.33	—	1	99
Martin Lake (TX)	11,604	113.34	15.41	1.10	40	618.56	35.85	.02	—	—	—	100	*	—
Monticello (TX)	9,474	144.69	19.23	.50	32	631.55	36.60	.01	—	—	—	100	*	—
Sandow No 4 (TX)	836	121.24	15.62	1.08	—	—	—	—	—	—	—	100	—	—
Decordova (TX)	—	—	—	—	115	699.40	40.54	.00	30,252	433.97	4.45	—	2	98
Tri-State G & T Assn Inc.	**4,920**	**108.39**	**22.15**	**.42**	**18**	**890.68**	**45.77**	**.24**	**52**	**290.69**	**3.25**	**100**	*	*
Nucla (CO)	365	112.80	24.06	.97	—	—	—	—	—	—	—	99	1	—
Craig (CO)	4,555	108.02	21.99	.38	18	890.68	45.77	.24	52	290.69	3.25	100	*	*
Tucson Electric Power Co	**3,670**	**141.52**	**26.71**	**.83**	**13**	**496.52**	**29.55**	**.04**	**12,415**	**517.76**	**5.27**	**84**	*	**15**
Irvington (AZ)	339	198.46	43.79	.48	—	—	—	—	12,415	517.76	5.27	37	—	63
Springerville (AZ)	3,331	134.64	24.97	.86	13	496.52	29.55	.04	—	—	—	100	*	—
United Power Association	**937**	**74.36**	**9.94**	**.72**	—	—	—	—	—	—	—	**100**	—	—
Stanton (ND)	937	74.36	9.94	.72	—	—	—	—	—	—	—	100	—	—
UtiliCorp United Inc	**1,683**	**93.30**	**18.15**	**.33**	—	—	—	—	—	—	—	**100**	—	—
Sibley (MO)	1,683	93.30	18.15	.33	—	—	—	—	—	—	—	100	—	—
Vero Beach Municipal Utilities	—	—	—	—	**343**	**673.08**	**40.86**	**.58**	**2,106**	**332.65**	**3.47**	—	**49**	**51**
Vero Beach (FL)	—	—	—	—	343	673.08	40.86	.58	2,106	332.65	3.47	—	49	51
Vineland, City of	**27**	**186.97**	**48.80**	**.92**	**64**	**453.98**	**28.60**	**.54**	—	—	—	**63**	**37**	—
H M Down (NJ)	27	186.97	48.80	.92	64	453.98	28.60	.54	—	—	—	63	37	—
Virginia Electric and Power	**11,701**	**151.80**	**38.09**	**1.24**	**7,328**	**357.88**	**22.59**	**1.03**	**8,245**	**438.10**	**4.53**	**84**	**13**	**2**
Bremo Bluff (VA)	508	173.33	43.55	.98	6	581.78	34.21	.20	—	—	—	100	*	—
Chesterfield (VA)	2,451	171.12	44.10	1.04	445	615.30	36.18	.20	7,744	443.78	4.59	86	4	11
Chesapeake Energy (VA)	1,268	177.28	45.77	.88	22	582.31	34.24	.20	—	—	—	100	*	—
Possum Point (VA)	815	161.66	40.15	.97	2,234	359.34	22.68	.69	—	—	—	59	41	—
Yorktown (VA)	681	159.37	41.45	1.49	3	574.27	33.77	.20	500	350.40	3.64	97	*	3
Mount Storm (WV)	3,336	118.91	28.94	1.59	70	630.28	37.06	.20	—	—	—	99	1	—
Clover (VA)	2,367	156.91	39.95	1.07	4	580.30	34.12	.09	—	—	—	100	*	—
North Branch (VA)	273	96.82	19.43	2.75	—	—	—	—	—	—	—	99	1	—
Storage Facility # 1	—	—	—	—	4,544	328.40	20.90	1.30	—	—	—	—	100	—
West Penn Power (APS)	**542**	**107.01**	**27.44**	**2.20**	**1**	**569.03**	**33.70**	**.30**	—	—	—	**100**	*	—
Hatfield (PA)	542	107.01	27.44	2.20	1	569.03	33.70	.30	—	—	—	100	*	—
West Texas Utilities	**2,084**	**133.33**	**22.53**	**.35**	**143**	**694.75**	**40.85**	**.09**	**30,371**	**415.83**	**4.22**	**53**	**1**	**46**
Oklaunion (TX)	2,084	133.33	22.53	.35	—	—	—	—	—	—	—	100	—	—
Oak Creek (TX)	—	—	—	—	—	—	—	—	3,077	414.97	4.23	—	—	100
Paint Creek (TX)	—	—	—	—	16	689.90	40.57	.00	3,353	401.22	4.14	—	3	97
Rio Pecos (TX)	—	—	—	—	—	—	—	—	4,727	407.31	4.13	—	—	100
San Angelo (TX)	—	—	—	—	—	—	—	—	6,272	448.39	4.41	—	—	100
Fort Phantom (TX)	—	—	—	—	127	695.36	40.89	.10	12,941	407.74	4.17	—	5	95
Western Farmers Electric Coop	**1,748**	**108.00**	**18.88**	**.28**	**87**	**660.30**	**39.09**	**.10**	**11,758**	**437.14**	**4.50**	**71**	**1**	**28**
Anadarko (OK)	—	—	—	—	87	660.30	39.09	.10	8,966	442.51	4.55	—	5	95
Mooreland (OK)	—	—	—	—	—	—	—	—	2,792	419.98	4.34	—	—	100
Hugo (OK)	1,748	108.00	18.88	.28	—	—	—	—	—	—	—	100	—	—

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

Table 31. Receipts, Average Delivered Cost, and Quality of Fossil Fuels by Electric Utility and Plant, 2001 (Continued)

Electric Utility Plant (State)	Coal				Petroleum[1]				Gas			% of Total Btu		
	Receipts (1,000 Short Tons)	Cost (cents per MM Btu)	Cost ($ per Short Ton)	(% Avg. Sulfur)	Receipts (1,000 bbls)	Cost (cents per MM Btu)	Cost ($ per bbl)	(% Avg. Sulfur)	Receipts (1,000 Mcf)	Cost (cents per MM Btu)	Cost ($ per Mcf)	Coal	Petroleum	Gas
WestPlains Energy	—	—	—	—	—	—	—	—	5,746	367.30	3.66	—	—	100
Cimarron River (KS)	—	—	—	—	—	—	—	—	1,171	359.98	3.53	—	—	100
Large (KS)	—	—	—	—	—	—	—	—	3,883	381.74	3.82	—	—	100
Mullergren (KS)	—	—	—	—	—	—	—	—	692	298.32	2.98	—	—	100
Wisconsin Electric Power	11,868	102.91	19.29	0.38	16	569.66	33.23	0.26	991	475.05	4.82	100	*	*
Presque Isle (MI)	2,055	132.04	27.54	.44	16	569.66	33.23	.26	—	—	—	100	*	—
Oak Creek (WI)	3,362	100.14	18.32	.28	—	—	—	—	752	457.08	4.64	99	—	1
Port Washington (WI)	499	140.15	36.70	1.43	—	—	—	—	37	440.21	4.44	100	—	*
Valley (WI)	578	160.87	38.75	.43	—	—	—	—	72	475.59	4.80	100	—	*
Pleasant Prairie (WI)	5,373	76.86	13.02	.31	—	—	—	—	130	588.39	5.99	100	—	*
Wisconsin Power and Light	7,481	104.97	18.38	.32	106	647.49	38.07	.02	272	536.37	5.36	99	*	*
Blackhawk (WI)	—	—	—	—	—	—	—	—	272	536.37	5.36	—	—	100
Edgewater (WI)	2,462	119.45	21.51	.32	73	642.31	37.77	.02	—	—	—	99	1	—
Nelson Dewey (WI)	482	125.35	23.37	.33	12	719.89	42.33	.02	—	—	—	99	1	—
Rock River (WI)	—	—	—	—	5	646.33	38.00	.00	—	—	—	—	100	—
Columbia (WI)	4,537	94.35	16.15	.32	15	613.31	36.06	.02	—	—	—	100	*	—
Wisconsin Public Service Corp	3,546	104.96	18.67	.26	—	—	—	—	578	492.86	4.97	99	—	1
Pulliam (WI)	1,576	107.31	19.34	.22	—	—	—	—	419	484.43	4.88	99	—	1
Weston (WI)	1,970	103.03	18.13	.29	—	—	—	—	159	515.09	5.20	100	—	*
Wyandotte Dept of Mun Service	127	170.80	42.74	.81	—	—	—	—	32	612.31	6.12	99	—	1
Wyandotte (MI)	127	170.80	42.74	.81	—	—	—	—	32	612.31	6.12	99	—	1
Total	762,815	123.15	24.68	.89	114,523	392.05	24.86	1.09	2,152,366	448.65	4.61	84	4	12

1 Does not include petroleum coke receipts of 2,019,000 short tons at an average cost of 78.38 cents per million Btu.

2 Includes at least one delivery at a price of 1,000 cents per million Btu or greater. High price is frequently caused when fixed costs are averaged into a small quantity.

3 The cost reported under IMT Transfer (Louisiana) is the weighted average cost of coal delivered to this facility. Florida Power Corporation incurs additional costs for transporting coal from this transfer facility to the Crystal River power plant in Florida. This cost is not included in data shown in this report. When aggregated at the State level, data for this transfer facility are shown as though the coal were delivered to Florida.

4 The Tampa Electric Company reports coal destined for the Big Bend power plant in Florida as it is received at the Davant facility located in Louisiana. The cost reported under Davant Transfer is the weighted average cost of coal delivered to this facility. Tampa Electric incurs additional costs for transporting coal from Davant to the Big Bend plant. These costs are not included in data shown in this report. When aggregated at the State level, data for this transfer facility are shown as though the coal were delivered to Florida.

5 Coal reported as delivered to the Cora and GRT transfer facilities is later transferred to individual electric plants located in Alabama, Kentucky, and Tennessee. The cost of transportation from these facilities to the electric plants is not included in the costs shown in this report. Approximately 97 percent of the coal delivered to the Cora facility was transferred to the Allen plant in Tennessee. About 3 percent was transferred to plants in Alabama. Approximately 80 percent of the coal delivered to the GRT facility was transferred to plants in Tennessee. Approximately 19 percent was transferred to plants in Alabama. Less than 1 percent was transferred to plants in Kentucky.

* = Number less than 0.5.

Notes: • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. • Mcf = thousand cubic feet.• MM Btu = million Btu. • bbls = barrels.• Cost = average delivered cost.

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

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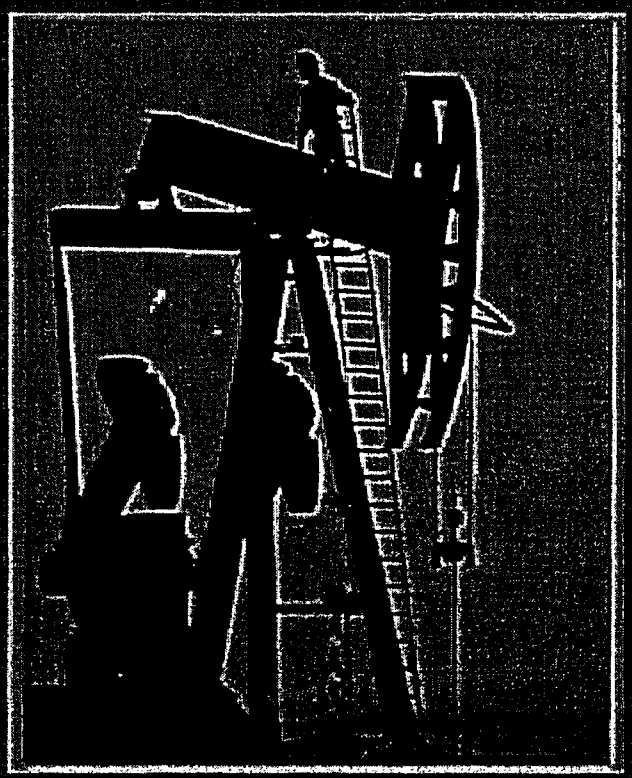

With Projections to 2025

Energy Information Administration

For Further Information . . .

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AEO2005 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early February 2005. Assumptions underlying the projections and tables of regional and other detailed results will also be available in early February 2005, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System (NEMS) and the report *NEMS: An Overview* are available at web site www.eia.doe.gov/bookshelf/docs.html and will be updated for *AEO2005* in the first few months of 2005.

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Preface

The *Annual Energy Outlook 2005* (*AEO2005*) presents midterm forecasts of energy supply, demand, and prices through 2025 prepared by the Energy Information Administration (EIA). The projections are based on results from EIA's National Energy Modeling System (NEMS).

The report begins with an "Overview" summarizing the *AEO2005* reference case. The next section, "Legislation and Regulations," discusses evolving legislation and regulatory issues, including legislation and regulations that have been enacted and some that are proposed. Next, the "Issues in Focus" section discusses key energy market issues and examines their potential impacts. In particular, it includes a discussion of the world oil price assumptions used in the reference case and four alternative world oil price cases examined in *AEO2005*. "Issues in Focus" is followed by "Market Trends," which provides a summary of energy market trends in the *AEO2005* forecast.

The analysis in *AEO2005* focuses primarily on a reference case, lower and higher economic growth cases, and four alternative oil price cases—a low world oil price case, an October oil futures case, and two high world oil price cases. Forecast tables for those cases are provided in Appendixes A through D. The major results for the alternative cases, which explore the impacts of varying key assumption in NEMS (such as rates of technology penetration), are summarized in Appendix E. Appendix F briefly describes NEMS and the alternative cases.

The *AEO2005* projections are based on Federal, State, and local laws and regulations in effect on or before October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation requiring funds that have not been appropriated) are not reflected in the projections. For example, the *AEO2005* forecast does not include the potential impacts of regulations proposed by the U.S. Environmental Protection Agency, such as the Clean Air Interstate Rule and the Clean Air Mercury Rule, that would address emissions from coal-fired power plants in the United States. In general, the historical data used for *AEO2005* projections are based on EIA's *Annual Energy Review 2003*, published in September 2004; however, data are taken from multiple sources. In some cases, only partial or preliminary 2003 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official data values. The projections for 2004 and 2005 incorporate the short-term projections from EIA's September 2004 *Short-Term Energy Outlook*.

Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors use the *AEO2005* projections. They are published in accordance with Section 205c of the Department of Energy Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

The projections in the *Annual Energy Outlook 2005* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of precision. Many key uncertainties in the *AEO2005* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

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Overview

Overview

Key Energy Issues to 2025

The Energy Information Administration (EIA), in preparing model forecasts for its *Annual Energy Outlook 2005* (*AEO2005*), evaluated a wide range of current trends and issues that could have major implications for U.S. energy markets over the 20-year forecast period, from 2005 to 2025. Trends in energy supply and demand are linked with such unpredictable factors as the performance of the U.S. economy overall, advances in technologies related to energy production and consumption, annual changes in weather patterns, and future public policy decisions [*1*]. Among the most important issues identified as having the potential to affect the complex behavior of the domestic energy economy, oil prices and natural gas supply were considered to be of particular significance in increasing the uncertainty associated with the *AEO2005* reference case projections.

World crude oil prices—defined by the U.S. average refiner's acquisition cost of imported crude oil (IRAC)—reached a recent low of $10.29 per barrel (in 2003 dollars) in December 1998. For the next 3 years, crude oil prices ranged between just under $20 and just over $30 per barrel. Since December 2001, however, prices have increased steadily, to about $46 per barrel in October 2004.

Strong growth in the demand for oil worldwide, particularly in China and other developing countries, is generally cited as the driving force behind the sharp price increases seen over the past 3 years. Other factors contributing to the upward trend include a tight supply situation that has shown only limited response to higher prices; changing views on the economics of oil production; concerns about economic and political situations in the Middle East, Venezuela, Nigeria, and the former Soviet Union; and recent supply disruptions caused by weather events (Hurricane Ivan). The future path of prices is a key uncertainty facing world oil markets.

The *AEO2005* reference case assumes that world crude oil prices will decline as growth in consumption slows and producers increase their productive capacity and output in response to current high prices. In contrast, the October 2004 prices from the New York Mercantile Exchange (NYMEX) futures market (corrected for the difference between futures prices and the IRAC) imply that the annual average price in 2005 will exceed the 2004 average price level, and that prices will then decline only slowly over the next few years, resulting in 2010 prices higher than those projected in the *AEO2005* reference case. To evaluate the uncertainty associated with the future path of world oil prices, *AEO2005* includes alternative world oil price cases. A summary of the alternative world oil price cases included in *AEO2005* is provided in "Issues in Focus," page 40.

From 1986 to 2000, when U.S. natural gas consumption grew from 16.2 trillion cubic feet to a high of 23.3 trillion cubic feet, 40 percent of the increased demand was met by imports, predominantly from Canada. Based on the latest assessment from Canada's National Energy Board, however, it is unlikely that future production from Canada will be able to support a continued increase in U.S. imports.

In the *AEO2005* reference case, U.S. natural gas consumption is projected to grow from 22 trillion cubic feet in 2003 to almost 31 trillion cubic feet in 2025. Most of the additional supply is expected to come from Alaska and imports of liquefied natural gas (LNG). A key issue for U.S. energy markets is whether the investments and regulatory approvals needed to make those natural gas supplies available will be forthcoming, and what the ramifications will be if they are not. The *AEO2005* includes a restricted natural gas supply case to examine the implications of a possible future in which no Alaska natural gas pipeline is built, no new construction is started on additional LNG terminals, and production technology advances more slowly than it has in the past. The restricted natural gas supply case is also described in "Issues in Focus," page 66.

The following sections summarize the key trends in the *AEO2005* reference case and compare them with last year's reference case (*AEO2004*). A summary of the *AEO2005* reference case is provided in Table 1 on page 9.

Economic Growth

In the *AEO2005* reference case, the U.S. economy, as measured by gross domestic product (GDP), grows at an average annual rate of 3.1 percent from 2003 to 2025, slightly higher than the growth rate of 3.0 percent per year for the same period in *AEO2004*. Many of the determinants of economic growth are similar to those in *AEO2004*, but there are some important differences. Both the Federal funds rate and the nominal yield on the 10-year Treasury note are higher in the early years of the *AEO2005* forecast but generally lower after 2010; the industrial value of shipments reflects a more pessimistic forecast for industrial output in view of the downward adjustment in domestic production for some manufacturing sectors in the early 2000s; and the U.S. population forecast in *AEO2005* is higher, following the adoption of the

interim population projections released by the U.S. Census Bureau in 2004.

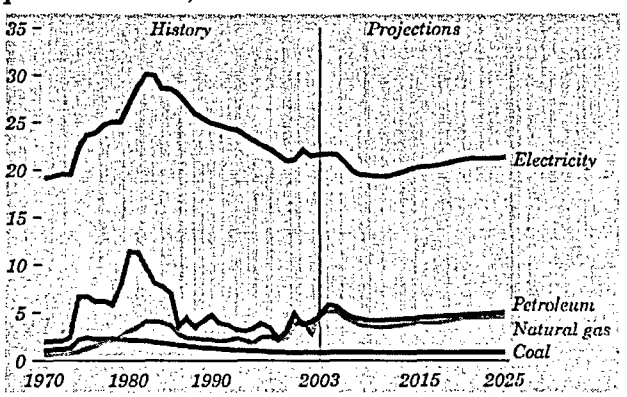
Energy Prices

In the *AEO2005* reference case, the annual average world oil price (IRAC) increases from $27.73 per barrel (2003 dollars) in 2003 to $35.00 per barrel in 2004 and then declines to $25.00 per barrel in 2010 as new supplies enter the market. It then rises slowly to $30.31 per barrel in 2025, about $3 per barrel higher than the *AEO2004* projection of $27.41 per barrel in 2025. In nominal dollars, the average world oil price is about $52 per barrel in 2025.

The *AEO2005* world oil price forecast is characterized by decreasing prices through 2010 and moderately increasing prices thereafter (Figure 1). This is consistent with a forecast that projects increases in world petroleum demand, from about 80 million barrels per day in 2003 to more than 120 million barrels per day in 2025, which is met by increased oil production both from the Organization of Petroleum Exporting Countries (OPEC) and from non-OPEC nations. *AEO2005* projects OPEC oil production of 55 million barrels per day in 2025, 80 percent higher than the 31 million barrels per day produced in 2003. The forecast assumes that OPEC will pursue policies intended to increase production, that sufficient resources exist, and that access and capital will be available to expand production. Non-OPEC oil production is expected to increase from 49 to 65 million barrels per day between 2003 and 2025.

Average wellhead prices for natural gas in the United States are projected generally to decrease, from $4.98 per thousand cubic feet (2003 dollars) in 2003 to $3.64 per thousand cubic feet in 2010 as the initial availability of new import sources and increased drilling expands available supply. After 2010, wellhead prices are projected to increase gradually (Figure 1), to $4.79 per thousand cubic feet in 2025 (equivalent to about $8.20 per thousand cubic feet in nominal dollars). Growth in LNG imports, Alaska production, and lower 48 production from nonconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand. The projected 2025 wellhead natural gas price in *AEO2005* is more than 30 cents per thousand cubic feet higher than the *AEO2004* projection, primarily as a result of lower assumed finding rates (reserve additions per well) for onshore resources.

Figure 1. Energy prices, 1970-2025 (2003 dollars per million Btu)



In *AEO2005*, the combination of more moderate increases in coal production, expected improvements in mine productivity, and a continuing shift to low-cost coal from the Powder River Basin in Wyoming leads to a gradual decline in the average minemouth price, to approximately $17.00 per ton shortly after 2010. The price is projected to remain nearly constant between 2010 and 2020 (Figure 1), increasing after 2020 as rising natural gas prices and the need for baseload generating capacity lead to the construction of many new coal-fired generating plants. By 2025, the average minemouth price is projected to be $18.26 per ton, which is higher than the *AEO2004* projection of $16.82 per ton. The *AEO2005* projection is equivalent to an average minemouth coal price of $31.25 per ton in nominal dollars in 2025.

Average delivered electricity prices are projected to decline from 7.4 cents per kilowatthour (2003 dollars) in 2003 to a low of 6.6 cents per kilowatthour in 2011 as a result of an increasingly competitive generation market and a decline in natural gas prices. After 2011, average real electricity prices are projected to increase (Figure 1), reaching 7.3 cents per kilowatthour in 2025 (equivalent to 12.5 cents per kilowatthour in nominal dollars). In *AEO2004*, real electricity prices followed a similar pattern but were projected to be slightly lower in 2025, at 7.0 cents per kilowatthour. The higher electricity price projection in *AEO2005* results primarily from higher expected fuel costs for coal- and natural-gas-fired electricity generation, particularly in the later years of the forecast.

Energy Consumption

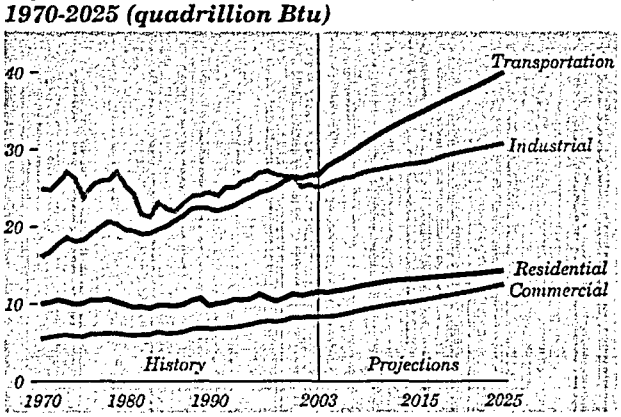
Total primary energy consumption in *AEO2005* is projected to increase from 98.2 quadrillion British thermal units (Btu) in 2003 to 133.2 quadrillion Btu in 2025 (an average annual increase of 1.4 percent). *AEO2004* projected energy consumption of 136.5 quadrillion Btu in 2025. Other than nuclear energy, the *AEO2005* projections for the consumption of all

energy sources in 2025 are lower than those in *AEO-2004*. Among the most important factors accounting for the differences are higher energy prices, lower projected growth rates in industrial production, specific updates in the chemical and pulp and paper industries, revisions to the capital cost of generating technologies, and revisions to transportation sector vehicle miles traveled.

Consistent with population growth rates and household formation, delivered residential energy consumption is projected to grow from 11.6 quadrillion Btu in 2003 to 14.3 quadrillion Btu in 2025 (Figure 2), at an average rate of 0.9 percent per year between 2003 and 2025 (1.3 percent per year between 2003 and 2010, slowing to 0.8 percent per year between 2010 and 2025). The most rapid growth in energy demand in *AEO2005* is projected to be for electricity used to power computers, electronic equipment, and appliances. *AEO2005* includes changes in the residential sector that have offsetting influences on the forecast of energy consumption, including more rapid growth in the total number of U.S. households; higher delivered prices for natural gas, electricity, and distillate fuel; and a better accounting of additions to existing homes and the height of ceilings in new homes.

Consistent with the projected increase in commercial floorspace, delivered commercial energy consumption is projected to grow at an average annual rate of 1.9 percent between 2003 and 2025 (Figure 2), reaching 12.5 quadrillion Btu in 2025 (slightly more than the 12.2 quadrillion Btu projected in *AEO2004*). The most rapid increase in energy demand is projected for electricity used for computers, office equipment, telecommunications, and miscellaneous small appliances. The higher forecast for commercial energy consumption in *AEO2005* results from a higher projected rate of growth in commercial floorspace, averaging 1.7 percent per year between 2003 and 2025, as compared with the projected average of 1.5 percent per year in *AEO2004*.

Figure 2. Delivered energy consumption by sector, 1970-2025 (quadrillion Btu)



Delivered industrial energy consumption in *AEO-2005* is projected to increase at an average rate of 1.0 percent per year between 2003 and 2025 (Figure 2), reaching 30.8 quadrillion Btu in 2025 (significantly lower than the *AEO2004* forecast of 33.4 quadrillion Btu). The *AEO2005* forecast includes slower projected growth in the dollar value of industrial product shipments relative to *AEO2004*, because of the slowdown in production growth in recent years and a reassessment of the prospects for growth in the chemical and pulp and paper industries.

Energy consumption in the transportation sector is projected to grow at an average annual rate of 1.8 percent between 2003 and 2025 in the *AEO2005* forecast (Figure 2), reaching 40.0 quadrillion Btu in 2025 (1.1 quadrillion Btu lower than the *AEO2004* projection). Two factors account for the reduction in projected transportation energy use from *AEO2004* to *AEO-2005*: first, expectations about light vehicle travel per capita have been reduced, based on new historical population and income data; and second, fuel economy data have been updated, resulting in a slightly improved average fuel economy for the light-duty vehicle stock over the forecast.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,657 billion kilowatthours in 2003 to 5,467 billion kilowatthours in 2025, increasing at an average rate of 1.8 percent per year. Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the end-use sectors is partially offset in the *AEO2005* forecast by improved efficiency in these and other, more traditional electrical applications and by slower growth in electricity demand in the industrial sector.

Total demand for natural gas is projected to increase at an average annual rate of 1.5 percent from 2003 to 2025 (Figure 3), primarily as a result of increasing use for electricity generation and industrial applications, which together account for about 75 percent of the projected growth in natural gas demand from 2003 to 2025. Total projected consumption of natural gas in 2025 is 0.7 trillion cubic feet lower in *AEO2005* than was projected in *AEO2004*. The growth in demand for natural gas slows in the later years of the forecast (0.9 percent per year from 2015 to 2025, compared with 2.1 percent per year from 2003 to 2010), as rising

natural gas prices lead to the construction of more coal-fired capacity for electricity generation.

In *AEO2005*, total coal consumption is projected to increase from 1,095 million short tons in 2003 to 1,508 million short tons in 2025—59 million short tons less than the *AEO2004* projection of 1,567 million short tons in 2025. From 2003 to 2025, coal consumption is projected to grow by 1.5 percent per year in the *AEO2005* forecast. The primary reason for the lower growth is an update of assumptions made about the relative capital costs of new coal- and natural-gas-fired power plants in the *AEO2005* forecast. In *AEO2005*, total coal consumption for electricity generation is projected to increase by an average of 1.6 percent per year, from 1,004 million short tons in 2003 to 1,425 million short tons in 2025, compared with the *AEO2004* projection of 1,477 million short tons in 2025.

Total petroleum demand is projected to grow at an average annual rate of 1.5 percent in the *AEO2005* forecast, from 20.0 million barrels per day in 2003 to 27.9 million barrels per day in 2025. In *AEO2005*, an increase of 0.3 million barrels per day in petroleum use for electricity generation in 2025, relative to the *AEO2004* projection, is more than offset by a reduction of 0.7 million barrels per day in total petroleum use in the industrial and transportation sectors in 2025—the result of projected higher energy prices, slower growth in industrial production, and improved average fuel economy for light-duty vehicles.

Total marketed renewable fuel consumption (including ethanol for gasoline blending, of which 0.2 quadrillion Btu is included with "petroleum products" consumption in Table 1), is projected to grow by 1.5 percent per year in *AEO2005*, from 6.1 quadrillion Btu in 2003 to 8.5 quadrillion Btu in 2025, as a result of State mandates for renewable electricity generation, higher natural gas prices, and the effect of production tax credits. About 60 percent of the projected demand for renewables in 2025 is for grid-related electricity generation (including combined heat and power), and the rest is for dispersed heating and cooling, industrial uses, and fuel blending. Despite higher fossil fuel prices, the projected demand for renewables in 2025 in *AEO2005* is 0.9 quadrillion Btu less than in *AEO2004*. Renewable generating technologies are not as competitive in *AEO2005*, because the costs for natural gas technologies are lower, wind technology costs are about 10 percent higher, and several geothermal projects that were assumed to be completed in the *AEO2004* forecast are not included in *AEO2005*.

Energy Intensity

Energy intensity, as measured by energy use per 2000 dollar of GDP, is projected to decline at an average annual rate of 1.6 percent in the *AEO2005* forecast, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 4). The rate of decline is faster in *AEO2005* than the projected rate of 1.4 percent per year in *AEO2004*, because higher energy prices in the *AEO-2005* forecast are projected to result in generally lower energy consumption and a more rapid shift of energy use away from industrial uses to energy services. The projected rate of decline in *AEO2005* falls between the historical averages of 2.3 percent per year from 1970 to 1986, when energy prices increased in real terms, and 0.7 percent per year from 1986 to 1992, when energy prices were generally falling.

Since 1992, energy intensity has declined on average by 1.9 percent per year. During this period, the role of energy-intensive industries in the U.S. economy has fallen sharply. The share of industrial output from the energy-intensive industries declined on average

Figure 3. Energy consumption by fuel, 1970-2025 (quadrillion Btu)

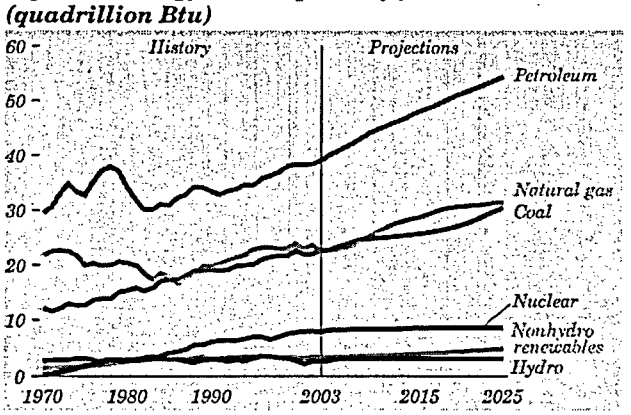
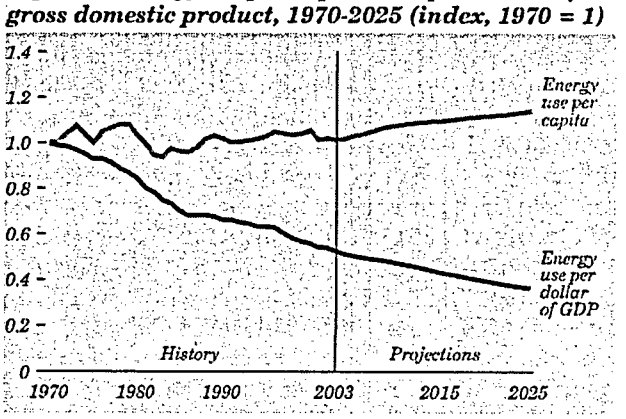


Figure 4. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)



by 1.3 percent per year from 1992 to 2003. In the *AEO2005* forecast, the energy-intensive industries' share of total industrial output is projected to continue declining but at a slower rate of 0.8 percent per year, which leads to the projected slower annual rate of reduction in energy intensity.

Historically, energy use per person has varied over time with the level of economic growth, weather conditions, and energy prices, among many other factors. During the late 1970s and early 1980s, energy consumption per capita fell in response to high energy prices and weak economic growth. Starting in the late 1980s and lasting through the mid-1990s, energy consumption per capita increased with declining energy prices and strong economic growth. Per capita energy use is projected to increase in *AEO2005*, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use increases by an average of 0.5 percent per year between 2003 and 2025 in *AEO2005*, slightly less than was projected in *AEO2004* (0.7 percent per year), as a result of the higher energy prices in *AEO2005*.

The potential for more energy conservation has received increased attention recently as energy prices have risen. Although energy conservation is projected to be induced through energy price increases, *AEO2005* does not assume policy-induced conservation measures beyond those in existing legislation and regulation, nor does it assume behavioral changes beyond those experienced in the past.

Electricity Generation

In *AEO2005*, the projected average price for natural gas delivered to electricity generators is 45 cents per million Btu higher in 2025 than was projected in *AEO2004*; however, the impact of the higher prices is offset by the assumption that capital costs for new natural-gas-fired power plants will be lower than assumed in *AEO2004*, as well as the inclusion of more recently completed and announced plans for gas-fired power plants. As a result, in *AEO2005*, projected cumulative capacity additions and generation from natural-gas-fired power plants are higher than in *AEO2004*, and capacity additions and generation from coal-fired power plants are lower. The *AEO2005* projection of 1,406 billion kilowatthours of electricity generation from natural gas in 2025 is 8 percent higher than in *AEO2004* (1,304 billion kilowatthours) and more than twice the 2003 level of about 630 billion kilowatthours (Figure 5). Less new gas-fired capacity is added in the later years of the forecast because of the projected rise in natural gas prices.

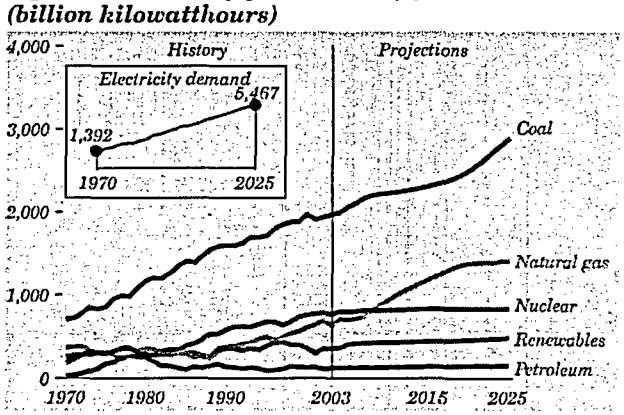
The natural gas share of electricity generation (including generation in the end-use sectors) is projected to increase from 16 percent in 2003 to 24 percent in 2025. The share from coal is projected to decrease from 51 percent in 2003 to 50 percent in 2025. *AEO2005* projects that 87 gigawatts of new coal-fired generating capacity will be constructed between 2004 and 2025 (compared with 112 gigawatts in *AEO2004*).

Nuclear generating capacity in *AEO2005* is projected to increase from 99.2 gigawatts in 2003 to 102.7 gigawatts in 2025—about the same as in *AEO2004*—as a result of uprates of existing plants between 2003 and 2025. All existing nuclear plants are projected to continue to operate, but new plants are not expected to be economical. Total nuclear generation is projected to grow from 764 billion kilowatthours in 2003 to 830 billion kilowatthours in 2025 in *AEO2005*.

The use of renewable technologies for electricity generation is projected to grow slowly, both because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive technologies. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the forecast. *AEO2005* also includes the extension of the production tax credit for wind and biomass through December 31, 2005, as enacted in H.R. 1308, the Working Families Tax Relief Act of 2004. *AEO2004* assumed that the production tax credit would end on December 31, 2003, its statutory expiration date at the time *AEO2004* was prepared.

Total renewable generation in *AEO2005*, including combined heat and power generation, is projected to grow from 359 billion kilowatthours in 2003 to 489 billion kilowatthours in 2025, increasing by 1.4 percent per year.

Figure 5. Electricity generation by fuel, 1970-2025 (billion kilowatthours)



Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy supply through 2025. As a result, net imports of energy are projected to meet a growing share of energy demand (Figure 6). Net imports are expected to constitute 38 percent of total U.S. energy consumption in 2025, up from 27 percent in 2003.

Projected U.S. crude oil production increases from 5.7 million barrels per day in 2003 to a peak of 6.2 million barrels per day in 2009 as a result of increased production offshore, predominantly from the deep waters of the Gulf of Mexico. Beginning in 2010, U.S. crude oil production begins to decline, falling to 4.7 million barrels per day in 2025.

Total domestic petroleum supply (crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs) follows the same pattern as crude oil production in the *AEO2005* forecast, increasing from 9.1 million barrels per day in 2003 to a peak of 9.8 million barrels per day in 2009, then declining to 8.8 million barrels per day in 2025 (Figure 7).

In 2025, net petroleum imports, including both crude oil and refined products, are expected to account for 68 percent of demand (on the basis of barrels per day), up from 56 percent in 2003. Despite an expected increase in distillation capacity at domestic refineries, net imports of refined petroleum products account for a growing portion of total net imports, increasing from 14 percent in 2003 to 16 percent in 2025 (as compared with 20 percent in *AEO2004*).

The most significant change in the *AEO2005* energy supply projections is in the outlook for natural gas, particularly domestic lower 48 onshore production and LNG imports. Domestic natural gas production increases from 19.1 trillion cubic feet in 2003 to 21.8 trillion cubic feet in 2025 in the *AEO2005* forecast; *AEO2004* projected 24.0 trillion cubic feet of domestic natural gas production in 2025.

The projection for conventional onshore production of natural gas is lower in *AEO2005* than it was in *AEO2004*, because of slower reserve growth, fewer new discoveries, and higher exploration and development costs. Lower 48 onshore natural gas production is projected to increase from 13.9 trillion cubic feet in 2003 to a peak of 15.7 trillion cubic feet in 2012 before falling to 14.7 trillion cubic feet in 2025. In *AEO2004*, lower 48 onshore production reached 16.3 trillion cubic feet in 2025.

Offshore natural gas production in 2025 is also somewhat lower in *AEO2005* than it was in the *AEO2004* forecast. Lower 48 offshore production, which was 4.7 trillion cubic feet in 2003, is projected to increase in the near term (to 5.3 trillion cubic feet by 2014) because of the expected development of some large deepwater fields, including Mad Dog, Entrada, and Thunder Horse. After 2014, offshore production is projected to decline to 4.9 trillion cubic feet in 2025.

Although the projection for net U.S. imports of natural gas from Canada in 2025 in *AEO2005* is about the same as in *AEO2004*, the pattern of growth is very different in *AEO2005*. *AEO2004* projected that the 2002 level of net Canadian imports (3.6 trillion cubic feet) could be sustained through 2012 before falling off. *AEO2005* expects net Canadian imports to decline from 2003 levels of 3.1 trillion cubic feet to about 2.5 trillion cubic feet in 2009, followed by an increase after 2010 to 3.0 trillion cubic feet in 2015 as a result of rising natural gas prices, the introduction of gas from the Mackenzie Delta, and increased production of coalbed methane. After 2015, because of reserve depletion effects and growing domestic demand in Canada, net U.S. imports are projected to decline to 2.6 trillion cubic feet in 2025. The *AEO2005* forecast reflects revised expectations about Canadian natural

Figure 6. Total energy production and consumption, 1970-2025 (quadrillion Btu)

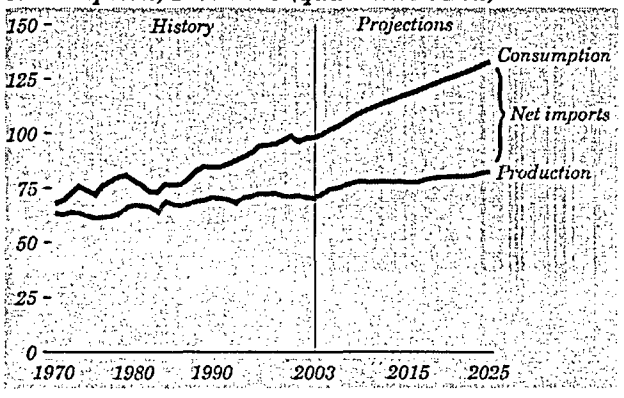
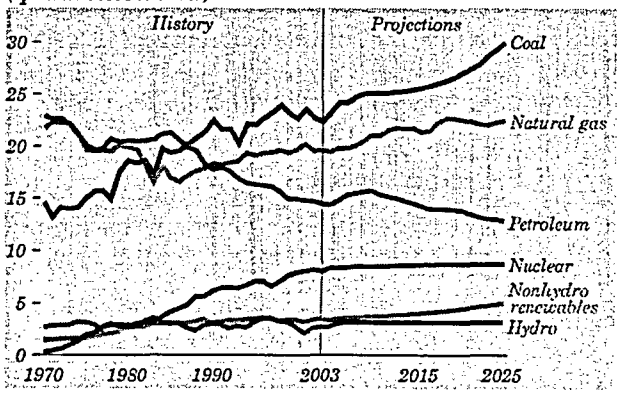


Figure 7. Energy production by fuel, 1970-2025 (quadrillion Btu)



gas production, particularly coalbed methane and conventional production in Alberta, based in part on data and projections from Canada's National Energy Board and other sources.

Growth in U.S. natural gas supplies will depend on unconventional domestic production, natural gas from Alaska, and imports of LNG. Total nonassociated unconventional natural gas production is projected to grow from 6.6 trillion cubic feet in 2003 to 8.6 trillion cubic feet in 2025. With completion of an Alaskan natural gas pipeline in 2016, Alaska's total production is projected to increase from 0.4 trillion cubic feet in 2003 to 2.2 trillion cubic feet in 2025. With the exception of the facility at Everett, Massachusetts, three of the four existing U.S. LNG terminals (Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) are expected to expand by 2007; and additional facilities are expected to be built in New England and elsewhere in the lower 48 States, serving the Gulf, Mid-Atlantic, and South Atlantic States, including a new facility in the Bahamas serving Florida via a pipeline. Another facility is projected to be built in Baja California, Mexico, serving a portion of the California market. Total net LNG imports to the United States and the Bahamas are projected to increase from 0.4 trillion cubic feet in 2003 to 6.4 trillion cubic feet in 2025, about one-third more than the *AEO2004* projection of 4.8 trillion cubic feet.

As domestic coal demand grows in *AEO2005*, U.S. coal production is projected to increase at an average rate of 1.5 percent per year, from 1,083 million short tons in 2003 to 1,488 million short tons in 2025. The *AEO2005* projection for coal production in 2025 is 55 million short tons less than in *AEO2004* because of revisions in the relative capital costs and efficiencies for new coal- and natural-gas-fired generating capacity in *AEO2005*, which lead to a lower projected level of coal demand than was projected in *AEO2004*, despite higher natural gas prices in *AEO2005*. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental coal production. In 2025, nearly two-thirds of coal production is projected to originate from the western States.

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase from 5,789 million metric tons in 2003 to 8,062 million metric tons in 2025 in *AEO2005*, an average annual increase of 1.5 percent (Figure 8). The carbon dioxide emissions intensity of the U.S. economy is projected to fall from 558 metric tons per million dollars of GDP in 2003 to 397 metric tons per million dollars in 2025—an average decline of 1.5 percent per year. In comparison, *AEO2004* projected a 1.4-percent average annual decline in emissions intensity and 8,142 million metric tons of carbon dioxide emissions in 2025.

By sector, projected carbon dioxide emissions from the residential, commercial, and electric power sectors in 2025 are higher in *AEO2005* than they were in *AEO2004* because of higher projected energy consumption in each of those sectors (particularly, electricity consumption in the residential and commercial sectors and natural gas and petroleum consumption for electricity generation in the electric power sector), whereas *AEO2005* projects lower energy consumption in the industrial and transportation sectors in 2025 and lower carbon dioxide emissions in both sectors than were projected in *AEO2004*. In the electric power sector, the higher *AEO2005* projections for carbon dioxide emissions from natural gas and petroleum use for generation more than offset the lower projection for emissions from coal-fired generation. In total, however, the lower levels of carbon dioxide emissions projected for the industrial and transportation sectors in 2025 outweigh the higher levels projected for the other energy-consuming sectors, so that total emissions in 2025 are lower in the *AEO2005* forecast than they were in *AEO2004*. The *AEO* projections do not include future policy actions or agreements that might be taken to reduce carbon dioxide emissions.

Figure 8. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2025 (million metric tons)

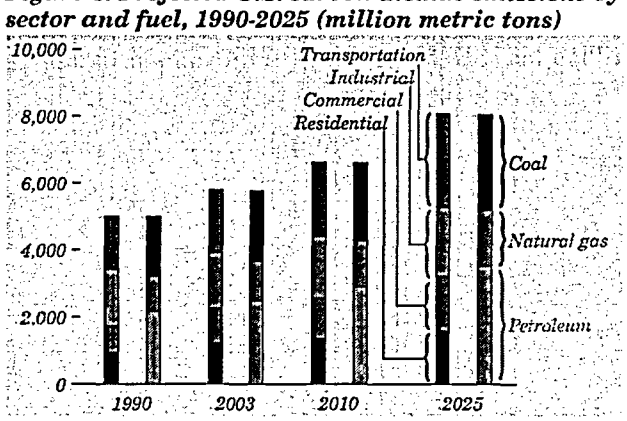


Table 1. Total energy supply and disposition in the *AEO2005* reference case: summary, 2002-2025

Energy and economic factors	2002	2003	2010	2015	2020	2025	Average annual change, 2003-2025
Primary energy production (quadrillion Btu)							
Petroleum	14.71	14.38	15.41	14.31	13.83	12.82	-0.5%
Dry natural gas	19.48	19.58	20.97	21.33	22.48	22.42	0.6%
Coal	22.70	22.66	25.10	25.56	27.04	29.90	1.3%
Nuclear power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable energy	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other	1.12	0.93	0.97	0.78	0.77	0.82	-0.5%
Total	**71.94**	**71.42**	**77.79**	**77.73**	**80.35**	**82.73**	**0.7%**
Net imports (quadrillion Btu)							
Petroleum	22.64	24.10	28.61	33.10	36.87	41.11	2.5%
Natural gas	3.59	3.32	5.06	7.19	8.08	8.87	4.6%
Coal/other (- indicates export)	-0.47	-0.43	-0.14	0.19	0.25	0.58	NA
Total	**25.75**	**26.99**	**33.53**	**40.47**	**45.21**	**50.55**	**2.9%**
Consumption (quadrillion Btu)							
Petroleum products	38.41	39.09	44.84	48.07	51.30	54.42	1.5%
Natural gas	23.59	22.54	26.11	28.69	30.73	31.47	1.5%
Coal	21.98	22.71	24.95	25.71	27.27	30.48	1.3%
Nuclear power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable energy	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Petroleum (million barrels per day)							
Domestic crude production	5.74	5.68	6.02	5.49	5.21	4.73	-0.8%
Other domestic production	3.60	3.38	3.59	3.77	4.00	4.10	0.9%
Net imports	10.54	11.24	13.37	15.40	17.11	19.11	2.4%
Consumption	19.71	20.00	22.98	24.67	26.32	27.93	1.5%
Natural gas (trillion cubic feet)							
Production	19.03	19.13	20.49	20.85	21.97	21.91	0.6%
Net imports	3.50	3.24	4.94	7.02	7.89	8.66	4.6%
Consumption	22.98	21.95	25.44	27.96	29.95	30.67	1.5%
Coal (million short tons)							
Production	1,105	1,083	1,238	1,270	1,345	1,488	1.5%
Net imports	-23	-18	-9	3	7	20	NA
Consumption	1,066	1,095	1,229	1,273	1,352	1,508	1.5%
Prices (2003 dollars)							
World oil price (dollars per barrel)	24.10	27.73	25.00	26.75	28.50	30.31	0.4%
Domestic natural gas at wellhead (dollars per thousand cubic feet)	3.06	4.98	3.64	4.16	4.53	4.79	-0.2%
Domestic coal at minemouth (dollars per short ton)	18.23	17.93	17.30	16.89	17.25	18.26	0.1%
Average electricity price (cents per kilowatthour)	7.4	7.4	6.6	6.9	7.2	7.3	-0.1%
Economic indicators							
Real gross domestic product (billion 2000 dollars)	10,075	10,381	13,084	15,216	17,634	20,292	3.1%
GDP chain-type price index (index, 2000=1.000)	1.041	1.060	1.218	1.373	1.563	1.814	2.5%
Real disposable personal income (billion 2000 dollars)	7,560	7,734	9,594	11,192	12,783	14,990	3.1%
Value of manufacturing shipments (billion 1996 dollars)	5,067	5,105	6,165	6,850	7,633	8,469	2.3%
Energy intensity (thousand Btu per 2000 dollar of GDP)	**9.73**	**9.47**	**8.51**	**7.78**	**7.13**	**6.57**	**-1.6%**
Carbon dioxide emissions (million metric tons)	**5,751**	**5,789**	**6,627**	**7,052**	**7,520**	**8,062**	**1.5%**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.
Source: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by the EIA are required to be policy-neutral, the projections in this *AEO2005* generally are based on Federal and State laws and regulations in effect on or before October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections.

Examples of Federal and State legislation incorporated in the projections include the following:

- The National Appliance Energy Conservation Act of 1987
- The Clean Air Act Amendments of 1990 (CAAA90), which include new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The Energy Policy Act of 1992 (EPACT)
- The Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels
- The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- The American Jobs Creation Act of 2004, which includes incentives and tax credits for biodiesel fuels, a modified depreciation schedule for the Alaska natural gas pipeline, and an expansion of the 1.8-cent renewable energy production tax credit (PTC) to include geothermal and solar generation technologies
- The Military Construction Appropriations Act of 2005, which includes provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction
- The Working Families Tax Relief Act of 2004, which includes an extension of the 1.8-cent PTC for wind and closed-loop biomass to December 31, 2005; tax deductions for qualified clean-fuel and electric vehicles; and changes in the rules governing oil and gas well depletion
- State of Alaska's Right-Of-Way Leasing Act Amendments of 2001, which prohibit leases across State land for a "northern" or "over-the-top" natural gas pipeline route running east from the North Slope to Canada's MacKenzie River Valley
- State renewable portfolio standards, including the California renewable portfolio standards passed on September 12, 2002
- State programs for restructuring of the electricity industry.

AEO2005 assumes that State taxes on gasoline, diesel, jet fuel, and E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) will increase with inflation, and that Federal taxes on those fuels will continue at 2003 levels in nominal terms. *AEO2005* also assumes the continuation of the ethanol tax incentive through 2025. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2005* assumes their continuation throughout the forecast.

Examples of Federal and State regulations incorporated in *AEO2005* include the following:

- Standards for energy-consuming equipment that have been announced, including the 13 seasonal energy efficiency ratio (SEER) [2] for new central air conditioners and heat pumps that were recently reestablished by the U.S. Court of Appeals after originally being set in January 2001
- The new corporate average fuel economy (CAFE) standards for light trucks published by the National Highway Traffic Safety Administration (NHTSA) in 2003
- Federal Energy Regulatory Commission (FERC), Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets
- The December 2002 Hackberry Decision, which terminated open access requirements for new onshore LNG terminals
- The new boiler limits established by the U.S. Environmental Protection Agency (EPA) on February 26, 2004, which limit emissions of hazardous air pollutants from industrial, commercial, and institutional boilers and process heaters by requiring that they comply with a Maximum Achievable Control Technology (MACT) floor.

AEO2005 includes the CAAA90 requirement of a phased-in reduction in vehicle emissions of regulated pollutants. In addition, *AEO2005* incorporates the CAAA90 requirement of a phased-in reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. *AEO2005* also incorporates nitrogen oxide (NO_x) boiler standards issued by the EPA under CAAA90. The 19-State NO_x cap and trade program in the Northeast and Midwest is also represented. Limits on emissions of mercury, which have not yet been promulgated, are not represented.

AEO2005 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000 under CAAA90. The Tier 2 standards for reformulated gasoline (RFG) were required by 2004 but will not be fully realized in conventional gasoline until 2008 due to allowances for small refineries. *AEO2005* also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized by the EPA in December 2000, which requires the production of at least 80 percent ULSD (15 parts sulfur per million) highway diesel between June 2006 and June 2010 and a 100-percent requirement for ULSD thereafter (see Appendix F for more details). It also includes the new rules for nonroad diesel issued by the EPA on May 11, 2004, regulating nonroad diesel engine emissions and sulfur content in fuel. The *AEO2005* projections reflect legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in 17 States and assumes that the Federal oxygen requirement for RFG in Federal nonattainment areas will remain intact.

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive Federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The *AEO2005* projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided.

More detailed information on recent legislative and regulatory developments is provided below.

13 SEER Standard for Central Air Conditioners and Heat Pumps

In January 2004, after years of litigation in a case that pitted environmental groups and Attorneys General from 10 States against the U.S. Secretary of Energy, the U.S. Court of Appeals for the Second Circuit reestablished the central air conditioner and heat pump standard originally set in January 2001 [*3*]. The Court's ruling, which struck down a May 2002 rollback of the 2001 standard to a 12 SEER, mandates that all new central air conditioners and heat pumps meet a 13 SEER standard by January 2006, requiring a 30-percent increase in efficiency relative to current law. The *AEO2005* reference case incorporates the 13 SEER standard as mandated by the Court's ruling.

In order to gauge the impact of the new standard on electricity consumption, consumer expenditures, and carbon dioxide emissions, a sensitivity case assuming a continuation of the previous 12 SEER standard was modeled. Table 2 shows the impacts of the 13 SEER standard assumed in the reference case, as compared with the 12 SEER standard assumed in the sensitivity case. As expected, the projections for electricity consumption and expenditures are lower in the reference case than in the 12 SEER case; however, the savings come at an additional cost to consumers. Through 2015 the additional costs of new equipment outweigh savings, resulting in a negative net present value for the 13 SEER standard (assuming a 7-percent real discount rate). In the long run, however, additional years of savings per unit provide a positive ($3.6 billion) net present value, meaning that the standard, on average, provides economic benefits to consumers in the form of reduced energy expenditures.

Table 2. Impacts of 13 SEER central air conditioner and heat pump standard compared with 12 SEER standard, 2006-2025

			Cumulative	
Projection	*2015*	*2025*	*2006-2015*	*2006-2025*
Electricity consumption savings (billion kilowatthours)	*11.1*	*16.6*	*59.6*	*211.7*
Energy bill savings (billion 2004 dollars)	*0.8*	*0.7*	*5.7*	*12.6*
Equipment cost increase (billion 2004 dollars)	*0.5*	*0.2*	*5.8*	*8.9*
Net present value (billion 2004 dollars)	—	—	*-0.1*	*3.6*
Increase in air conditioner stock efficiency (percent)	*5.6*	*6.8*	—	—
Carbon dioxide emissions reduction (million metric tons)	*1.1*	*-3.6*	*7.8*	*1.0*

The difference between projected carbon dioxide emissions in the two cases depends on the fuel mix associated with the electricity generation. In the near term, the reduction in electricity demand in the reference case is not large enough to change the pattern of capacity additions or fuel mix, and lower electricity demand causes a decrease in carbon dioxide emissions both in 2015 and cumulatively from 2006 to 2015 (Table 2). In later years, the amount of peak demand relative to baseload demand is lower in the reference case, and more coal-fired capacity is added at the expense of natural gas capacity. The change in fuel mix causes carbon dioxide emissions to increase, despite slightly lower levels of electricity demand. Emissions in 2025 are 3.6 million metric tons (0.2 percent) higher in the reference case, but cumulative emissions from 2003 through 2025 are 1.0 million metric ton lower than in the 12 SEER case (1 metric ton is equal to 1,000 kilograms).

Maximum Achievable Control Technology for New Industrial Boilers

As part of CAAA90, the EPA on February 26, 2004, issued a final rule—the National Emission Standards for Hazardous Air Pollutants (NESHAP)—to reduce emissions of hazardous air pollutants (HAPs) from industrial, commercial, and institutional boilers and process heaters [*4*]. The rule requires industrial boilers and process heaters to meet limits on HAP emissions to comply with a MACT "floor level" of control that is the minimum level such sources must meet to comply with the rule. The major HAPs to be reduced are hydrochloric acid, hydrofluoric acid, arsenic, beryllium, cadmium, and nickel. The EPA predicts that the boiler MACT rule will reduce those HAP emissions from existing sources by about 59,000 tons per year in 2005 [*5*].

The MACT standards apply to major sources of HAPs, or units that emit or have the potential to emit a single HAP at 10 tons or more per year or a combination of HAPs at 25 tons or more per year. The EPA estimates that 58,000 existing boilers and process heaters and 800 new boilers and process heaters built each year over the next 5 years will be subject to the rule. Existing boilers and process heaters must comply with the rule no later than 3 years after it is published in the *Federal Register*. In addition, the owners of existing units may petition for an extra year to comply. New boilers and process heaters must comply when they are brought on line. The final rule provides flexibility in compliance through averaging of emissions from multiple units on a single site and lowering of emissions by altering work practices, installing control devices, or physically removing toxics. Fuel switching is not an available option to meet the MACT floor level, because it may increase emissions of some HAPs while reducing the emissions of others.

The industries most affected by the rule will be furniture, paper, lumber, and electrical services, which together account for nearly 60 percent of the affected units. The EPA estimates the total nationwide capital costs for the final rule to be $1.4 billion to $1.7 billion over the first 5 years, with annualized costs between $690 million and $800 million.

New boilers are expected to meet the standards in the absence of the rule, and retrofit costs are anticipated to be relatively small in aggregate. Consequently, inclusion of the rule does not materially affect the *AEO2005* projection for the industrial sector.

Clean Air Nonroad Diesel Rule

On June 29, 2004, the EPA issued a comprehensive final rule regulating emissions from nonroad diesel engines and sulfur content in nonroad diesel fuel [*6*]. The nonroad fuel market makes up more than 18 percent of the total distillate pool. The rule applies to new equipment covering a broad range of engine sizes, power ratings, and equipment types. There are currently about 6 million pieces of nonroad equipment operating in the United States, and more than 650,000 new units are sold each year.

The rulemaking covers such equipment as tractors, bulldozers, graders, backhoes, heavy construction, mining, and logging equipment, airport tugs, locomotives, and commercial marine vessels. The regulations represent a tiered emissions reduction approach based on engine horsepower, with phased-in restrictions on emissions of particulate matter (PM), NO_x, and nonmethane hydrocarbons. The rule reduces diesel engine emissions by more than 90 percent and fuel sulfur content by 99 percent from current levels.

The regulation addresses emissions and fuels simultaneously to maximize emission reductions by integrating engine and fuel controls as a system. To meet the standards, engine manufacturers will be required to produce new engines with advanced emission control technologies similar to those already expected for on-road (highway) heavy trucks and buses. Refiners will be supplying new lower sulfur diesel fuels in both cases.

Emission Standards

By 2014, the new Tier 4 regulations will require nonroad diesel engines to cut emissions of pollutants by

more than 90 percent [7]. Standards for new engines will be phased in starting with the smallest engines in 2008 until all but the very largest diesel engines meet both NO_x and PM standards in 2014 (Table 3). Some of the largest engines (750-plus horsepower) will have one additional year to meet the emissions standards.

The final rule includes flexibility provisions aimed at helping small engine manufacturers meet the requirements. The EPA Tier 4 standards do not require retrofitting older diesel engines currently in service and do not apply to diesel engines used in locomotives and marine vessels, but they do cover fuel requirements for those equipment categories.

In a separate action, the EPA took the first step toward proposing new emissions standards for diesel engines by issuing an Advanced Notice of Proposed Rulemaking on June 29, 2004 [8]. Contemplated standards would apply to marine diesels used in all new commercial, recreational, and auxiliary marine diesel engines except for very large engines used for propulsion of deep-sea vessels. For locomotives, both new and existing diesel units would require advanced emission control technologies similar to those for heavy-duty trucks and buses. The widespread availability of clean nonroad diesel fuel required under the new fuel standards will enable the use of advanced control technology on locomotive and marine engines.

The EPA estimates that anticipated compliance costs will vary with the size and complexity of equipment, in the range of 1 to 3 percent of total purchase price for most categories of nonroad diesel equipment [9]. The new nonroad diesel emission standards, when fully implemented, are expected to provide significant public health benefits.

Fuel Standards

The final rule, to be implemented in multiple steps, requires sulfur content for all nonroad locomotive and marine (NRLM) diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting in mid-2007. It also establishes a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the action establishes a ULSD limit of 15 ppm in mid-2012, providing the refining industry flexibility to align fuel supply operations with all other on-road and nonroad ULSD fuel regulations, which take effect in mid-2010. After refiners, the new standards will apply to terminals, wholesalers, retailers, and end users in subsequent months as production flows through the distribution chain.

The nonroad diesel requirements have implications for the refining industry and, especially, for small refiners (defined as having less than 155,000 barrels per day of crude oil charge capacity and less than 1,500 corporate employees). Approximately 20 refiners fall into the small refiner category. They are dispersed across the country, with the largest concentration located in the Rocky Mountain Region. Small refiners are granted three additional years to meet the 500 ppm standard for NRLM diesel, starting in mid-2007 (Table 4). The challenges facing small refiners include additional time needed to secure capital funding, a need for longer leadtimes because of limited engineering expertise, and limits on the availability of contractors, who will be performing upgrades for major refiners.

Table 3. Final nonroad diesel emissions standards

Rated engine power	First year of standards or phase-in period	Particulate matter (grams per horsepower per hour)	Nitrogen oxides (grams per horsepower per hour)
Less than 25 horsepower	2008	0.30	—
25 to less than 75 horsepower	2013	0.02	3.5
75 to less than 175 horsepower	2012-2013	0.01	0.30
175 to less than 750 horsepower	2011-2013	0.01	0.30
750 horsepower or more	2011-2014	0.075	2.6 and 0.50
	2015	0.02 and 0.03	0.50

Note: Where a range of years is provided, 40 CFR 1039.102 prescribes a gradual phase-in whereby a cumulative percentage of total engines for a manufacturer must comply each year prior to the final year.

Table 4. Timeline for implementing nonroad diesel fuel sulfur limits

Fuel type and refiners	Mid-2007	Mid-2010	Mid-2012	Mid-2014 and after
Nonroad diesel				
Refiners other than small	500 ppm	15 ppm	15 ppm	15 ppm
Small refiners	—	500 ppm	15 ppm	15 ppm
Locomotive and marine diesel				
Refiners other than small	500 ppm	500 ppm	15 ppm	15 ppm
Small refiners	—	500 ppm	500 ppm	15 ppm

For early or overcompliance with the fuel sulfur standards, a regional averaging, banking, and trading program will be created; however, credits may not be used or traded for use outside the credit trading region in which they are generated [*10*]. For the 500 ppm standard beginning in mid-2007, small refiners outside the Northeast/Mid-Atlantic area can use credits to continue producing high-sulfur nonroad fuel until the credits expire in mid-2010. After mid-2014, small refiners must comply with the 15 ppm standard for NRLM diesel.

The rule recognizes certain exceptions. For Alaska, NRLM diesel covers only areas served by Federal highways. Rural and remote areas are not required to convert to ULSD until 2011. For stationary power sources, the rule excludes No. 4, 5, and 6 heavy distillates. In special marine situations, giant Category 3 ocean ship engines face a separate regulation expected by April 2007. Category 2 or 3 marine diesel engines using distillate with a distillation point over 700°F are excluded.

There are also special exceptions for transmix facilities on pipelines [*11*]. Because transmix facilities do not have sulfur removal equipment to clean up pipeline interface mixes, the final rule provides that they may produce fuels for sale into the NRLM markets that meet small refiner provisions, in order to avoid the burden of additional investment in treating equipment or returning mix to refineries for reprocessing. After the NRLM small refiner provisions expire in 2014, transmix processors may continue to sell 500 ppm fuel into the locomotive and marine market.

The rule also prescribes certain dyeing, tracking, and record keeping requirements to ensure that fuel is not diverted from authorized channels and that taxes are properly paid. The Internal Revenue Service ordinarily requires that fuel used in NRLM engines be dyed before leaving the terminal, to indicate its nontaxed status. Fuels that meet on-road diesel specifications but are destined for NRLM markets can leave the terminal undyed, provided that the tax is paid first. NRLM users can then apply for a tax refund. To minimize misfueling, a system of labels is prescribed on diesel retail pumps, fuel tank inlets, and dashboard and instrument panels, corresponding with the introduction of new diesel engines and equipment.

The EPA did not specify lubricity standards in the rule, because the industry has been working to finalize a universal standard for all diesel fuel. If the American Society for Testing and Materials does not establish a universal lubricity standard, a separate rulemaking applying to lubricity additives will be issued by the EPA.

Impacts of the Emission and Fuel Standards

The effects of the new NRLM diesel standards are represented in *AEO2005*. The National Energy Modeling System (NEMS) has been revised to reflect the nonroad rule and recalibrated for market shares of highway, NRLM diesel, and other distillate (mostly heating oil and excluding jet fuel and kerosene). The nonroad rule, following closely on the heels of the highway diesel rule, represents an incremental tightening of the entire diesel pool that will cause demand for high-sulfur distillate to diminish over time while demand for ULSD (both highway and NRLM) increases.

After 2007, during the rule's implementation, the projections for refinery distillate production are slightly lower with the rule in place because of the more stringent and costly processing requirements, and imports of distillate are higher. For the composite distillate market, prices are slightly higher with the rule in place and vary by sector. Table 5 shows key projections for distillate fuel prices, production, and imports in the *AEO2005* reference case, which includes the new nonroad diesel rule, and in a sensitivity case that does not include the new rule.

Because heating oil is not subject to NRLM diesel rules, residential distillate prices are not expected to be affected significantly. Eventually, however, residential prices are projected to parallel those in other sectors as the distillate market converges toward a universal ULSD standard. More than two-thirds of all high-sulfur distillate use after 2010 is projected to be concentrated in the Northeast.

In the commercial and industrial sectors, distillate fuel prices after 2010 are projected to be higher with the rule in place. Nonroad diesel is a relatively small portion of commercial distillate use, but it dominates industrial use. Thus, the price impact is greater for the industrial sector. For the electric power sector there is little or no projected impact on distillate prices. Diesel prices in the transportation sector are projected to be about 2 cents per gallon higher in 2010-2012 because of the nonroad diesel sulfur reduction and about 3 cents per gallon higher in 2014, when the sulfur content of all NRLM diesel fuel is reduced to 15 ppm.

EPA estimates [*12*] place the added cost of ULSD for NRLM diesel use in the range of about 7 cents per gallon; however, the EPA expects the added cost to be offset by reduced engine maintenance expenses, lowering the net incremental impact to about 4 cents per gallon. The EPA estimates assume complete turnover of nonroad diesel engines by 2030.

American Jobs Creation Act of 2004

The American Jobs Creation Act of 2004 [*13*] was signed into law on October 22, 2004. Most of the 650 pages of the Act are related to tax legislation. Provisions pertaining to energy are described below.

Diesel Excise Taxes

Section 241 phases out an excise fuel tax of 4.3 cents per gallon on railroads and inland waterway transportation incrementally between January 1, 2005, and January 1, 2007. Under current law, diesel fuel used in trains and fuels used in barges on certain inland waterways are subject to an excise tax of 4.4 cents per gallon. Revenues from 4.3 cents of the tax are retained in the General Fund. The remaining 0.1 cent is put in the Leaking Underground Storage Tank Fund, which is scheduled to expire on March 31, 2005. *AEO2005* reflects the phaseout of these excise taxes.

Ethanol Tax Credits

Section 301 establishes the Volumetric Ethanol Excise Tax Credit (VEETC). Before this Act, gasoline blenders could choose between an income tax credit of 51 cents per gallon of ethanol blended or a reduced rate of Federal excise tax on each gallon of gasoline blended with ethanol. Thus, gasoline containing 10 percent ethanol would be taxed at 13.2 cents per gallon instead of the usual 18.3 cents per gallon in calendar year 2005. Gasoline blended with 5.7 percent or 7.7 percent ethanol would receive a proportionally smaller reduction in the excise tax. The VEETC is instead assessed at a rate of 51 cents per gallon of ethanol, and the entire excise tax is assessed on the finished gasoline. This gives several advantages over the existing structure. VEETC applies to any blend of ethanol and gasoline. It also applies to ethyl tertiary butyl ether (ETBE), a gasoline blending component made from ethanol. The excise tax exemption does not apply to blends containing less than 5.7 percent or more than 10 percent ethanol, such as E85. The income tax credit can be taken for ethanol used in such blends or to make ETBE, but not all gasoline blenders have sufficient Federal income tax liability to take the credit. The VEETC is effective through 2010; the excise tax reduction will expire in 2007. This section also extends the alcohol income tax credit through 2010. *AEO2005* includes these tax credits and, in addition, assumes that they will remain in force indefinitely, given that historically they have been extended when they expired.

Biodiesel Tax Credits

The VEETC also applies to biodiesel blends. A diesel fuel blender can claim a credit of $1 per gallon of biodiesel made from agricultural commodities such as soybean oil and can claim a credit of 50 cents per gallon of biodiesel made from recycled oil such as yellow grease. Section 302 extends income tax credits for biodiesel blending similar to the alcohol income tax credits. The VEETC provision for biodiesel and the biodiesel income tax credits expire after 2006. Section 302 is modeled in the *AEO2005* reference case.

Rural Electric Cooperatives Income Treatment

Current law gives tax-exempt status for rural electric cooperatives if at least 85 percent of the cooperative's income comes from amounts collected from members for the sole purpose of meeting losses and expenses

Table 5. Key projections for distillate fuel markets in two cases, 2007-2014

		Projections							
		2007		2010		2012		2014	
Supply and prices	*2003*	*Reference case*	*No NRLM rule case*	*Reference case*	*No NRLM rule case*	*Reference case*	*No NRLM rule case*	*Reference case*	*No NRLM rule case*
Distillate prices (2003 cents per gallon)									
Residential	132.7	120.4	120.5	114.9	114.2	115.1	115.8	117.0	117.0
Commercial	97.3	90.3	90.2	86.9	84.4	88.5	85.6	89.2	86.2
Industrial	100.2	94.2	93.8	93.3	86.9	98.3	88.0	98.5	89.1
Transportation	150.4	151.0	150.6	147.5	145.5	148.1	145.8	147.1	144.2
Electric Power	89.8	81.3	81.5	74.4	73.8	74.5	75.1	75.9	76.7
Composite	136.7	134.4	134.1	131.0	128.6	132.8	129.6	133.5	129.2
Distillate supply (million barrels per day)									
Refinery production	3.76	4.21	4.20	4.64	4.65	4.76	4.87	4.93	5.07
Imports	0.22	0.41	0.41	0.31	0.29	0.34	0.22	0.33	0.19

incurred in providing service to those members. Section 319 provides that, under certain actions approved or accepted by the FERC, gains realized by a rural electric cooperative from a voluntary exchange or involuntary conversion of certain property are excluded in determining whether that cooperative meets the 85-percent test. This provision applies only to the extent that the gain would qualify for deferred recognition under tax laws or the replacement property is used to generate, transmit, distribute or sell electricity or natural gas. This provision represents a level of detail that is not characterized in NEMS.

Low-Sulfur Diesel Fuel Production Credit

Sections 338 and 339 contain provisions allowing small business refiners a 25-percent credit for production of ultra-low-sulfur diesel fuel (15 parts sulfur per million or less), with additional provisions for expensing the remaining 75 percent of the capital investment. Current law does not provide a credit for the production of low-sulfur diesel fuel. The Act allows a small business refiner to claim a credit at a capture rate equal to about 5 cents per gallon for each gallon of low-sulfur diesel fuel produced in compliance with the Highway Diesel Fuel Sulfur Control Requirements law. The credit is a qualified business credit under Section 169(c) of the Act. The existing carry-back and carry-forward provisions for a qualified business credit apply [*14*]. The effective date for this provision is December 31, 2002.

Taxpayers may currently recover the cost of investments in refinery property through annual depreciation deductions. A separate expensing provision permits small business refiners to deduct as an expense up to 75 percent of the costs paid or incurred in making upgrades to comply with the EPA's Highway Diesel Fuel Sulfur Control Requirements.

Small business refiners (up to 205,000 barrels per day and up to 1,500 employees in refining) can claim a tax credit of up to 25 percent of the capital investment costs incurred since 2003 for producing ultra-low-sulfur diesel. Most of the credit would result from refining the first 155,000 barrels per day, with *pro rata* credits for the next 50,000 barrels. The credit expires 1 year after EPA's applicable ultra-low-sulfur diesel deadline or by the end of 2009. Because NEMS does no model individual companies, these tax provisions are not included in the *AEO2005* reference case.

Marginal Wells Tax Credit

Section 341 creates a new tax credit of up to $3 per barrel for the production of crude oil and a credit of up to $0.50 per thousand cubic feet for the production of natural gas from qualified marginal wells. A marginal well is defined as one that produces less than 25 barrels per day of oil equivalent and produces water at a rate not less than 95 percent of total well effluent. Full credit is provided to such marginal wells at reference prices less than or equal to $15 per barrel for oil and $1.67 per thousand cubic feet for natural gas [*15*]. The credit declines linearly to zero when reference prices, adjusted for inflation, reach $18 per barrel of oil and $2 per thousand cubic feet of natural gas. The tax credit applies to the first 1,095 barrels of oil equivalent produced, and the limit is reduced in proportion to the numbers of days in the taxable year for which the well is not in production. The tax credit takes effect in taxable years beginning after December 31, 2004. Because NEMS does not contain a separate marginal well category, the impact of this legislative provision is not quantified in *AEO2005*.

Green Building Bonds

Section 701 contains a brownfields demonstration program that provides tax-exempt status for facility bonds issued to finance qualified "green" buildings and sustainable design projects. The program, designed to encourage the use of solar photovoltaic and fuel cell generation, applies to bonds issued from January 1, 2005, through December 31, 2009; however, projects must be nominated by a State or local government and meet several criteria in addition to the specific green or sustainable criteria. For example, eligible projects must include a brownfields site, be of a certain size, provide a certain level of employment, not include a sports stadium or restaurant, and receive State or local government resources of at least $5 million. Because of the process involved and the site- and company-specific nature of the provision, it is not characterized in the *AEO2005* reference case.

Tax Incentives for Alaska Natural Gas Pipeline and Gas Processing Facilities

Section 706 provides a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. The expected return on equity for the pipeline was lowered to reflect this provision in *AEO2005*.

Section 707 extends the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces

carbon dioxide (CO_2) for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision would be effective for costs incurred after 2004. For *AEO2005*, lowering the expected charges for gas treatment on the North Slope captured this provision.

Extension and Expansion of the Production Tax Credit for Renewable Electricity

Section 710 expands application of the renewable electricity PTC to wind, closed-loop biomass, and poultry-litter plants in service by December 31, 2005 [*16*]. Eligibility for a modified PTC is also extended to geothermal, solar, small irrigation hydropower, open-loop biomass, municipal solid waste, and landfill gas facilities, also with a December 31, 2005, in-service date. This change has been incorporated in *AEO2005*.

Modified Alternative Minimum Tax Rules for the PTC and Alcohol Fuels Tax Credit

The law exempts the alcohol fuel tax credit (Section 40 of the Internal Revenue Code) and the first 4 years of the PTC (Section 45 of the Internal Revenue Code) from tax liability under the Alternative Minimum Tax (AMT), allowing businesses with AMT liability to recover the full value of the affected tax credits. This provision is not included in the *AEO2005* reference case, because EIA assumes that these tax credits are generally able to be used at full value.

Section 45 Tax Credit for Coal Products

The refined coal provisions in Section 710 establish Section 45 tax credits for producers of qualified refined coal products. The refined product must be at least 50 percent higher in market value than the coal or high-carbon fly ash feedstock, and combustion of the refined product must result in 20 percent less emissions of NO_x and either SO_2 or mercury than the feedstock. The refined coal must be sold for the purpose of creating steam. This provision represents a level of detail that is not characterized in NEMS.

Alcohol Alternative Minimum Tax

Section 711 allows the alcohol income tax credit, biodiesel income tax credit, and small ethanol producer income tax credit to offset liability under the AMT. The small ethanol producer credit applies only to firms with capacity of 15 million gallons per year or less. Because NEMS does not model individual tax obligations, these changes are not incorporated in the *AEO2005* reference case.

Suspension of Duties on Nuclear Steam Generators and Reactor Vessel Heads

Section 714 extends from January 31, 2006, to January 31, 2008, the period in which nuclear steam generators can enter the United States duty-free. The law allows nuclear reactor vessel heads to enter the United States duty-free through January 31, 2008, suspending the current 3.3-percent duty. This provision represents a level of detail that is not characterized in NEMS.

Disposition of Transmission Property to Implement FERC Restructuring

Section 909 allows companies to spread capital gains from the sale of transmission assets over 8 years. This provision applies to property sold by a utility to comply with FERC electricity market restructuring efforts. Money from the sale must be used to buy reinvestment property within 4 years of the initial transaction. This restructuring provision is not incorporated in the *AEO2005* reference case.

Tax Evasion Provisions

Subtitle C, Part III, of Title VIII of the Act contains 21 provisions related to fuel tax evasion. Some of the more pertinent provisions and economic impacts are described below. Because NEMS does not model oil and gas income statements, these changes are not incorporated into *AEO2005*.

- Section 853 relates to taxation of aviation-grade kerosene and moves the point of taxation of aviation fuel to the supply rack. Fuel used in commercial aviation that is removed from any refinery or terminal and placed directly into the fuel tank of an aircraft for use in commercial aviation will be taxed at 4.3 cents per gallon. The regulation also stipulates that certain refueler trucks, tankers, and tank wagons be treated as part of a terminal. The person who uses the fuel for commercial aviation will be liable for and pay the tax. These regulations apply after December 31, 2004, and have no stated expiration date.
- Sections 860 and 861 provide clarifications and requirements for exemptions from taxes imposed on the removal of taxable fuel from any refinery or terminal. These amendments take effect on March 1, 2005. Exemptions were already allowed for bulk transfers to registered terminals or refineries. Section 860 clarifies that the transfer must occur by pipeline or vessel. Clarification is provided for the registration of such pipelines or vessels, the requirement to display proof of

registration, and the penalties for failure to display registration.

- Section 870 covers tax refunds for re-refined transmix [*17*] and diesel fuel blendstocks that were previously taxed. This amendment applies to fuel removed, sold, or used after December 31, 2004, and it has no stated expiration date. The Act redefines diesel fuel contaminated with transmix as a taxable diesel fuel if it is suitable for use in a highway vehicle or train. If the fuel is re-refined and then sold into nonroad markets (tax-free), it can qualify for tax refunds.

Working Families Tax Relief Act of 2004

The Working Families Tax Relief Act of 2004 [*18*] was signed into law on October 13, 2004. Primarily, the Act reduces taxes for individuals and businesses. At least two provisions relate to energy.

Depletion of Marginal Properties

Section 314 extends to oil and gas an exemption for marginal properties from the 100 percent of net income limitation on the percentage of assets that can be depleted in a year for tax purposes. In computing taxable income, oil and gas producers generally receive a reasonable allowance for depletion and for depreciation of improvements, based on the amount of resource extracted. Under current law, the deduction cannot exceed 100 percent of taxable income from the property (computed without allowance for depletion). An exemption from the limitation, allowing the deduction to exceed 100 percent of taxable income for production from marginal properties expired on December 31, 2003.

This provision extends the exemption to January 1, 2006. The exemption is applicable only to "marginal production," which is defined as production coming from property that is a stripper well property or a property from which substantially all the production is heavy oil (weighted average gravity of 20 degrees API or less). A stripper well property is a property from which the average production per well is less than 15 barrels of crude oil equivalent per day. Because production from stripper well properties and production of heavy oil are not projected separately from total oil and gas production in the EIA modeling framework, the impact of this provision is not quantified in *AEO2005*.

Qualified Vehicles

Sections 318 and 319 repeal the phaseout of credits allowed for qualified electric and clean fuel vehicles for property acquired in 2004 and 2005. For vehicles acquired in 2006, the 2004 and 2005 credits of $2,000 for clean fuel vehicles and $4,000 for electric vehicles are reduced by 75 percent. This provision is not included in *AEO2005*.

Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005

H.R. 4837, The Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005 [*19*], was signed into law on October 13, 2004. The Act provides for construction to support the operations of the U.S. Armed Forces and for military family housing. It also provides funds to help citizens in Florida and elsewhere in the aftermath of multiple hurricanes and other natural disasters. In addition, it authorizes construction of an Alaska Natural Gas Pipeline.

Alaska Natural Gas Pipeline Loan Guarantee

Section 116 gives the Secretary of Energy authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower 48 States. The authority would expire 2 years after the issuance of a final certificate of public convenience and necessity. In aggregate, the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction), (2) $18 billion dollars (indexed for inflation at the time of enactment), and (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The impact of the loan guarantee is reflected in *AEO2005* by a reduction of the expected return on debt and an increase in the percentage of pipeline costs financed through debt. Additional assistance related to the construction of the Alaska Natural Gas Pipeline is provided in the American Jobs Creation Act of 2004.

State Renewable Energy Requirements and Goals: Status Through 2003

As of the end of 2003, 15 States had legislated programs to encourage the development of renewable energy for electricity generation. Of the 17 programs (two States have multiple programs), 9 are renewable portfolio standards (RPS), 4 are renewable energy mandates, and 4 are renewable energy goals.

Renewable Portfolio Standards

The type of program used most frequently by the States is an RPS requiring that some specified

percentage of electricity supply be provided by qualifying renewable energy sources (Table 6). Most State RPS programs were initiated when privately owned electric utilities were being deregulated, in order to ensure their continued investment in renewables.

Key differences among the State RPS programs include their definitions of qualifying renewables, alternatives to new renewable capacity, approaches to cost recovery, opt-out provisions, and enforcement mechanisms. For example, RPS definitions of qualifying renewable technologies vary widely among the States. Landfill gas, solar thermal electric, solar photovoltaic, and wind energy are acceptable in all nine RPS States, but the rules vary for other technologies. Some also include alternatives to new capacity, such as natural-gas-powered fuel cells or solar thermal water heating. Some favor certain renewable energy technologies, especially solar, by offering more than one credit per kilowatthour. This practice may stimulate favored technologies but reduce the effective size of the RPS if they are developed.

The States use several approaches for funding their RPS programs, including passing the higher costs directly to all utility ratepayers, applying charges on selected categories of sales, or encouraging voluntary purchases through "green power" programs. Most call for reducing or delaying RPS requirements if costs are excessive ("cost-outs"). They may also reduce or eliminate RPS requirements for non-cost reasons, such as if the entities are deemed not creditworthy or if existing contracts meet all the utility's requirements.

Most State RPS programs do not appear to have specific enforcement procedures, except for revoking operating licenses. Some provide for cost penalties for unmet requirements, payments into research and development funds, fines, and other sanctions; however, collaboration and cooperation appear to be the preferred enforcement tools. Through the end of 2003, no electric utility in any State had incurred a penalty for noncompliance with a State RPS.

Mandates

Four States have mandates that narrowly specify the new renewable capacity required (Table 6). Iowa's 1983 mandate, the oldest, ordered its three investor-owned utilities to develop 105 megawatts of new renewable energy capacity, with each utility's share based on its share of peak demand. Minnesota's 1994 mandate required Xcel Energy to acquire 425 megawatts of wind capacity by December 31, 2002, plus

Table 6. Basic features of State renewable energy requirements as of December 31, 2003

State	Part of deregulation	Initial year enacted	Beginning and last specified requirements	Accepts existing capacity	Out-of-State supply	Credit trading
Renewable Portfolio Standards						
Arizona	*Yes*	*1996*	*0.2-1.1% of sales, 2001-2007*	*No*	*Solar only*	*Yes*
California	*No*	*2002*	*+1% of sales per year, to 20.0% by 2017*	*Yes*	*Yes*	*No*
Connecticut	*Yes*	*2003*	*6.5-10.0% of generation, 2003-2010*	*Yes*	*Yes*	*Yes*
Maine	*Yes*	*1997*	*30.0% of sales by 1999*	*Yes*	*Yes*	*Yes*
Massachusetts	*Yes*	*1997*	*1.0-4.0% of sales, 2003-2009*	*No*	*Yes*	*Yes*
Nevada	*No*	*2001*	*5.0-15.0% of sales, 2003-2013; 5% of requirements must be solar*	*Yes*	*Yes*	*Yes*
New Jersey	*Yes*	*1999*	*3.0-6.5% of sales, 2001-2008*	*Yes*	*Yes*	*Yes*
New Mexico	*No*	*2002*	*5.0-10.0% of sales, 2006-2011*	*Yes*	*Yes*	*Yes*
Wisconsin	*No*	*1999*	*0.5-2.2% of sales, 2001-2011*	*Yes*	*Yes*	*Yes*
Mandates						
Iowa	*No*	*1983*	*105 megawatts (no set date)*	*No*	*NS*	*No*
Minnesota	*No*	*1994*	*1,125 megawatts wind by 2010 + 125 megawatts biomass*	*No*	*Yes*	*No*
Texas	*No*	*1999*	*400-2,000 megawatts, 2003-2009*	*No*	*Yes*	*Yes*
Wisconsin	*No*	*1997*	*50 megawatts by 2000*	*No*	*No*	*No*
Goals						
Hawaii	*No*	*2001*	*9.0% of sales by 2010*	*Yes*	*NA*	*No*
Illinois	*No*	*2001*	*15.0% of sales by 2020*	*NS*	*No*	*No*
Minnesota	*No*	*2003*	*1.0-10.0% of sales, 2005-2015*	*NS*	*Yes*	*Yes*
Pennsylvania	*Yes*	*1998*	*Individual agreements with five utilities*	*NS*	*NS*	*NS*

125 megawatts of biomass capacity, in exchange for storing additional nuclear waste at its Prairie Island plant. An additional 700 megawatts of new wind capacity has since been added to the mandate, some of which must come from small facilities (2 megawatts of capacity or less). The wind requirements are being met, but Minnesota's biomass requirements have not been met because of technological and financial difficulties. Additional legislation in 2003 requires a power purchase agreement for 10 to 20 megawatts of biomass energy, operational by 2005, at no more than $55 per megawatthour.

The 1999 renewable energy mandate in Texas requires the installation of 2,000 megawatts of new renewable generating capacity by 2009. The Texas mandate has resulted in more new renewable capacity than any other State-level requirement to date, including 1,180 megawatts of new wind capacity installed by the end of 2003 as well as small amounts of landfill gas and other renewable capacity. A fourth State, Wisconsin, in 1998 required four eastern utilities to install 50 megawatts of new renewable energy capacity by December 31, 2000, a requirement that was met by the utilities.

Voluntary Goals, Objectives, and Settlements

Four States—Hawaii, Illinois, Minnesota, and Pennsylvania—have instituted programs that encourage, but do not require, new renewable energy capacity (Table 6). Hawaii's 2001 goal resembles a typical RPS, except for the absence of penalties and the inability to obtain supplies from other States. Illinois in 2001 set targets for electricity production from qualified renewables; however, the goal is not supported by schedules, a menu of acceptable renewable technologies or alternatives other than solar and wind, compliance mechanisms, credit trading, or most of the other features of State RPS programs. In Minnesota, utilities other than Xcel are subject to the State's 2001 Renewable Energy Objective, which requires a "good faith effort" to increase renewable energy's contribution. The objective is considered a mandate for Xcel. In 1996, five Pennsylvania utilities settled restructuring cases on terms requiring a minimum percentage of renewables. Among these settlements, only the Pennsylvania Electric Company (PECO) energy program was implemented; however, the five utilities also established four sustainable energy funds that are reported to have supported development of significant amounts of new wind and other generating capacity.

Results

State renewable portfolio standards, mandates, and goals are all relatively new, with the majority just now entering their initial compliance years. Because of alternative compliance options and adjustments that would likely be made if renewable energy costs are found excessive in the future, it is difficult to assess the future impacts of these programs. Nevertheless, through the end of 2003, requirements or goals for new renewable energy capacity in 15 States has resulted in an estimated 2,335 megawatts of new renewable electricity supply (Table 7). Most of the new capacity is fueled by wind power (2,183 megawatts), with smaller amounts of landfill gas, hydroelectricity, biomass, and solar photovoltaic technologies. The 321 megawatts that entered service in the nine RPS States accounted for 14 percent of total new renewable energy capacity from RPS, mandates, and goals through 2003. State mandates—especially in Texas—have led to the development of 2,004 megawatts of renewable capacity, 86 percent of the total. Nearly 51 percent (1,186 megawatts) of all the new capacity was installed in Texas. Recognizing that States with renewable energy requirements have not added capacity as rapidly as projected in earlier forecasts, projections for new renewable energy capacity resulting from State RPS programs, mandates, and nonmandatory goals are reduced in *AEO2005*.

Update on State Air Emission Regulations That Affect Electric Power Producers

Several States have recently enacted air emission regulations that will affect the electricity generation sector. The regulations are intended to improve air quality in the States and assist them in complying with the revised 1997 National Ambient Air Quality Standards (NAAQS) for ground-level ozone and fine particulates. The affected States include Connecticut, Massachusetts, Maine, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oregon, Texas, and Washington. The regulations govern emissions of NO_x, SO_2, CO_2, and mercury from power plants.

Where firm compliance plans have been announced, State regulations are represented in *AEO2005*. For example, installations of SO_2 scrubbers and selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) NO_x removal technologies associated with the largest State program, North Carolina's "Clean Smokestacks Initiative," are included. Overall, the *AEO2005* forecast includes 22 gigawatts of announced SO_2 scrubbers, 27 gigawatts of announced SCRs, and 3 gigawatts of announced SNCRs.

In addition to the existing regulations, Governor George Pataki of New York has announced proposed

greenhouse gas reduction targets for the State of New York and has invited nine other States (Connecticut, Delaware, Maryland, Maine, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Vermont) to participate in a future "Northeast CO_2 cap and trade" program. The program requires only CO_2 trading among power plants but would also allow trading of other emissions allowances among power plants burning coal, natural gas, or oil. The first Commissioner-level meeting was held in September 2003, and a final agreement is expected to be in place by April 2005. Maryland and Pennsylvania are participating in discussions but have not committed to participation in the program.

Table 8 summarizes current State regulatory initiatives on air emissions, and the following section gives brief descriptions of programs in the States that have enacted air emissions regulations more stringent than Federal regulations. State-level initiatives to limit greenhouse gas emissions without directly regulating the electricity generation sector, which are not discussed here, include the following: California law A.B. 1493, enacted in July 2002, which sets CO_2 pollution standards for 2009 model vehicles and those sold later (see "Legis.lation and Regulations,"page 27); Georgia's transportation initiative, which is focused on expanding the use of mass transit and other transportation sector measures; Minnesota's Releaf Program, which encourages tree planting as a way to reduce atmospheric CO_2 levels; Nebraska's carbon sequestration advisory committee, which proposes to sequester carbon through agricultural reform practices; North Carolina's program to develop new technologies for solid waste management practices that reduce emissions; RPS programs being adopted by several States (see discussion of State renewable energy requirements and goals, above); and Wisconsin's greenhouse gas emissions inventory.

Connecticut. The Connecticut "Abatement of Air Pollution" regulation was enacted in December 2000, and revisions are being made on an ongoing basis. It limits SO_2 and NO_x emissions from all NO_x budget program (NBP) sources that are more than 15 megawatts or require fuel input greater than 250 million Btu per hour [*20*]. The regulation applies to the electricity generation sector, the cogeneration sector, and industrial units. The NO_x limit is 0.15 pound per million Btu of heat input. The SO_2 limit applies to NBP sources that are also Acid Rain Program sources, and

Table 7. Estimated capacity contributing to State renewable energy programs through 2003 (megawatts, nameplate capacity)

State	Biomass	Geo-thermal	Conventional hydro-electric	Landfill gas	Municipal solid waste	Ocean or tidal	Solar photo-voltaics	Wind	Other/ unknown	Total
Renewable Portfolio Standards										
Arizona	0	0	0	5	0	0	9	0	0	14
California	0	0	20	6	0	0	0	175	0	201
Connecticut	0	0	0	0	0	0	0	0	0	0
Maine	0	0	0	0	0	0	0	0	0	0
Massachusetts	0	0	0	8	0	0	0	1	0	9
Nevada	0	0	0	0	0	0	0	0	0	0
New Jersey	0	0	0	0	0	0	0	0	0	0
New Mexico	0	0	0	0	0	0	0	0	0	0
Wisconsin	0	0	0	3	0	0	0.02	94	0	97
Mandates										
Iowa	16	0	0	0	0	0	0	237	7	260
Minnesota	25	0	0	0	0	0	0	476	0	501
Texas	5	0	10	31	0	0	0.2	1,140	0	1,186
Wisconsin	7	0	0	0	0	0	0	50	0	57
Goals										
Hawaii	0	0	0	0	0	0	0	0	0	0
Illinois	0	0	0	0	0	0	0	0	0	0
Minnesota	0	0	0	0	0	0	0	0	0	0
Pennsylvania	0	0	0	0	0	0	0	10	0	10
Total	53	0	30	53	0	0	9.22	2,183	7	2,335
Share of Total	2.3%	0%	1.3%	2.3%	0%	0%	0.4%	93.5%	0.3%	100.0%

the limit is 0.3 percent sulfur in fuel and 0.33 pound per million Btu. Modifications are being made to the current NBP rules to provide incentives in the form of allowances for renewable energy and energy efficiency programs [21].

In May 2003, the Connecticut General Assembly passed legislation (Connecticut Public Act 02-64) requiring coal-fired power plants to remove 90 percent of the mercury from smokestack emissions (or a maximum of 0.6 pound of mercury emitted per trillion Btu input, which is equivalent to 0.005 to 0.007 pound per gigawatthour) by July 2008. The legislature has recommended that the State Department of Environmental Protection consider stricter limits by July 2012 [22].

Table 8. Existing State air emissions legislation with potential impacts on the electricity generation sector

State	Activities	Emissions limits
Connecticut	*Regulations for electric utility, industrial cogeneration, and industrial units*	
	SO_2 emissions Phase I limit by 2002	*0.55 pound per million Btu input*
	SO_2 emissions Phase II limit by 2003	*0.33 pound per million Btu input*
	NO_x limit	*0.15 pound per million Btu input*
	Mercury emissions limit by July 2008	*90% removal (or maximum of 0.6 pound mercury emitted per trillion Btu input, equivalent to 0.005-0.007 pound mercury per gigawatthour)*
Maine	*Regulation for greenhouse gas emissions reduction from all sectors*	
	Greenhouse gas emissions by 2010	*At 1990 levels*
	Greenhouse gas emissions by 2020	*10% below 1990 levels*
	Greenhouse gas emissions in the "long term"	*75% to 80% below 2003 levels*
Massachusetts	*Multi-pollutant cap for existing power plants*	
	SO_2 emissions in 1999: 6.7 pounds per megawatthour	
	SO_2 cap 2004 or 2006 (depending on compliance strategy)	*6.0 pounds per megawatthour*
	SO_2 cap 2006 or 2008 (depending on compliance strategy)	*3.0 pounds per megawatthour*
	NO_x emissions in 1999: 2.4 pounds per megawatthour	
	NO_x cap 2004 or 2006 (depending on compliance strategy)	*1.5 pounds per megawatthour*
	CO_2 emissions (current): 2,200 pounds per megawatthour	
	CO_2 cap 2006 or 2008 (depending on compliance strategy)	*1,800 pounds per megawatthour*
	Mercury emissions cap, Phase I, January 2008	*85% removal from 2004 levels or 0.0075 pound per gigawatthour*
	Mercury emissions cap, Phase II, October 2012	*95% removal from 2004 levels or 0.0025 pound per gigawatthour*
Missouri	*Summer NO_x regulations by May 2004*	*0.18 to 0.35 pound per million Btu input*
New Hampshire	*Regulation for existing fossil-fuel power plants*	
	SO_2 emissions in 1999: 48,000 short tons	
	SO_2 cap 2006	*7,289 short tons*
	NO_x emissions in 1999: 9,000 short tons	
	NO_x cap 2006	*3,644 short tons*
	CO_2 emissions in 1990: 5,426 thousand short tons	
	CO_2 emissions in 1999: 5,594 thousand short tons	
	CO_2 cap 2006	*5,426 thousand short tons*
New Jersey	*Greenhouse gas emissions in 1990: 136 million metric tons carbon dioxide equivalent*	
	Greenhouse gas emissions 2005	*3.5% below 1990*
New York	*Regulations for electric utilities, cogenerators, and industrial units*	
	SO_2 Phase I limit January 2005, 25% below allocation	*197,046 short tons*
	SO_2 Phase II limit January 2008, 50% below allocation	*131,364 short tons*
	NO_x limit beginning in October 2004 (October 1 to April 30 cap)	*39,908 short tons*
North Carolina	*Regulations for existing coal-fired plants only*	
	SO_2 emissions in 1999: 429,000 short tons	
	SO_2 cap 2009	*250,000 short tons*
	SO_2 cap 2013	*130,000 short tons*
	NO_x emissions in 1999: 178,000 short tons	
	NO_x cap 2009	*56,000 short tons*
Oregon	*CO_2 regulation for new or expanded power plants*	*675 pounds per megawatthour*
Texas	*Senate Bill 7, SO_2 and NO_x caps for grandfathered sources*	
	SO_2 cap 2003	*595,000 short tons*
	NO_x cap 2003	*302,000 short tons*
Washington	*CO_2 regulations for new fossil-fueled power plants*	*20% reduction over 30 years*

In addition, Connecticut enacted a law in June 2004 called "An Act Concerning Climate Change," Public Act No. 04-252. The goal of the legislation is to reduce emissions of greenhouse gases from sources in Connecticut to 1990 levels by 2010 and to 10 percent below 1990 levels by 2020, and it establishes a process to determine reduction goals beyond 2020. The Act covers electricity generators, fleet vehicles, industrial facilities, and commercial establishments; however, there are no enforcement procedures in the law. There is a requirement for the Governor's Steering Committee on Climate Change to develop a Climate Action Plan by January 2005, and for the Commissioner of Environmental Protection to establish a regional greenhouse gas registry that will collect emissions data.

Maine. Maine enacted a climate change statute—"An Act to Provide Leadership in Addressing the Threat of Climate Change" (Public Law 2003, Chapter 237, H.P. 622, L.D. 845)—in June 2003 [*23*]. The statute requires the establishment of a greenhouse gas emissions inventory for State-owned facilities and State-funded programs and calls for a plan to reduce emissions to 1990 levels by 2010. It specifies that carbon emission reduction agreements must be signed with at least 50 businesses and nonprofit organizations by January 2006, and that Maine must participate in a regional greenhouse gas registry. The goals of the statute are a reduction of greenhouse gases to 1990 levels by January 2010, a reduction to 10 percent below 1990 levels by 2020, and a reduction to 75 and 80 percent below 2003 levels "in the long term." It authorizes the Department of Environmental Protection to submit to the Legislature a State climate action plan to meet the goals of the statute [*24*].

Massachusetts. The Massachusetts Department of Environmental Protection air pollution control regulations (310 CMR 7.29, "Emissions Standards for Power Plants"), approved in May 2001 [*25*], apply to six existing older power plants in Massachusetts. There are two options for utilities to comply with the regulations: either "repower" (defined as replacing existing boilers with new ones that meet the environmental standards, switching fuel to low-sulfur coal, or switching from coal to natural gas); or choose a standard path that includes installing low-NO_x burners, installing SO_2 scrubbers, and installing SCR or SNCR equipment.

The rule offers an incentive for a fuel shift by delaying the compliance deadline to October 2008 for any facility choosing to repower. Plants using other techniques, such as pollution control equipment, must comply by October 2006. The SO_2 standard is 6.0 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering) and 3.0 pounds per megawatthour by October 2006 (standard) or October 2008 (repowering). The NO_x standard is 1.5 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering). The SO_2 and NO_x regulations are considered by the State to be more stringent than CAAA90 would imply. Most of the facilities are choosing the repowering mode rather than the standard mode of compliance. Compliance plans have been submitted for the six power stations affected: Brayton Point, Salem Harbor, Somerset, Mount Tom, Canal, and Mystic stations [*26*].

The CO_2 standard annual facility cap is based on 3 years of data as of October 2004 (standard) or October 2006 (repowering) and an annual facility rate of 1,800 pounds CO_2 per megawatthour as of October 2006 (standard) or October 2008 (repowering) [*27*]. Credits for off-site reductions of CO_2 emissions can be obtained through carbon sequestration or renewable energy projects. The Massachusetts Department of Environmental Protection is developing regulations that would determine what projects could qualify as reductions. Greenhouse gas banking and trading regulations are also being developed. Plants that fail to achieve the reductions may purchase emissions credits.

The State of Massachusetts published final mercury emissions regulations in June 2004 that apply to the State's four largest existing coal-fired power plants (Brayton Point, Mount Tom, Salem Harbor, and Somerset Station) [*28*]. The regulations require compliance with at least one of the following standards: reduce mercury emissions by 85 percent from 2004 levels by January 2008 or a facility average mercury emissions rate of 0.0075 pound per gigawatthour or less. The affected facilities must reduce their mercury emissions by 95 percent from 2004 levels by October 2012, or achieve a facility average mercury emissions rate of 0.0025 pound per gigawatthour or less. The Massachusetts mercury emissions regulations are more stringent than EPA's proposed mercury emissions regulations as of January 2004 (69 CFR 4651).

Missouri. The Missouri NO_x rule, "Emission Limitation and Emissions Trading of Oxides of Nitrogen" (Rule 10 CSR 10-6.350) applies to fossil-fueled capacity larger than 25 megawatts. The emissions cap is based on a unit's heat input. Power plants had to be in compliance by May 2004. Allowances can be banked, with some restrictions, and some exchange of

allowances is allowed [*29*]. The seasonal NO_x limits (from May to September of each year) vary by county and generally range from 0.18 to 0.35 pound per million Btu.

New Hampshire. New Hampshire has enacted legislation—the "Clean Power Act" (House Bill 284)—to reduce emissions of SO_2, NO_x, CO_2, and mercury from existing fossil-fuel-burning steam-electric power plants. Governor Jeanne Shaheen signed the Act into law in May 2002, and implementing regulations have been finalized [*30*]. The legislation applies to the State's three existing fossil-fuel power plants only and does not apply to new capacity. The plants must either reduce emissions, purchase emissions credits from plants outside New Hampshire that have achieved such reductions, or use some combination of these strategies. Compliance plans submitted to the New Hampshire Department of Environmental Services are under review.

One of the affected plants is Schiller, a 150-megawatt coal-burning power plant made up of three 50-megawatt units. Part of the compliance action, the "Northern Wood Power Project," is the conversion of one of Schiller's 50-megawatt units from coal to a fluidized-bed combustor that will burn biomass. The converted power plant will burn wood chips, sawmill residue, and other woody material. The action is, in part, a result of the Massachusetts RPS program, under which plants in States neighboring Massachusetts can convert from coal to biomass and qualify for the program. Thus, Schiller's conversion from coal to biomass counts toward meeting both the Massachusetts RPS and the New Hampshire multi-pollutant requirements. The conversion, which is expected to cost $70 million (about $1,500 per kilowatt), is planned for completion by the end of 2005.

The SO_2 annual cap under New Hampshire's Clean Power Act is 7,289 short tons by 2006, which amounts to a 75-percent reduction from Phase II Acid Rain legislation requirements and an 85-percent reduction from 1999 emission levels. The NO_x annual cap is 3,644 short tons by 2006, which amounts to a 60-percent reduction from 1999 emission levels. The CO_2 annual cap is 5,425,866 short tons by 2006, which amounts to a 3-percent reduction from 1999 levels.

New Jersey. New Jersey's goal is to reduce Statewide emissions of greenhouse gases from all sectors by 3.5 percent from 1990 levels by 2005. "Covenants" have been signed, pledging organizations to reduce their greenhouse gas emissions in accordance with the State goal [*31*].

New York. New York's "Acid Deposition Reduction Budget Trading Programs"—Title 6 NYCRR Parts 237 and 238—were approved by the State Environmental Board in March 2003 and became effective in May 2003 [*32*], but implementation of the rule has been delayed by a court order. The NO_x regulations apply to electricity generators of 25 megawatts or greater, and the SO_2 regulations apply to all CAAA90 Title IV sources, including electric utilities and other sources of SO_2 and NO_x, such as cogenerators and industrial facilities. NO_x emissions were limited to 39,908 short tons beginning in October 2004. This is a non-ozone season cap (October 1 to April 31), based on the same rate (0.15 pound per million Btu) as the NO_x cap in the current State emissions regulation. SO_2 emissions are limited in two phases: Phase I, beginning in January 2005, limits SO_2 to 25 percent below Title IV allocations (197,046 short tons); Phase II, beginning in January 2008, increases the limit to 50 percent below Title IV allocations (131,364 short tons) [*33*]. A governor's task force was established in June 2001 to recommend greenhouse gas limits.

North Carolina. The General Assembly of North Carolina has passed the "Clean Smokestacks Act"—officially called the "Air Quality/Electric Utilities Act" (S.B. 1078)—which requires emissions reductions from 14 existing coal-fired power plants in the State. It was signed into law in June 2002. Under the Act, North Carolina power companies must reduce NO_x emissions from 178,000 short tons in 1999 to 56,000 short tons by 2009 and SO_2 emissions from 429,000 short tons in 1999 to 250,000 short tons by 2009 and 130,000 short tons by 2013. Progress Energy Carolinas, Inc., and Duke Power have submitted compliance plans to the North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission. The utilities will comply with the Act by installing scrubbers and SNCR technology at their plants. Duke Power and Progress Energy have reported compliance costs for SO_2 and NO_x control, with SNCR costs ranging from $4.93 to $63.70 per kilowatt and scrubber costs ranging from $113 to $414 per kilowatt [*34*].

The Act requires the Department of Environment and Natural Resources to evaluate issues related to the control of mercury and CO_2 emissions and recommends the development of standards and plans to control them. In 2003, the Department of Air Quality prepared reports on mercury [*35*] and CO_2 [*36*] emissions reductions for the State, in the first of three sets of reports to be submitted to the Environmental Management Commission and the Environmental Review Commission. The objective of the 2003 report was to

provide general background on the topic of climate change and to define the scope of efforts needed to meet the legislative requirements. The 2004 and 2005 reports will build on this background, report on any developments in the Federal Government, and recommend courses of action that may follow [*37*].

The Act also requires North Carolina to persuade other States and power companies to reduce their emissions to similar levels and on similar timetables. The Act specifically mentions that discussions should be held with the Tennessee Valley Authority (TVA) to determine its emissions reduction policies. A meeting was held between the Department of Environment and Natural Resources/Department of Air Quality and TVA in August 2002 to discuss actions planned by TVA that would be comparable to the Clean Smokestacks Act. TVA presented its plans to add scrubbers to five additional power plants, primarily in the eastern portion of the TVA system, beginning with its Paradise plant in 2006. TVA plans to complete installation of the new scrubbers by 2010. TVA also plans to install the first eight SCR systems for NO_x control and to have 25 boiler units controlled by 2005, which will reduce NO_x emissions during the ozone season by 75 percent.

Oregon. Oregon has established its first formal State standards for CO_2 emissions from new electricity generating plants. The standards apply to power plants and non-generating facilities that emit CO_2. The Oregon Energy Facility Siting Council originally adopted the rules pursuant to House Bill 3283, which was passed by the Oregon legislature in June 1997, and has subsequently updated the rules, most recently in April 2002 [*38*]. For baseload natural gas plants and non-baseload plants, the standard CO_2 emission rate is 675 pounds per megawatthour, 17 percent below the rate for the most efficient natural-gas-fired plants currently in operation in the United States. The Council has not set CO_2 emission standards for baseload power plants using other fossil fuels. As of 2002, about 90 percent of Oregon's electricity was from hydroelectricity and natural gas and about 8 percent was from coal [*39*].

The Council's definition of a natural-gas-fired facility allows up to 10 percent of the expected annual energy to be provided by an alternative fuel, most likely distillate fuel. Proposed facilities may meet the requirement through cogeneration, using new technologies, or purchasing CO_2 offsets from carbon mitigation projects. It is possible to offset all excess CO_2 emissions through cogeneration offsets alone, and there are no limitations on the geographic location or types of CO_2 offset projects. The Council has set a monetary value that the generators may pay to buy offsets ($0.85 per short ton CO_2, equivalent to $3.12 per ton carbon, set in September 2001) [*40*]. This equates to an offset cost of 0.88 mill per kilowatthour [*41*].

Texas. Texas Senate Bill 7 (S.B. 7) imposes NO_x and SO_2 caps for grandfathered fossil fuel power plants [*42*]. The SO_2 annual cap is 595,000 short tons (East: 532,000, West: 63,000, and El Paso: 0 short tons). The NO_x annual cap is 302,000 short tons (East: 256,000, West: 44,000, and El Paso: 2,000 short tons), both of which had to have been achieved by May 2003. The State-wide caps have been met.

Washington. Washington's House Bill 3141, signed into law in May 2004, requires 20 percent of their CO_2 emissions from new power plants to be offset. Plant owners can either directly or indirectly invest in CO_2 mitigation projects, such as forest preservation or the conversion of buses from diesel to natural gas. Power plant CO_2 emissions must be reduced by 20 percent over a 30-year period. CO_2 emissions can be offset by payments to an independent qualified organization, by direct purchase of permanent carbon credits, or by direct investment in CO_2 mitigation projects. The rate of payment to third parties is fixed at $1.60 per metric ton CO_2 [*43*]. The Washington State Energy Facility Site Evaluation Council may adjust the rate every 2 years, but any decrease or increase may not exceed 50 percent of the current rate.

California Greenhouse Gas Emissions Standards for Light-Duty Vehicles

In July 2002, California Assembly Bill 1493 (A.B. 1493) was signed into law. The law requires that the California Air Resources Board (CARB) develop and adopt, by January 1, 2005, greenhouse gas emission standards for light-duty vehicles that provide the maximum feasible reduction in emissions. In estimating the feasibility of the standard, CARB is required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the standard.

Tailpipe emissions of CO_2, which are directly proportional to vehicle fuel consumption, account for the vast majority of total greenhouse gas emissions from vehicles. A.B. 1493 does not mandate the sale of any specific technology and prohibits the use of the following as options for greenhouse gas reduction: mandatory trip reductions; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicle miles traveled; a ban on any vehicle category; reductions in vehicle weight; or a limitation or reduction on

the speed limit on any street or highway in the State. Given these limitations and the preponderant share of total vehicle greenhouse gas emissions resulting from fuel consumption, improvements in fuel economy are the only practical way to attain any standard that requires a significant reduction in emissions.

CARB released a report on August 6, 2004, detailing the reasons for the proposed rulemaking, providing light vehicle regulations to be considered for adoption, and outlining the required analyses used to develop the proposed regulations. The standards for light-duty vehicle greenhouse gas emissions were adopted in September 2004. The auto industry opposes A.B. 1493 and has filed suit against CARB, stating that the California greenhouse gas emissions standards are preempted by a Federal statute that gives the U.S. Department of Transportation the only authority to regulate fuel economy [*44*]. Given the uncertainty surrounding the possible outcome of this litigation, the A.B. 1493 greenhouse gas emission standards are not represented in the *AEO2005* reference case; however, the standards were analyzed to estimate the potential impact on vehicle prices, greenhouse gas emissions, regional energy demand, and regional fuel prices.

A.B. 1493 Regulation

The greenhouse gas emission standards adopted in September 2004 incorporate emissions associated with vehicle operation, air conditioning operation, refrigerant emissions from the air conditioning system, and upstream emissions associated with the production of vehicle fuel. The emission standards apply to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond. The standards, specified in terms of CO_2 equivalent emissions, apply to two size classes of vehicles: (1) passenger cars and small light-duty trucks with a loaded vehicle weight rating of 3,750 pounds or less, and (2) heavy light-duty trucks with a loaded vehicle weight rating greater than 3,750 pounds and a gross vehicle weight rating less than 8,500 pounds. The CO_2 equivalent emission standard for heavy light trucks also includes noncommercial passenger trucks between 8,500 pounds and 10,000 pounds. The regulation adopted in September 2004 sets near-term emission standards, phased in between 2009 and 2012, and mid-term emission standards, phased in between 2013 and 2016. After 2016, the emissions standards are assumed to remain constant. Table 9 summarizes the CO_2 equivalent standards.

The regulations allow for CO_2 emission reduction credits that can be earned and traded for 2000 through 2008 model year vehicles. If a manufacturer decides to opt into the program before 2009, credits will be earned if average CO_2 equivalent emissions for that manufacturer's fleet are lower than the 2012 standards. The regulations also provide flexibility in complying with the CO_2 emission standards. Manufacturers can apply for alternative compliance credits for eligible 2009 vehicles and later model years if those vehicles achieve greenhouse gas reductions through the use of alternative fuels. In addition, credits are provided for the use of advanced leak reduction air conditioning components and for the use of HFC-152a as the refrigerant. The regulations also set light vehicle nitrous oxide (N_2O) and methane (CH_4) emission standards.

For this analysis, the CO_2 equivalent emission standards were converted to miles per gallon fuel economy equivalents (Table 10) [*45*]. The fuel economy equivalents shown in Table 10 assume that manufacturers will earn the maximum allowable air conditioning credits. The methodology used to estimate the fuel economy equivalents assumes that manufacturers will meet the N_2O and CH_4 standards and includes CO_2 equivalent emissions associated with N_2O and CH_4 emissions, which are generated by the exhaust

Table 9. CARB CO_2 equivalent emission standards for light-duty vehicles, model years 2009-2016

		CO_2 equivalent emission standard (grams per mile)	
Tier	*Model Year*	*Passenger cars and small light trucks (under 3,751 pounds)*	*Heavy light trucks (3,751 to 8,500 pounds)*
Near term	*2009*	*323*	*439*
	2010	*301*	*420*
	2011	*267*	*390*
	2012	*233*	*361*
Mid-term	*2013*	*227*	*355*
	2014	*222*	*350*
	2015	*213*	*241*
	2016	*205*	*332*

catalyst and incomplete combustion. The fuel economy equivalent standards are assumed to remain constant after 2016.

Analysis and Results

Two cases were developed to measure the potential impact of the California light vehicle greenhouse gas emission standards on energy demand, fuel prices, and vehicle prices. The *A.B. 1493 California-only case* assumes that only California will adopt the new standards. The *A.B. 1493 extended case* assumes that New York, Maine, Massachusetts, and Vermont will also adopt the California standards for greenhouse gas emissions for light-duty vehicles. Those States have already adopted California emissions standards applicable to other types of vehicle emissions [*46*].

Both cases examined here assume that fuel economy impacts are limited to those States adopting the regulation and that the fuel economy and sales mix of vehicles sold in non-adopting States remain at levels achieved in the *AEO2005* reference case. Although not addressed in this analysis, it is conceivable that State-based fuel economy regulation could cause unintended shifts in light vehicle markets. State-specified fuel economy standards might inadvertently provide manufacturers an opportunity to maintain or increase profits through the sale of larger, less efficient vehicles (sport utility vehicles, minivans, and large cars) in areas that do not adopt the California standards, while complying with the nationally based CAFE standards.

As noted above, A.B. 1493 allows CO_2 emission credits for early compliance and for the sale of alternative-fuel vehicles. However, this analysis does not attempt to quantify the impact that either would have on the fuel economy required to meet the CO_2 equivalent emission standards.

Impacts on Vehicle Sales and Prices

For States adopting A.B. 1493, it is projected that advanced technologies implemented in conventional light-duty vehicles will account for the majority of the fuel economy improvements needed to achieve the required reductions in CO_2 emissions. For cars, in addition to the fuel economy gains achieved through advanced conventional technologies, increased sales of hybrid and diesel vehicles will be required to meet the fuel economy goal. Relative to the projections in the *AEO2005* reference case, hybrid car sales in those States adopting A.B. 1493 are projected to increase from 5.8 percent to 11.0 percent of total new car sales in 2016, and diesel car sales are projected to increase from 0.3 percent to 0.9 percent of total new car sales in 2016.

As a result of increased use of advanced conventional technologies and increased market penetration of hybrid and diesel vehicles, the average price of a new car in 2016 is projected to increase by $1,860, and the average price of a new truck is projected to increase by $500 (2003 dollars) in both cases in the analysis. These cost estimates do not include the costs associated with credits earned from improved air conditioning systems or the emission control equipment needed to achieve the N_2O and CH_4 emission standards. They do account for increased demand for heavier vehicles, improved performance, and increased fuel economy that is projected to continue throughout the forecast period in the *AEO2005* reference case.

The EIA projections for vehicle sales and price impacts can be compared with those reported in the CARB staff analysis [*47*], which estimates that the average price of new passenger cars and small light trucks will increase by $1,064, and the average price of a new heavy light truck will increase by $1,029, in

Table 10. CARB fuel economy equivalent standards for light-duty vehicles, model years 2009-2016

		Fuel economy equivalent standard (miles per gallon)	
Tier	*Year*	*Passenger cars and small light trucks (<3,751 pounds loaded vehicle weight)*	*Heavy light trucks (3,751 pounds loaded vehicle weight to 8,500 pounds gross vehicle weight)*
Near term	*2009*	*26.4*	*19.5*
	2010	*28.3*	*20.4*
	2011	*31.8*	*21.9*
	2012	*36.2*	*23.6*
Mid-term	*2013*	*36.3*	*23.6*
	2014	*37.1*	*23.9*
	2015	*38.6*	*24.5*
	2016	*39.9*	*25.2*

2016 compared with the price of a model year 2009 base vehicle. Comparisons of the 2016 model year vehicle price to the 2009 base vehicle price implicitly assume that continued consumer demand for increased vehicle weight and performance will have no impact on the cost of complying with the regulation. CARB provided no information about its assumptions for fuel economy, weight, and performance ratings for the 2009 base vehicle.

Impacts on Transportation Energy Use and CO_2 Equivalent Emissions

In the A.B. 1493 California-only case, EIA estimates that total national transportation energy use in 2025 would be reduced by 0.15 million barrels per day (0.7 percent) and CO_2 equivalent emissions would be reduced by 21 million metric tons (0.8 percent) relative to the *AEO2005* reference case projections. In the A.B. 1493 extended case, EIA estimates that total national transportation energy use in 2025 would be reduced by 0.22 million barrels per day (1.1 percent) and CO_2 equivalent emissions by 33 million metric tons (1.2 percent) relative to the *AEO2005* reference case projections.

The CARB staff analysis provides estimated emissions reduction impacts for 2020 and 2030, which allow for a direct comparison with EIA's results for 2020. In the A.B. 1493 California-only case, EIA projects that 2020 light vehicle CO_2 equivalent emissions would be reduced by 14.9 million metric tons (Table 11). CARB's analysis determined that by 2020 CO_2 equivalent emissions from light-duty vehicles would be reduced by 29 million metric tons, approximately double EIA's estimate [*48*].

The difference in projected reductions in CO_2 equivalent emissions in the two analyses can be explained by three key factors. The first is the projected distribution of cars and light trucks in use. The CARB analysis projects that, in 2020, passenger cars and light trucks under 3,750 pounds loaded vehicle weight (so-called "small light trucks") would account for approximately 80 percent of the light-duty vehicle stock and associated vehicle miles traveled. Specifically, passenger cars account for 63.6 percent of the total stock, small light trucks account for 18.2 percent of the total stock, and heavy light trucks account for 18.1 percent of the total stock [*49*]. In comparison, EIA's analysis projects that passenger cars would account for 46.5 percent of the light vehicle stock, and all light trucks, which are predominantly over 3,750 pounds loaded vehicle weight, would account for 53.5 percent [*50*]. This is significant because, as shown in the CARB analysis, passenger cars and small light trucks are required to meet the more stringent CO_2 equivalent standard, which will result in greater projected emission reductions.

Although NEMS does not specifically model light trucks less than 3,750 pounds loaded vehicle weight, light trucks are disaggregated by vehicle class. The fuel economy equivalent standards shown in Table 10 were modified to reflect an assumption that light trucks under 3,750 pounds gross vehicle weight would account for 12.3 percent of new light truck sales [*51*]. As a result, the light truck fuel economy equivalent standard used in EIA's analysis would increase to 26.4 miles per gallon by 2016.

The second significant difference between the two analyses is projected baseline fuel economy. Although no data were available for the baseline fuel economy projected in the CARB analysis, CARB staff informed EIA that their baseline for greenhouse gas emissions from light-duty vehicles does not project increases in new light vehicle fuel economy [*52*]. The *AEO2005* reference case projects that new car fuel economy will increase from 29.5 miles per gallon in 2003 to 30.6 miles per gallon in 2020, and that new light truck fuel economy will increase from 21.8 miles per gallon in 2003 to 24.1 miles per gallon in 2020. As a result, the EIA projection of baseline fuel economy improvement reduces the amount of CO_2 that can be saved by the

Table 11. Comparison of key factors in the CARB and EIA analyses, 2020

	CARB			EIA		
Projection	*Passenger cars and small light trucks*	*Heavy light trucks*	*Total*	*Passenger cars*	*Light trucks*	*Total*
CO_2 equivalent emission reductions						
Million metric tons	22.2	6.8	29.0	5.8	9.1	14.9
Percent of total	76.6	23.4	100.0	39.0	61.0	100.0
Distribution of light-duty vehicle stock (percent of total)	81.9	18.1	100.0	46.5	53.5	100.0
Distribution of light-duty vehicle miles traveled (percent of total)	82.1	17.9	100.0	47.4	52.6	100.0

A.B. 1493 standards relative to savings available under the CARB baseline assumption of no change in new vehicle fuel efficiency.

The third significant difference between the analyses is the projected impact of improved air conditioning systems on the reduction of CO_2 equivalent emissions. The CARB analysis includes CO_2 equivalent emission reductions associated with improved air conditioning. EIA's analysis assumes that manufacturers will use the maximum allowable air conditioning credits, but it does not explicitly model air conditioning systems or associated emissions. Analyses of the credits allowed for this technology indicate that approximately 4 to 7 percent of the total CO_2 equivalent emission reductions reported by CARB could be attributed to improved light vehicle air conditioning systems.

Regional Impacts on Transportation Fuel Supply and Prices

Relative to the *AEO2005* reference case, the A.B. 1493 California-only case projects reduced consumption of gasoline and diesel fuel in 2025 by 153,000 and 6,000 barrels per day, respectively, in Census Division 9 [*53*]. As a result, production of gasoline in 2025 is projected to decrease by 34,000 barrels per day, with an additional reduction of 109,000 barrels per day in gasoline imports. The balance of the difference results from changes in interregional transfers. Diesel fuel production in Census Division 9 is projected to decrease by 7,000 barrels per day in 2025. The reduction in diesel supply is slightly greater than the reduction in diesel consumption due to refinery optimization for gasoline production. As a result, disproportionate reductions in gasoline demand, as projected in the A.B. 1493 California-only case, affect the production of diesel even though the demand for diesel fuel is not projected to fall by as much.

A.B. 1493 has little projected impact on diesel prices in Census Division 9. Because the reduction in gasoline demand causes an almost equal reduction in supply in the A.B. 1493 California-only case, the average gasoline price for Census Division 9 between 2016 and 2025 is projected to be 0.6 cents per gallon lower, than projected in the *AEO2005* reference case.

The A.B. 1493 extended case, which applies the same light vehicle greenhouse gas reduction requirements to selected States in Census Divisions 1 and 2 in addition to California, projects reduced consumption of gasoline and diesel fuel in 2025, by 88,000 and 4,000 barrels per day, respectively, in the New England and Mid-Atlantic regions [*54*]. This demand reduction results in a similar reduction in gasoline imports to the two regions, although the projected reduction of 74,000 barrels per day in gasoline imports is less than the reduction in demand. In contrast to Census Division 9, Census Divisions 1 and 2 are traditionally more integrated to fuel supplies from other refining regions. As such, a reduction in gasoline consumption of 4.5 percent (or 88,000 barrels per day) in Census Divisions 1 and 2, relative to the *AEO2005* reference case, represents a reduction of only 0.9 percent when a broader market east of the Rocky Mountains including Census Divisions 1 through 7 (or Petroleum Administration for Defense Districts 1 through 3) is considered. The A.B. 1493 extended case has negligible impact on gasoline and diesel prices in Census Divisions 1 and 2.

Conclusion

Analysis of two A.B. 1493 cases indicates small national impacts on energy demand and fuel prices. The impact of A.B. 1493 could be more or less significant depending on manufacturer behavior, consumer response, and the number of States assumed to adopt the program if its legality is upheld. Because the required improvements in car fuel economy are much more stringent then those required for light trucks, above 3,750 pounds, a category that includes 88 percent of total light truck sales, consumer preference for larger high performance vehicles could spur further increases in the demand for light trucks, which counters the intent of the regulation. Further complicating the issue is the behavior of vehicle manufacturers with respect to their fiduciary responsibility to comply with nationally-based CAFE standards while also meeting niche market CO_2 emissions requirements. These issues, coupled with pending National Highway Traffic Safety Administration modifications to the current CAFE structure and the legal challenges facing A.B. 1493, create significant uncertainty with respect to the evaluation of the new California regulation.

Multi-Pollutant Legislation and Regulations

The 108th Congress proposed and debated a variety of bills addressing pollution control at electric power plants but did not pass any of them into law. In addition, the EPA currently is preparing two regulations—a proposed Clean Air Interstate Rule (pCAIR) and a Clean Air Mercury Rule (CAMR)—to address emissions from coal-fired power plants. Several States also have taken legislative actions to limit

pollutants from power plants in their jurisdictions. This section discusses three Congressional air pollution bills and the EPA's pCAIR and CAMR regulations.

Clear Skies Act of 2003, Clean Air Planning Act of 2003, and Clean Power Act of 2003

Several bills introduced in the 108th Congress proposed to regulate emissions of NO_x, sulfur dioxide (SO_2), mercury, and CO_2 from electric power plants. EIA received a request from Senator James M. Inhofe to conduct an analysis of S. 843, the Clean Air Planning Act of 2003, introduced by Senator Thomas Carper; S. 366, the Clean Power Act of 2003, introduced by Senator James Jeffords; and S. 1844, the Clear Skies Act of 2003, introduced by Senator Inhofe. The emissions targets and implementation timetables proposed in the bills are summarized in Table 12.

A report on the results of EIA's analysis [*55*] was released in May 2004. The analysis in the report was based on the assumptions used in *AEO2004*, which differed from those used in *AEO2005*. One of the most significant differences for the electricity sector is in projected natural gas prices. In *AEO2005*, the reference case projection for wellhead natural gas prices in 2025 is more than 30 cents higher than the *AEO2004* projection, primarily as a result of lower assumed finding rates (reserve additions per well) for onshore resources. The following summary of EIA's Inhofe-Carper-Jeffords analysis is based on the *AEO2004* projections.

To comply with the provisions of S. 1844, the Clear Skies Act (Inhofe), electricity producers would be expected to rely primarily on adding emissions control equipment to existing generators. Switching fuels from coal to natural gas and renewables would be expected to play a relatively small role. Producers would be expected to begin reducing mercury emissions before 2010 in order to take advantage of the early credit program included in S. 1844; however, emissions of mercury would remain above the 15-ton target in 2018, because the bill also specifies an "allowance price safety valve." Among the three bills analyzed by EIA, total costs to the electric power industry and projected impacts on electricity prices are lowest for S. 1844.

S. 843, the Clean Air Planning Act (Carper) would impose more stringent limits on emissions of SO_2, NO_x, and mercury than those proposed in S. 1844. In addition, S. 843 proposes a cap on CO_2 emissions. Emissions control equipment added to existing generators would also be expected to play an important role in compliance strategies under S. 843, but fuel switching from coal to natural gas and renewables would play a more important role. In addition, the impacts would be sensitive to the availability and cost of greenhouse gas offsets. Because of this uncertainty, two separate cases were included in EIA's analysis of S. 843—one (Carper domestic) assuming that only domestic offset programs would be approved and another (Carper international) assuming that both domestic and international offsets would be available. Overall, the resource costs and electricity price impacts under S. 843 were projected to be larger than those under S. 1844.

S. 366, the Clean Power Act (Jeffords), includes a more stringent cap on CO_2 emissions, which would be expected to make switching from coal to natural gas, renewables, and nuclear especially important in compliance strategies. S. 366 would require all older power plants to be retrofitted with emissions control

Table 12. Emissions targets in multi-pollutant legislation

Emissions	*S. 1844, Clear Skies Act (Inhofe)*	*S. 843, Clean Air Planning Act (Carper)*	*S. 366, Clean Power Act (Jeffords)*
NO_x	*2.19 million tons in 2008* *1.79 million tons in 2018*	*1.87 million tons in 2009* *1.7 million tons in 2013*	*1.51 million tons in 2009*
SO_2	*4.4 million tons in 2010* *3.0 million tons in 2018*	*4.5 million tons in 2009* *3.5 million tons in 2013* *2.25 million tons in 2016*	*2.25 million tons in 2009*
Mercury	*34 tons in 2010* *15 tons in 2018*	*24 tons in 2009* *10 tons in 2013*	*5 tons in 2008*
CO_2	*No cap*	*2,332 million metric tons CO_2 (636 million metric tons carbon equivalent) in 2009* *2,244 million metric tons CO_2 (612 million metric tons carbon equivalent) in 2013*	*1,863 million metric tons CO_2 (508 million metric tons carbon equivalent) in 2009*

equipment, even if emissions of SO_2, NO_x, and mercury fell below the respective aggregate reduction targets as a result of fuel switching. The early timing and stringency of the emissions limits, among other factors, would lead to the largest resource cost and electricity price impacts among the three bills. Because of the higher projected electricity prices under S. 366, consumers would also be expected to reduce their use of electricity.

Table 13 shows a summary of EIA's analysis results. Significantly, power plant emissions of NO_x in 2025 were projected to remain at about the levels of the respective phase 2 targets under S. 843 (1.7 million tons) and S. 1844 (1.79 million tons) shown in Table 12, because neither bill would be expected to provide significant opportunity for economical banking of NO_x allowances. Only under S. 366, which requires emissions controls at all plants over 40 years old, were NO_x emissions in 2025 projected to fall below the bill's emission target of 1.51 million tons shown in Table 12.

SO_2 emissions from electric power plants were projected to be reduced under the provisions of each of the three bills, as well as in the *AEO2004* reference case. Under S. 843 and S. 1844, however, SO_2 emissions in 2025 were projected to remain above the bills' target levels because of allowances banked from the existing SO_2 reduction program. Under S. 366, SO_2 emissions in 2025, like NO_x emissions, were projected to fall below the bill's target level.

Average retail electricity prices in 2025 were projected to be 3.2 percent higher under S. 1844 than in the *AEO2004* reference case forecast, and they were projected to be as much as 7.8 percent higher under S. 843 (Figure 9). Much larger price impacts were projected under S. 366—47 percent above reference case prices in 2010 and 27 percent above reference case prices in 2025—primarily because the proposed limit on CO_2 emissions at 1990 levels in 2009 would require rapid transformation of the Nation's power plant capacity from coal to natural gas, renewables, and nuclear fuel.

Proposed Clean Air Interstate Rule

The EPA's proposed CAIR [*56*] was published in the *Federal Register* [*57*] in January 2004 and in a supplemental notice [*58*] in June 2004. pCAIR is intended to reduce the atmospheric interstate transport of fine particulate matter ($PM_{2.5}$) and ozone. SO_2 and NO_x are precursors of $PM_{2.5}$. NO_x is also a precursor to the formation of ground-level ozone. pCAIR would require 29 States and the District of Columbia to develop plans to reduce SO_2 and/or NO_x emissions. The proposed rules would apply to all fossil-fuel-fired boilers and turbines serving electrical generators with capacity greater than 25 megawatts that provide electricity for sale. The proposed rules also would apply to combined heat and power (CHP) units that are larger than 25 megawatts, that sell at least one-third of their potential electrical output, and that meet certain operating and efficiency criteria. Table 14 shows the pCAIR emissions caps and timetables for meeting the caps.

Under pCAIR, the States would be responsible for allocating NO_x emissions allowances and taking the lead in pursuing enforcement actions, and they would have flexibility in choosing the sources to be controlled. They could meet the emissions reduction requirements either by joining the EPA-managed cap

Table 13. Key projections from EIA's 2004 analysis of proposed multi-pollutant control bills, 2025

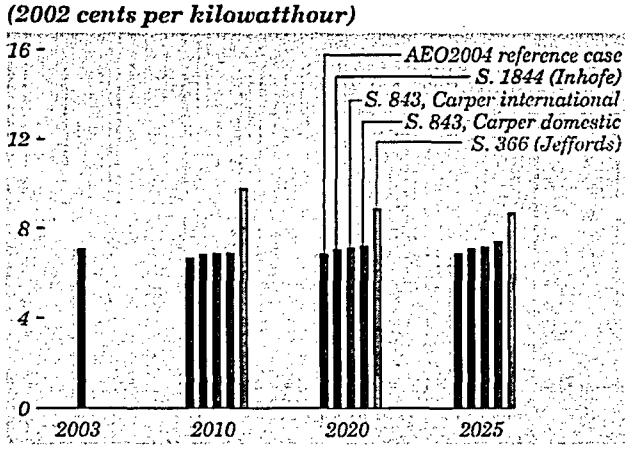
		2025				
				S. 843		
Projection	*2003*	*AEO2004 reference case*	*S. 1844*	*Carper international*	*Carper domestic*	*S. 366*
Total U.S. emissions						
NO_x (million tons)	4.1	3.7	1.8	1.7	1.7	0.61
SO_2 (million tons)	10.6	9.0	3.6	2.8	2.9	1.2
Mercury (tons)	49.7	54.6	29.0	10.0	10.0	3.7
CO_2 (million metric tons)	2,286	3,272	3,164	2,905	2,720	1,733
Electricity generation by fuel (billion kilowatthours)						
Coal	1,971	3,008	2,861	2,467	2,280	1,363
Nuclear	764	824	824	824	824	1,261
Natural gas	632	1,287	1,350	1,576	1,579	1,394
Renewables	350	537	597	758	930	1,310
Average retail electricity price (2002 cents per kilowatthour)	7.4	6.9	7.1	7.2	7.4	8.7

and trade programs for power plants, or by achieving reductions through emissions control measures on sources in other sectors (industrial, transportation, residential, or commercial), or on a combination of electricity generating units and sources in other sectors.

To participate in the cap and trade program, the States would be required to regulate power plant emissions within their boundaries. The EPA would be responsible for assigning State emissions budgets, reviewing and approving State plans, and administering the emissions and allowance tracking systems. State rules could allow sources currently subject to the CAAA90 Title IV rules and to the NO_x State Implementation Plan (SIP) Call trading program to use allowances banked from those programs before 2010 for compliance with pCAIR. pCAIR also would require additional reductions in NO_x emissions for States affected by the NO_x SIP Call.

The EPA plans to meet the SO_2 emission reduction requirements by implementing a progressively more stringent retirement ratio on SO_2 allowances for electricity generating units of different vintages under the CAAA90 Title IV acid rain program. New SO_2 allowances would not be issued under pCAIR; power plants would instead use the current pool of SO_2 allowances issued under Title IV. Allowances issued for vintage years 2004 through 2009 could be retired on a 1-to-1 basis, but allowances issued for vintage years 2010 through 2014 would have to be retired on a 2-to-1 basis, requiring 2 Title IV allowances to be retired for each ton of SO_2 emissions. Allowances issued for vintage years 2015 and later would be retired on a basis of approximately 2.9 to 1. This retirement procedure is proposed in order to integrate the pCAIR rules with the existing Title IV SO_2 emissions reduction program.

Figure 9. Projected electricity prices under proposed multi-pollutant control bills, 2010, 2020, and 2025 (2002 cents per kilowatthour)



NO_x emissions would be treated differently, with State emissions caps to be based on each State's share of region-wide heat input. In addition, new NO_x allowances would be issued, and banked SIP Call allowances could be traded under pCAIR.

pCAIR Analysis

Although the *AEO2005* reference case does not assume enactment of pCAIR, an alternative case has been developed to analyze its potential impacts. The pCAIR sensitivity case assumes the adoption of pCAIR emissions caps on SO_2 and NO_x and the proposed SO_2 allowance vintaging methodology. The caps are assumed to be imposed on all electricity generators and CHP units that sell electricity to the grid, and it is assumed that electricity producers would opt to participate in the EPA cap and trade program rather than relying on State emission reduction programs. Other than those assumptions, the pCAIR case uses the *AEO2005* reference case assumptions.

Table 15 compares the key results of the pCAIR case and the *AEO2005* reference case. In 2025, the pCAIR case results in a 46-percent reduction in national NO_x emissions from their 2003 level and a 63-percent reduction in SO_2 emissions from the 2003 level.

NO_x allowance prices are projected to increase in the pCAIR case. In the reference case, the NO_x SIP Call affects States primarily in the Northeast with a summer season NO_x cap. In the pCAIR case, the SIP Call caps are replaced by the pCAIR NO_x caps, which affect a different combination of States and are annual limits. Because the NO_x allowance prices under the two inherently different programs cannot be compared, Table 15 shows only the allowance prices under pCAIR.

SO_2 allowance prices are projected to be significantly higher in the pCAIR case than in the reference case, which assumes continuation of the currently enacted

Table 14. Historical emissions and proposed future caps for the combination of affected pCAIR States (million tons)

Emissions	Emissions in 2002	Emissions cap in 2010	Emissions cap in 2015
NO_x	3.78	1.60	1.33
SO_2	9.39	3.86	2.71

CAAA90 allowance program. The higher SO_2 allowance prices in the pCAIR case reflect the need for utilities to reduce emissions to lower levels than currently required under CAAA90.

One of the key results of the pCAIR case is that electric power producers would be required to install significantly more pollution control equipment than in the reference case. To comply with the pCAIR limits in SO_2 emissions, electricity producers are projected to install flue gas desulfurization (FGD) scrubbers on nearly 100 gigawatts more coal-fired capacity than in the reference case through 2025. Similarly, to meet the pCAIR NO_x limits, SCR equipment is projected to be installed on about 60 gigawatts more coal-fired capacity than in the reference case. In the reference case, total coal-fired capacity in the United States is projected to grow from 314 gigawatts in 2003 to 398 gigawatts in 2025. Thus, in the pCAIR case, roughly one-third of all coal-fired power plants would be retrofitted with FGD and SCR equipment by 2025. The pCAIR case does not project a significant change in the fuel mix for electricity generation in 2025 relative to that in the reference case, showing only a slight reduction in coal use, a small increase in natural gas use, and a small increase in renewable fuel use (Figure 10).

Only modest changes in regional coal production are projected in the pCAIR case (Figure 11). In both the reference and pCAIR cases, coal production increases from 2003 to 2025. Relative to the reference case, the pCAIR case projects a decrease in Appalachian coal production of about 2 percent in 2025, a decrease in Interior coal production of about 13 percent (24 million tons), and an increase in Western coal production of about 1.1 percent, based on the generally lower sulfur content of Western than Appalachian and Interior coal resources.

After the first phase of the pCAIR emissions caps begins to take effect in 2010, average U.S. retail electricity prices are projected to be higher by a maximum of 2.3 percent in the pCAIR case than in the reference case, with a similar difference in projected resource costs for the electric power sector (the amount that power companies spend on fuel, capital, and operations and maintenance). Projected resource costs

Table 15. Key electricity sector projections from EIA's analysis of proposed pCAIR regulations, 2015 and 2025

		2015		2025	
Projection	*2003*	*AEO2005 reference case*	*pCAIR case*	*AEO2005 reference case*	*pCAIR case*
Total U.S. emissions					
NO_x (million tons)	4.1	4.1	2.1	4.3	2.2
SO_2 (million tons)	10.6	9.0	4.7	9.0	3.9
Allowance prices (2003 dollars per ton)					
NO_x	—	—	2,524	—	2,789
SO_2	172	290	1,160	247	1,463
Coal-fired capacity retrofits (gigawatts)					
Flue gas desulfurization	0	26	107	27	128
Selective catalytic reduction	0	70	131	74	133

Figure 10. Projected electricity generation by fuel in two cases, 2025 (billion kilowatthours)

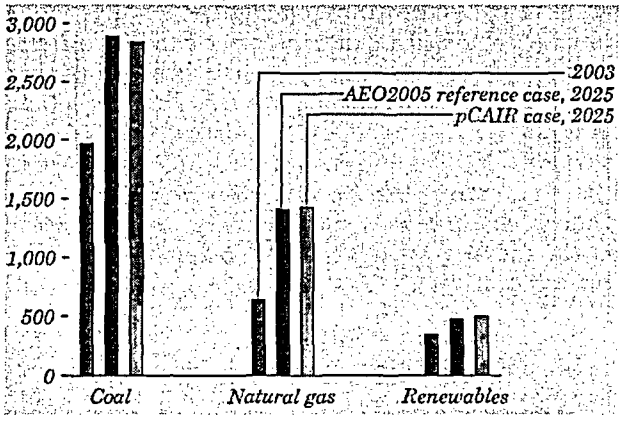
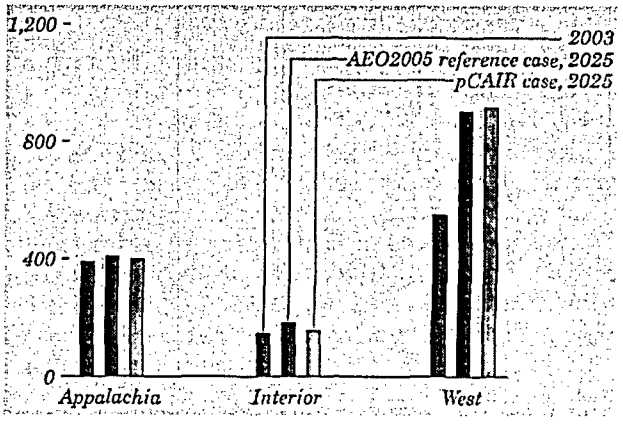


Figure 11. Projected coal production by region in two cases, 2025 (million tons)



from 2010 through 2025 are higher by a maximum of $3.5 billion per year (about 2.5 percent) in the pCAIR case than in the *AEO2005* reference case.

Proposed Clean Air Mercury Rule

The EPA's CAMR (proposed as the Utility Mercury Reductions Rule) [*59*] for controlling mercury emissions from new and existing coal-fired power plants was published in the *Federal Register* [*60*] in January 2004 and in a supplemental notice [*61*] in March 2004. Nickel emissions from new and existing oil-fired power plants would also be capped under the proposed rule; however, as of 2002 only 2.3 percent of the electricity generated in the United States was from oil-fired units, and 50.2 percent was from coal-fired units [*62*]. Therefore, the focus in this section is on the proposed regulations applicable to coal-fired units. Power plants with capacity greater than 25 megawatts and CHP units that are larger than 25 megawatts and sell at least one-third of their electricity would be subject to CAMR.

The EPA estimates that CAMR, using a cap and trade approach, would reduce mercury emissions by nearly 70 percent when fully implemented. Two alternative approaches were proposed for reducing mercury emissions. The first, which would require the installation of MACT under CAAA90 Section 112, would reduce annual emissions from the electricity generation sector by about 29 percent, from 48 tons in 2002 to 34 tons in 2008. The second approach would modify Section 112 to allow regulation of mercury emissions under a cap and trade program. The program would be implemented in two phases, with a banking provision that would allow for reductions as early as 2010 and a second phase that would set a cap of 15 tons in 2018.

Under the cap and trade approach, States would submit plans to the EPA to demonstrate that they would meet their assigned State-wide mercury emissions budgets. With EPA approval, the States could then participate in the cap and trade program. Allowances would be allocated by the States to power companies, which could either sell or bank any excess allowances. The EPA proposed a safety valve price of $2,187.50 per ounce of mercury ($35,000 per pound), adjusted annually for inflation. The price of allowances would effectively be capped at that level, and power plant operators could buy allowances at any time at the safety valve price, reducing the State's budget in the future. Public comments on CAMR have been received, and the EPA expects to issue the final rules in March 2005.

Climate Stewardship Act of 2004

Senators John McCain and Joseph I. Lieberman introduced the Climate Stewardship Act of 2003 (S. 139) in the U.S. Senate in 2003. S. 139 would establish regulations to limit U.S. emissions of greenhouse gases [*63*], primarily through a program of tradable emission allowances and related emissions reporting requirements. In October 2003, Senators McCain and Lieberman proposed an amended version of the bill, S.A. 2028, which included the first phase of emissions reductions beginning in 2010 as proposed in S. 139 but removed references to a second phase of reductions beginning in 2016. On October 30, 2003, the Senate voted 43-55 to reject the measure. In July 2004, the Senators submitted the bill as the Climate Stewardship Act of 2004 (S.A. 3546), intending it as an amendment to legislation on class action lawsuits (S. 2062); however, the proposed amendment was tabled. Senator McCain has stated his intention to continue resubmitting the Climate Stewardship Act until it is passed by the Senate.

In March 2004, Representative Wayne Gilchrest submitted a version of the same bill, also called the Climate Stewardship Act of 2004, in the U.S. House of Representatives (H.R. 4067). It was cosponsored by 70 other Representatives. The House bill is essentially the same as the most recent Senate version, S.A. 3546. H.R. 4067 has been referred to the House Science Committee and Energy and Commerce Committee.

Overview

The Climate Stewardship Act of 2004 [*64*] would establish a system of tradable allowances to reduce greenhouse gas emissions. The bill includes requirements for mandatory emissions reporting by covered entities and for voluntary reporting of emissions reduction activities by noncovered entities; a national greenhouse gas database and registry of reductions; and a research program on climate change and related activities. The emissions allowance program would apply to most greenhouse gas emissions sources, the exceptions being those in the residential sector and entities in all sectors whose annual emissions are less than a certain threshold. Entities not directly covered by the allowance program would nevertheless be affected by its impacts on energy prices and the economy as a whole, as well as by the program's incentives to reward voluntary reductions of emissions.

The bill defines the covered sectors for the emission allowance program as the commercial, industrial,

electric power, and transportation sectors [*65*]. Covered entities in the commercial, industrial, and electricity sectors are those that emit, from any single facility, greenhouse gas emissions from stationary sources exceeding 10,000 metric tons carbon dioxide equivalent per year [*66*]. In effect, this threshold would exempt most entities in the agriculture and commercial sectors. All petroleum used for transportation within the United States would be covered, and refiners would be responsible for submitting allowances for emissions related to petroleum sold for transportation use. Producers and importers of hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride would be required to submit allowances for emissions associated with their products, subject to the 10,000 metric ton threshold.

The bill provides for the exemption of emission sources if the EPA deems their measurement or estimation to be impractical. This exemption would most likely apply to a large share of U.S. nitrous oxide and methane emissions, because many of their sources are difficult or uneconomical to measure.

Emission Allowance Program

The market-driven system of emission allowances proposed in the Climate Stewardship Act of 2004 would control greenhouse gas emissions by creating a fixed number of tradable emission allowances each year. The EPA is charged with establishing the regulations to create the tradable allowances, and the bill defines many of the provisions governing the allowances. The bill would provide entities with options for banking and borrowing allowances; for limited use of registered reductions from noncovered entities in lieu of allowances [*67*]; and for obtaining allowance allocation credits to reward past emissions reductions and early action reductions. The bill would establish a nonprofit Climate Change Credit Corporation (CCCC) to facilitate the market in emission allowances, to buy and sell allowances, and to distribute proceeds from sales to mitigate the economic impacts of the program. The Secretary of Commerce would be responsible for allocating allowances to the covered sectors and to the CCCC, subject to the final approval of Congress.

Each emission allowance would provide the right for an entity to emit one ton of greenhouse gases, measured in carbon dioxide equivalent units based on 100-year global warming potential. The number of allowances created each year would effectively establish a cap on total U.S. emissions; however, with the banking of allowances for future use permitted under the bill, emissions in any year could differ from the number of allowances issued [*68*]. The bill would require individual covered entities to submit allowances equal to their emissions but would not otherwise limit their emissions. An entity's emission allowance obligation would be based on its reported annual emissions, mandated under the program. The bill calls for the future development of emissions measurement and verification procedures that could be used to audit an entity's allowance obligation. Entities would be able to buy and sell allowances and to bank allowances for future use. Under limited conditions, covered entities could borrow against future emissions reductions [*69*].

Emission Caps

The bill specifies emission allowance caps based on aggregate emissions for the covered sectors in 2000, excluding emissions from the residential sector, the agriculture sector, and U.S. territories [*70*]. The bill specifies the total number of annual allowances at 5,896 million metric tons carbon dioxide equivalent, adding the phrase "reduced by the amount of emissions of greenhouse gases in calendar year 2000 from noncovered entities." This wording leaves the level of allowances that establishes the cap open to interpretation and questions of emissions accounting. Noncovered entities are those that have no facilities with annual emissions above 10,000 metric tons carbon dioxide equivalent; neither the identification of those entities nor their aggregate level of emissions in 2000 is known precisely. Because noncovered entities would not be required to report emissions, their emissions could be estimated only by subtracting covered entities' reported emissions from estimates of total emissions. Noncovered emissions would also include emissions from sources the EPA deemed impractical to measure. Under these definitions, the level of emissions from noncovered sources would be unknown, and the number of allowances to be created after adjusting for noncovered emissions is uncertain.

In a June 2003 analysis of S. 139 [*71*], EIA estimated that approximately 75 percent of total U.S. greenhouse gas emissions would be covered under the bill. The impact of the bill on total emissions would depend on growth in noncovered emissions and how covered entities made use of alternative compliance provisions, such as registered increases in carbon sequestration.

Allowance Allocation, Allowance Banking, and Alternative Compliance Provisions

The allocation of emission allowances to covered sectors and entities is not completely fixed by the bill. Some of the Government-issued allowances would be distributed directly to covered entities, and the rest would go to the CCCC. A number of criteria for allocating emissions allowances are defined in the bill, but neither the total percentage of allowances to be distributed free nor the share to be distributed to each of the covered sectors is specified. The bill does, however, describe an allocation procedure to reward entities for registered emissions reductions made since 1990 and reductions made in advance of the 2010 start date. Entities with creditable reductions would be granted a corresponding increase in their future allocations of allowances for the compliance period beginning in 2010. Credits for early action would not affect the overall compliance cap, only the allocation of free allowances to covered entities. Nevertheless, this provision would provide an incentive to reduce emissions early in exchange for future allowance allocations.

The bill's allowance trading and alternative compliance provisions would result in markets for emission allowances and registered offset credits. The market for allowances and related incentives should result in a market-clearing price for allowances that would reflect both the cost of reducing emissions and the flexibility of allowance banking. Because allowances could be sold or held for future use, covered entities would have an incentive to reduce emissions under the bill, even if they were allocated sufficient allowances to cover their annual emissions. Some entities would find it economical to over-comply and sell or bank emission allowances, depending on the cost of emissions reduction opportunities, future expansion plans, and expectations about future allowance prices.

A market for the alternative compliance emission credits, or offsets, would also provide economic incentives for noncovered entities to reduce emissions and register their reductions. The bill would allow covered entities to submit such registered credits in place of up to 15 percent of their allowance obligations. Offsets could be registered by domestic sources as well as from other countries that have greenhouse gas emissions limits and comparable allowance trading provisions in place. The allowance offsets could also come from increases in biological carbon sequestration, such as through reforestation, and to a limited extent from changes in agricultural practices to increase net carbon sequestration in the soil [72]. Offsets would likely sell at or below the price for allowances. Suppliers competing to meet the limited demand for offsets could bid down the offset price to a level below the allowance price.

Energy Market Impacts

Energy consumers would incur higher effective costs of using energy as a result of the bill's allowance program. In the transportation sector, end-use consumers would face higher delivered prices of refined products when refiners passed on the cost of allowances required for emissions of petroleum-based fuels sold for transportation [73]. Covered entities in the commercial, industrial, and electric power sectors would implicitly face a higher cost of consuming fossil energy, because they would be required to obtain allowances for carbon dioxide emitted in direct fuel use. To the extent that electricity generators could pass through the opportunity cost of allowances and related incremental capital costs to their customers, electricity prices would increase in all consuming sectors. The increased energy costs, whether incorporated in delivered prices or reflected implicitly as opportunity costs of consuming energy, would affect all energy sectors of the economy.

The energy cost impacts on consumers and businesses could be substantially reduced by actions of the CCCC, which would be tasked to use proceeds from allowance sales to diminish the economic impact of the program. The extent to which the CCCC could funnel allowance proceeds back into the economy would depend on the allocation of allowances it received. The bill leaves the allocation of available allowances between the CCCC and covered entities unspecified. The CCCC share of allowances would be determined on an annual basis by the Secretary of Commerce, subject to approval by the Congress.

The funds collected by the CCCC could be dispersed to energy consumers by various methods, including cash rebates, rebates for energy-efficient appliances, subsidies, and general transition assistance to displaced workers. The bill specifies that the CCCC must allocate a percentage of the proceeds from allowances to provide transition assistance to dislocated workers and communities; however, the transition assistance amount probably would be a small fraction of the total allowance proceeds collected. The remaining proceeds would be returned to the economy, possibly as rebates. As a result, the bill has the potential to compensate consumers to some extent for higher direct energy costs and the indirect impacts of higher prices for non-energy goods and services.

Issues in Focus

Introduction

This section of the *Annual Energy Outlook* provides in-depth discussions of topics related to specific assumptions underlying the reference case forecast. In particular, the discussions focus on new methods or data that have led to significant changes in modeling approaches for the reference case. In addition, this section provides a more detailed examination of alternative cases.

World Oil Price Cases

World oil prices in *AEO2005* are set in an environment where the members of OPEC are assumed to act as the dominant producers, with lower production costs than other supply regions or countries. Non-OPEC oil producers are assumed to behave competitively, producing as much oil as they can profitability extract at the market price for oil. As a result, the OPEC member countries will be able effectively to set the price of oil when they can act in concert by varying their aggregate production. Alternatively, OPEC members could target a fixed level of production and let the world market determine the price.

The behavior and ability of OPEC member countries to set the price of oil will be influenced by many factors about which there is considerable uncertainty. These factors include the forces that will drive world oil demand, such as the rate of economic growth in the developed and developing world and the degree to which oil demand is linked to economic growth. The behavior of each major non-OPEC producer and changes in technologies that use or find and extract oil also will be important. Each of these factors will also be influenced by the market strategy that the OPEC members choose for OPEC in the aggregate or for themselves. For example, a strategy targeting relatively low prices and high market share would reduce the risk that new oil conservation or development technologies might be developed. It also would reduce the incentive for individual OPEC members to exceed their output quotas and reduce the risk that world economic growth might be slowed. With such a strategy, OPEC members would face little risk of losing market power, but their revenues and profits would be relatively low.

Conversely, if OPEC members jointly limited production to maintain high prices and low market share, new oil conservation or exploration and production technologies might be developed. Such a strategy would also increase the incentive for individual OPEC members to exceed their output quotas, cause importing countries to enact oil consumption reduction policies, and increase the likelihood that world economic growth would be slowed. While this strategy could result in relatively high revenues and profits in the short term, it would also be a relatively high-risk strategy.

> ***World Oil Prices in AEO2005***
>
> World oil prices in *AEO2005* are defined on the basis of "average refiner acquisition cost" of imported oil to the United States (IRAC). The IRAC price tends to be a few dollars less than the widely cited West Texas Intermediate (WTI) spot price, and in recent months it has been as much as 6 dollars a barrel lower than the WTI. For the first 11 months of 2004, WTI averaged $41.31 per barrel and IRAC averaged $36.28 per barrel (in nominal dollars).

Approach

The *AEO* develops world oil price scenarios through an iterative process that examines the reasonableness of candidate oil price paths and their impacts on world oil supply and demand. The *AEO* process also considers the stated OPEC basket price target range, as well as ongoing discussions among OPEC members regarding possible changes to it.

The *AEO2005* reference case assumes a moderate market strategy between low-price, low-risk market share maximization and high-price, high-risk profit maximization. Alternative cases, in which different oil market behaviors are assumed, are also considered in *AEO2005*, including the October oil futures case, high A and B world oil price cases, and a low world oil price case. As with all of the projections in *AEO2005*, the oil price forecasts do not represent an assessment of what will happen, but rather, an assessment of what might happen under various scenarios. Higher or lower price paths are possible, and short-term price volatility in oil markets, which *AEO* scenarios do not attempt to model, is likely to continue.

World Oil Demand. Key inputs for projecting world oil demand—for example, the worldwide demand for various energy services (heating, cooling, transportation, etc.)—are estimated using EIA's System for Analysis of Global Energy Markets (SAGE) [*74*]. SAGE is an integrated set of regional models that provides a technology-rich basis for estimating regional energy supply and demand. For each region, estimates of end-use energy service demands (e.g., car, commercial truck, and heavy truck road travel; residential lighting; steam heat requirements in the paper industry; etc.) are developed on the basis of

economic and demographic projections. Projections of energy demand are estimated on the basis of each region's existing energy use patterns, the existing stock of energy-using equipment, and the characteristics of available new technologies, as well as new sources of primary energy supply.

While oil products are used for many energy services (i.e., heating, steam generation, electricity generation, etc.) and as industrial feedstocks, the major use of petroleum products is for transportation. As a result, the worldwide demand for transportation services is the key driver for oil demand. In turn, the demand for transportation services in the various regions and countries represented in SAGE is driven by the projected level of income per capita, complemented by other important region-specific factors, such as the state of the transportation infrastructure. For the industrialized countries with well-developed transportation networks, demand for transportation services is influenced primarily by projected income levels and lifestyles; for developing countries, the lack of transportation infrastructure can be a significant constraint.

Table 16 summarizes by region and country the projected average annual growth rates for real GDP and oil demand, and the resulting oil intensity, in the *AEO2005* reference case from 2003 to 2025 [*75*]. The table also shows region and country shares of world GDP and oil demand in 2003 and 2025. As shown, total world GDP is projected to grow at an average annual rate of 3.1 percent, with the developing and former Soviet Union (FSU) countries generally projected to grow at higher rates, while the industrialized countries generally grow at slower rates. Total world oil demand is projected to grow more slowly, at 1.9 percent annually. World oil intensity declines by 1.2 percent per year.

Because of the differences in projected growth rates for GDP and oil demand, the developing countries are expected to play a growing role in the world economy and oil markets. In 2003, the industrialized countries accounted for 77 percent of world GDP and 57 percent of total world oil consumption. It is projected that in 2025 real GDP in industrialized countries will account for 68 percent of world GDP and 48 percent of total oil demand. In contrast, developing countries are projected to account for 28 percent of world GDP in 2025, up from 20 percent in 2003. Similarly, oil demand in developing countries is projected to account for 45 percent of world oil demand in 2025, up from 36 percent in 2003.

Table 16. Projected growth in world gross domestic product, oil consumption, and oil intensity in the AEO2005 reference case, 2003-2025

	Real GDP			Oil consumption			Oil intensity		
	Percent of world GDP		Annual growth, 2003-2025 (percent)	Percent of world oil use		Annual growth, 2003-2025 (percent)	Oil use (thousand Btu) per 1997 U.S. dollar of GDP		Annual growth, 2003-2025 (percent)
Country/region	2003	2025		2003	2025		2003	2025	
Industrialized countries									
United States	29.3	29.3	3.1	25.6	23.6	1.5	4.0	2.9	-1.5
Canada	2.3	2.2	2.7	2.7	2.3	1.2	5.3	3.8	-1.5
Mexico	1.4	1.7	4.1	2.5	2.9	2.5	8.3	5.9	-1.5
Western Europe	28.6	23.3	2.1	17.9	13.0	0.5	2.9	2.0	-1.7
Japan	13.4	9.9	1.7	7.0	4.8	0.2	2.4	1.7	-1.5
Australia/New Zealand	1.7	1.7	3.0	1.3	1.4	2.2	3.5	3.0	-0.7
Total	76.8	68.2	2.5	57.0	48.1	1.1	3.4	2.5	-1.4
Former Soviet Union and Eastern Europe									
Former Soviet Union	2.1	2.6	4.1	5.2	5.4	2.0	11.5	7.3	-2.0
Eastern Europe	1.2	1.5	4.0	1.8	1.7	1.8	6.7	4.2	-2.1
Total	3.3	4.1	4.1	7.0	7.1	1.9	9.7	6.2	-2.0
Developing Countries									
China	4.1	7.5	5.9	7.0	10.6	3.9	7.7	5.0	-1.9
India	1.7	2.7	5.2	2.8	4.4	4.1	7.4	5.9	-1.1
South Korea	1.8	2.3	4.2	2.7	2.4	1.4	6.9	3.8	-2.7
Other Asia	4.0	5.3	4.4	7.2	8.8	2.9	8.3	6.0	-1.5
Middle East	1.9	2.1	3.7	7.0	7.5	2.2	17.3	12.7	-1.4
Africa	2.0	2.4	4.1	3.4	3.9	2.5	7.9	5.7	-1.5
South/Central America	4.5	5.5	4.1	5.9	7.1	2.8	6.0	4.6	-1.2
Total	19.9	27.8	4.7	36.0	44.8	2.9	8.3	5.7	-1.7
Total World	100.0	100.0	3.1	100.0	100.0	1.9	4.6	3.5	-1.2

The projected growing role of the developing countries in the world economy and oil markets makes understanding the impact of economic growth on oil demand critically important. The sensitivity of oil demand to income is often characterized by what economists refer to as the income elasticity of demand, defined as the percentage change in oil demand with respect to the percentage change in real income. A rough approximation of the relative sizes of income elasticities for the different countries and regions represented in SAGE can be calculated from Table 16 by dividing the 2003 to 2025 average annual growth in oil demand by the average annual growth in real GDP. This calculation yields an income elasticity of demand of approximately 0.6 for the developing countries, compared with 0.4 for the industrialized countries [*76*].

The implication that oil demand in developing countries will be more responsive to changes in economic and income growth is consistent with research, but there is a great deal of uncertainty about the level of response. The response of oil demand to income growth and changes in oil prices has been examined in a number of empirical studies. The estimates of income elasticities in those studies vary widely, depending on the time period under study, the groups of countries considered, and the econometric specifications used [*77*]. Although the empirical evidence is not conclusive, and the magnitude of income elasticity estimates varies widely, most studies have found that developing countries generally have higher income elasticities than the industrialized economies.

Studies have shown both greater and smaller responses in developing countries than is reflected in SAGE. For example, Gately and Huntington found that the income elasticity of demand for oil in developing countries ranged from 0.5 to 1.0, depending on the groups of developing countries being considered [*78*]. The Gately and Huntington study, as well as most other empirical studies, used historical data and employed a single-equation reduced-form framework relating oil demand changes to changes in income, or income per capita, and oil prices in various lag formulations.

Such formulations may not fully capture the changes that have occurred in world economies or technologies in recent years, nor reflect how these changes might affect the future. For example, in an era of increased globalization and rapid technology transfer across countries, empirical estimates derived from historical data and simplified model formulations may not fully capture the more rapid transfer of new, efficient technologies from the industrialized countries to the developing countries that is likely to occur in the future. In contrast, the inferred income elasticities approximated in this report are based on projections coming from a structural model that explicitly incorporates the technical and cost relationships projected to exist between energy service demands by end-use sectors and the supply of energy. The model also represents region-specific factors that may encourage or inhibit demand for oil, such as transportation infrastructure constraints that are likely to arise as developing economies grow. One key assumption is that vehicles sold in both developing and industrialized countries in the future will be more fuel efficient than they were in the past.

World Oil Supply. Once oil demand has been estimated by region and country, the levels of regional non-OPEC conventional and nonconventional oil production are developed to be consistent with the assumed world oil price path and assumptions regarding proved oil reserves, undiscovered oil, and reserve growth. The gap between projected world oil consumption and non-OPEC oil production determines the call on OPEC producers. Production from individual OPEC suppliers is estimated based on information regarding proved reserves, project development schedules, long-term development plans, and production economics in each country or region. Production capacity estimates reflect both projected levels of supply and historical utilization rates. Several Persian Gulf OPEC producers, including Saudi Arabia, Kuwait, and the United Arab Emirates, are assumed to have production capacity utilization rates of 90 to 95 percent, while non-OPEC producers are assumed to use all of their capacity. Other OPEC producers are assumed to fall between these extremes.

The growth in non-OPEC oil supplies has played a significant role in the erosion of OPEC's market share over the past three decades, as non-OPEC supply has become increasingly diverse. North America dominated growth in non-OPEC supply in the early 1970s, the North Sea and Mexico evolved as major producers in the 1980s, and much of the new production since the 1990s has come from Latin America, West Africa, and the former Soviet Union. Non-OPEC supply from proved reserves is expected to increase steadily from 48.8 million barrels per day in 2003 to 65.0 million barrels per day in 2025 in the reference case.

The expectation in the late 1980s and early 1990s was that non-OPEC production in the longer term would stagnate or decline gradually in response to resource

constraints. The relatively low cost of developing oil resources in OPEC countries (especially those in the Persian Gulf region) was considered such an overwhelming advantage that non-OPEC production potential was viewed with considerable pessimism. In actuality, however, despite several periods of relatively low prices, non-OPEC production has risen every year since 1993, growing by more than 8.2 million barrels per day between 1993 and 2003. Three factors are generally given credit for the impressive resiliency of non-OPEC production: development of new exploration and production technologies, efforts by the oil industry to reduce costs, and efforts by governments in non-OPEC countries to promote exploration and development by encouraging outside investors with attractive financial terms.

It is expected that oil prices will remain high enough that non-OPEC producers will be able to continue to increase output profitably, producing an additional 6.8 million barrels per day by 2010 in the reference case when compared with 2003. Much of the increased non-OPEC production is expected to come from Africa and Central and South America.

No one doubts that fossil fuels are subject to depletion and that depletion leads to scarcity, which in turn leads to higher prices; however, there are many resources that are not heavily exploited because they cannot be produced economically at low prices and with existing technologies. With higher prices, the development of such resources could become profitable. Ultimately, a combination of escalating prices and technological enhancements can make more resources economical. Much of the pessimism about oil resources has been focused entirely on conventional resources. However, there are substantial nonconventional resources, including production from oil sands, ultra-heavy oils, gas-to-liquids technologies, coal-to-liquids technologies, biofuel technologies, and shale oil, which can serve as a buffer against prolonged periods of very high oil prices. Total nonconventional liquids production in 2025 is projected to be 5.7 million barrels per day in the reference case, up from 1.8 million barrels per day in 2003.

Comparison of Projections

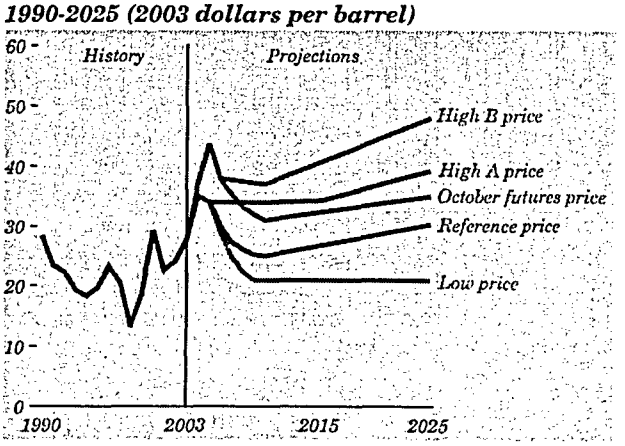
The world oil price cases in *AEO2005* are designed to address the uncertainty about the market behavior of OPEC. They are not intended to span the full range of possible outcomes. The cases are defined as follows:

- *Reference case.* Prices in 2010 are projected to be about $10 per barrel lower than current prices (2003 dollars) as both OPEC and non-OPEC producers add new production capacity over the next 5 years. After 2010, oil prices are projected to rise by about 1.3 percent per year, to more than $30 per barrel in 2025.
- *October oil futures case.* Prices in the near term rise through 2005, and then resume a growth trend similar to the reference case. The results of this case, which are similar to the reference case in the long term, are compared with the reference case results in the text box on page 44.
- *High A world oil price case.* Prices are projected to remain at about $34 per barrel through 2015 and then increase on average by 1.4 percent per year, to more than $39 per barrel in 2025.
- *High B world oil price case.* Projected prices continue to increase through 2005 to $44 per barrel, fall to $37 in 2010, and rise to $48 per barrel in 2025.
- *Low world oil price case.* Prices are projected to decline from their high in 2004 to $21 per barrel in 2009 and to remain at that level out to 2025.

World oil price projections in the five cases are shown in Figure 12. A detailed tabular summary and comparison of each of the oil price cases with the reference case is provided in Appendixes C and D.

Reference World Oil Price Case. In the reference case, the assumption is that the OPEC members will continue to demonstrate a disciplined production approach that reflects a strategy of price defense in which the larger producers are willing to increase or decrease production levels to maintain fairly stable prices (in real dollar terms) to discourage the development of alternative crude oil supplies or energy

Figure 12. World oil prices in the reference, October oil futures, high A, high B, and low oil price cases, 1990-2025 (2003 dollars per barrel)



The October oil futures case

The *AEO2005* reference case assumes that world crude oil prices will decline as consumption slows and producers increase their productive capacity and output in response to current prices. In October 2004, however, NYMEX oil futures prices implied that the average annual oil price in 2005 will exceed its 2004 level before falling back somewhat, to levels that still would be above those projected in the reference case. To evaluate the likely effects of that possible price path on the U.S. energy economy, *AEO2005* includes an October oil futures case, which is based on an extrapolation of oil prices loosely corresponding to the recent mid-term profile of prices on the NYMEX futures market.

In the October oil futures case, world crude oil prices are assumed to average $44 per barrel in 2005 (in 2003 dollars) before falling to about $31 per barrel in 2010—about $6 per barrel higher than the reference case projection. Prices are assumed to remain above those in the reference case over the entire projection and to be about $5 per barrel higher than the reference case projection in 2025, at $35 per barrel.

The *AEO2005* reference case and October oil futures case are based on different assumptions about oil production by the members of OPEC—higher in the reference case and lower in the October oil futures case—reflecting uncertainty about future levels of production from the Persian Gulf region. OPEC members are assumed to be the principal source of the marginal supply needed to meet increases in demand; consequently, OPEC member country production varies more than non-OPEC production in response to changes in demand requirements. OPEC member country production in 2025 is projected to be about 55 million barrels per day in the reference case and about 50 million barrels per day in the October oil futures case.

U.S. domestic consumption of petroleum in 2025 is projected to be slightly lower in the October oil futures case than in the reference case (27.3 million and 27.9 million barrels per day, respectively). Most of the difference is the result of lower projected demand for transportation fuels in the October oil futures case. In 2025, total demand for petroleum in the U.S. transportation sector is projected to be 19.5 million barrels per day in the October oil futures case, compared with 19.8 million barrels per day in the reference case.

Higher oil prices in the October oil futures case are projected to have a small impact on U.S. economic activity, primarily in the first 5 years of the forecast. From 2005 to 2010, U.S. GDP is a cumulative $194 billion (about 0.3 percent) lower in the October oil futures case than in the reference case. By 2025, however, the GDP projections are nearly identical in the reference and October oil futures cases. The projections for electricity and natural gas prices are not appreciably different in the two cases, which differ primarily in their projections for the delivered price of petroleum products, with impacts mainly in the transportation sector.

In response to higher oil prices, total domestic petroleum supply in 2025 is projected to be higher in the October oil futures case (9.3 million barrels per day) than in the reference case (8.8 million barrels per day), which in combination with the lower demand projection leads to a lower projected level of total petroleum imports in the October oil futures case. Including crude oil and refined products, total net imports in the October oil futures case (18.0 million barrels per day) are 1.1 million barrels per day lower than in the reference case (19.1 million barrels per day in 2025). As a result, the import share of total U.S. petroleum demand is 66 percent in the October oil futures case, compared with 68 percent in the reference case. In 2003, the import share of U.S. demand was 56 percent.

In the U.S. energy market, the transportation sector consumes about two-thirds of all petroleum products and the industrial sector about one-quarter. The remaining 10 percent is divided among the residential, commercial, and electric power sectors. With limited opportunities for fuel switching in the transportation and industrial sectors, large price-induced changes in U.S. petroleum consumption are unlikely, unless changes in petroleum prices are very large or there are significant changes in the efficiencies of petroleum-using equipment. The results of the October oil futures case indicate that sustained increases in world oil prices would have to be significantly greater than those assumed for this case in order to have a major impact on projected U.S. energy use.

sources, allow for continued robust worldwide economic growth, and maintain compliance with quotas, particularly by smaller OPEC producers. It is also assumed that OPEC producers will achieve sufficient oil revenues to expand production capacity enough to keep prices in a range of $27 to $30 per barrel in 2003 dollars, near the high end of the current OPEC price target range. Their current level of proven reserves (870 billion barrels) is sufficient to meet the implied production levels.

In the medium term, there is enough resource potential in non-OPEC countries to allow non-OPEC oil production to continue growing. Over the longer term, it is estimated that it will be harder for non-OPEC producers to continue to increase production. Assuming reference case prices, the search for alternatives and unconventional liquids will be limited, while demand will continue to grow. Therefore, OPEC members will have to make up the production difference (Figure 13). To satisfy the remaining global demand for oil at the given reference case prices, OPEC production will have to increase from 30.6 million barrels per day to 55.1 million barrels per day, an average annual increase in production of 2.7 percent. This is projected to result in an increase in OPEC's market share from 39 percent in 2003 to 46 percent in 2025, as cheaper sources of non-OPEC oil are depleted.

Table 17 summarizes the main features of the reference case in terms of cumulative production volumes, cumulative revenues, and the sum of the discounted cumulative revenues (at a 5-percent discount rate) from 2003 to 2025 [79]. The OPEC and non-OPEC countries are aggregated by major regions.

The reasoning behind the assumed prices and production patterns in the reference case can be questioned. If OPEC members have sufficient market power and cohesiveness to set world prices, why would they not try to set higher oil prices? If OPEC comprised a group of producer countries with similar oil reserves, resource depletion time horizons, geopolitical concerns, and no fear of alternatives to oil at higher prices, then a more limited production strategy that maximizes economic profits in the short to medium term would appear more plausible. In the absence of these conditions, however, and given the difficulty of enforcing tight production goals to limit output, a reasonable strategy is to maintain stable prices that discourage oil alternatives while limiting the risk that member countries will exceed their quotas.

Another issue is whether OPEC members will be able to finance the investments needed to expand their output as projected in the reference case. While some OPEC producer countries are currently closed to foreign involvement in the exploration and development of oil resources, it is expected that they will be able to attract foreign capital, if needed, while retaining

Figure 13. OPEC oil production in four world oil price cases, 1990-2025 (million barrels per day)

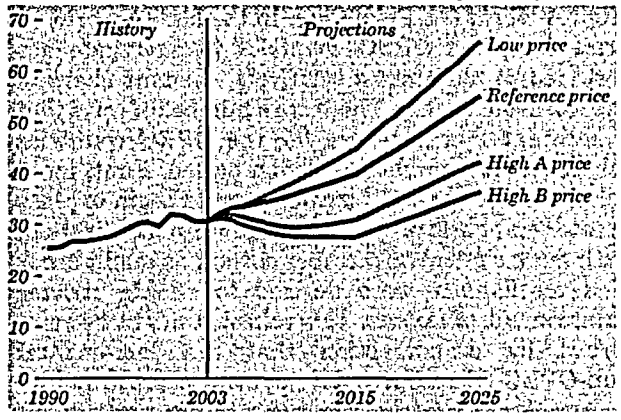


Table 17. Key projections in the reference case, 2003-2025

	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	9.0	208.3	0.2	5.9	3.4
Former Soviet Union and Eastern Europe	3.8	6.5	123.2	2.5	3.5	1.9
Developing countries	5.4	8.2	157.5	2.0	4.4	2.5
Total	17.8	23.7	489.0	1.3	13.8	7.9
OPEC						
Middle East	7.6	14.0	235.4	2.8	6.6	3.7
Other OPEC	3.5	6.1	107.6	2.5	3.0	1.7
Total	11.2	20.1	343.1	2.7	9.7	5.4
Total World	29.0	43.9	832.1	1.9	23.4	13.2

sovereignty over their energy resources. The markets for financial capital have provided sufficient resources in similar situations in the past, especially when there are strong incentives from both the demand and supply sides. The current experience of China, which did not attract much financial capital in the past, is an example of what can happen with the appropriate economic incentives or when the motivations are strong. Other historical examples include the flow of foreign capital to Latin America in the 1980s and East Asia in the 1990s.

There are also factors that may encourage countries in the Middle East to open up their energy sectors to foreign participation in one form or another. For example, Saudi Arabia, for some time now, has been lobbying to gain admission to the World Trade Organization. One of the conditions that Saudi Arabia needs to fulfill to gain entry is to open up its economy, especially its financial markets. The opening up of the United Arab Emirates to foreign financial capital and its creation of an export trade zone provide another example of how the economic environment can change.

High A World Oil Price Case. In the high A world oil price case, the OPEC countries in aggregate are assumed to maintain a relatively constant share of the world oil market. There are a number of ways that a constant market share for the OPEC countries might result over the projection period. First, more cohesion among OPEC members could begin to place greater emphasis on short-term profit maximization, with more control on member output, as might occur if a mechanism were devised to enable stricter enforcement of quotas. This cohesion might be reinforced by a perception that the incremental non-OPEC oil resource development costs are quite high and that the resource base is limited, and thus that there is less risk from non-OPEC producers in the long term. Second, some large producer countries in OPEC might not be able to finance sufficient development and enlargement of productive capacity because of competing social infrastructure demands on government budgets.

In this case, the world oil price would tend to reflect the projected incremental cost of non-OPEC oil and rise faster than in the reference case—from about $28 per barrel in 2003 to more than $39 per barrel in 2025 in real terms, an average annual increase of 1.6 percent from 2003 to 2025. As a result of higher world oil prices, world oil demand in 2025 is projected to be lower in the high A world oil price case than in the reference case (115 million barrels per day and 120 million barrels per day, respectively). Table 18 summarizes the main features of the high A world oil price case.

For OPEC members, cumulative production of almost 280 billion barrels in the high A world oil price case is projected to bring in $9.9 trillion (in 2003 dollars), as compared with cumulative production of 343 billion barrels and revenues of $9.7 trillion in the reference case. Although the high A world oil price case appears to be more attractive to OPEC producers than the reference case in terms of economic profits, the sustainability of the higher prices over the projection period is uncertain. Higher prices would create greater incentive for OPEC countries to exceed quotas, greater likelihood of increased conventional and unconventional oil production in non-OPEC countries, and greater possibility of increased conservation measures in oil-consuming countries, induced both by higher prices and by public policy measures.

Table 18. Key projections in the high A world oil price case, 2003-2025

	World oil production (billion barrels)				*World oil revenues (trillion 2003 dollars)*	
Country/region	*2003*	*2025*	*Cumulative, 2003-2025*	*Average annual growth, 2003-2025 (percent)*	*Cumulative, 2003-2025*	*Cumulative discounted value (at 5%), 2003-2025*
Non-OPEC						
Industrialized countries	8.6	10.0	221.1	0.7	7.8	4.6
Former Soviet Union and Eastern Europe	3.8	7.1	132.2	2.9	4.7	2.7
Developing countries	5.4	9.2	170.4	2.4	6.0	3.5
Total	17.9	26.3	523.7	1.8	18.5	10.8
OPEC						
Middle East	7.6	10.5	189.8	1.5	6.7	3.9
Other OPEC	3.5	4.9	90.6	1.5	3.2	1.9
Total	11.1	15.4	280.4	1.5	9.9	5.8
Total World	29.0	41.7	804.1	1.7	28.4	16.6

While the *AEO* cases are developed under the assumption of unchanged policy in consuming countries, major oil exporters may expect that higher prices would spur policy responses in oil-importing nations. Based on these considerations, economically rational producers would be likely to apply higher discount rates when evaluating the revenue stream associated with the high A world oil price case than that associated with the reference case. Taking this difference into account, key OPEC producers might accept the reference price case.

High B World Oil Price Case. There is a great deal of uncertainty about the size and availability of crude oil resources, particularly conventional resources, the adequacy of investment capital, and geopolitical trends. While the high A world oil price case tries to reflect the uncertainty in some of these variables, some analysts argue that the higher prices seen in recent years will be sustained and represent a fundamental change in the market. The high B world oil price case was completed to evaluate the impact of world oil prices that remain close to current levels for the foreseeable future.

The high B world oil price case assumes a continued rise in prices through 2005, followed by a gradual decline to 2010 and then strong increases through 2025. The near-term prices reflect the trends observed in oil futures on the NYMEX for WTI during October 2004, where crude oil futures prices exceeded 2004 levels in 2005 before falling back somewhat, but to levels well above those projected in the *AEO2005* reference case. The world oil price in the high B case is assumed to be $2 higher than in the reference case in 2004, or $37 per barrel, to grow to about $44 per barrel in 2005 before falling to $37 in 2010, and then to rise to $48 per barrel in 2025, compared with $30 in the reference case and $39 in the high A world oil price case.

The high B world oil price case reflects an assumption that OPEC producers will be less able or willing to expand their productive capacity and that their output growth will be constrained considerably (Table 19). As a result, the OPEC members are projected to lose market share over time, in contrast to the high A world oil price case, where their market share remains constant over time. OPEC member country production is projected to grow from 30.6 million barrels per day in 2003 to 36.6 million barrels per day in 2025, compared with 55.1 million barrels per day in the reference case and 42.4 million barrels per day in the high A world oil price case. The worldwide impacts on energy supply in the high B case are more uncertain because of limited experience with sustained periods of high world oil prices. Nevertheless, roughly one-half of the difference between OPEC member country production in the reference and high B world oil price cases is projected to be made up for by non-OPEC countries (Figure 14). The remaining difference reflects the reduction in oil demand resulting from higher prices, as well as increased production of synthetic oil from coal and natural gas and nonconventional liquids.

Undiscounted cumulative revenues from OPEC member country production in the high B world oil price case exceed those in the reference and high A world oil price cases, despite lower production; however, the high B case is projected to result in significant impacts on world energy demand and alternative sources of supply, including increased production from synthetic fuels. In addition, strong cohesiveness among OPEC members would be required to maintain the strict production quotas implicit in the high

Table 19. Key projections in the high B world oil price case, 2003-2025

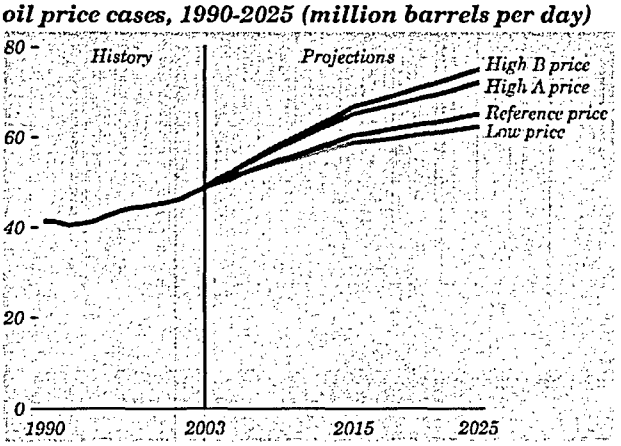
	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	10.2	225.0	0.8	9.2	5.4
Former Soviet Union and Eastern Europe	3.8	7.2	133.4	2.9	5.5	3.1
Developing countries	5.4	9.5	173.1	2.6	7.2	4.1
Total	17.9	26.9	531.5	1.9	21.9	12.6
OPEC						
Middle East	7.6	9.0	171.9	0.8	7.1	4.2
Other OPEC	3.5	4.3	83.3	1.0	3.4	2.0
Total	11.1	13.4	255.2	0.9	10.5	6.2
Total World	29.0	40.3	786.7	1.5	32.4	18.8

B case. As a result, the uncertainty and risk associated with this case for individual OPEC members suggest that a higher rate is appropriate for discounting the projected revenue stream.

The projections in the high B world oil price and reference cases are compared in the text box on page 49. It is important to stress the uncertainties and limitations of this case. The market conditions in the high B world oil price case fall outside the range of experience best represented in NEMS. In particular, some of the modeling uncertainties and limitations about the case are as follows:

- The level of economic production of oil from both conventional sources and unconventional sources (such as oil sands) is subject to considerable uncertainty, particularly with sustained oil prices at much higher levels than in the reference case.
- The effects of global competition for natural gas through pipelines, LNG, and gas-to-liquids (GTL) are highly uncertain in an environment of high sustained oil prices. For example, stranded gas (gas production at sites without access to pipelines) that might otherwise be economical to export as LNG could potentially become economical to process as GTL. These impacts on world natural gas supply cannot be evaluated endogenously with the present versions of EIA's U.S. and global energy models; however, an adjustment to the assumed cost profile of LNG imports to the United States has been incorporated to reflect the potential market impact. As model development is able to continue, additional analytical capability in this area would be a high priority.
- Prospects for synthetic petroleum—GTL and coal-to-liquids (CTL) may be constrained by plant siting issues that have not been investigated, such as waste disposal and limited water supplies.
- The worldwide economic and political response to a regime of prolonged high oil prices is uncertain, as is the long-term effect on domestic economic growth.
- EIA's modeling of petroleum consumption reflects observed patterns of use and consumer preferences, as well as existing and foreseeable technologies. Consumer and manufacturer behavior in the face of sustained high oil prices may depart from the patterns on which the model is based. For example, there could be shifts to smaller, more efficient vehicles, more penetration of alternative-fuel vehicles, and a shift in the demand for vehicular travel to other travel modes, such as from truck to rail freight.
- High world oil prices and high natural gas prices may spur unforeseen technological innovation and adoption, but quantifying these possibilities remains a challenge.

Figure 14. Non-OPEC oil production in four world oil price cases, 1990-2025 (million barrels per day)



Low World Oil Price Case. The low world oil price case reflects a future market where all oil production becomes more competitive and plentiful. There are several ways in which this could come about. First, the OPEC countries could become less cohesive, with each producer attempting to sell as much of its productive capacity as the market will allow. In this sense, the low world oil price case is exactly the opposite of the high A world oil price case. Another possibility would be a decline in the costs of non-OPEC oil production or the viable development of competitive alternatives. To forestall the penetration of alternatives and other sources of competition, OPEC would lower its price band and increase production.

The world oil price (in 2003 dollars) is projected to decline from about $28 per barrel in 2003 to $21 per barrel in 2009 in the low world oil price case, and to stay at that level through 2025. As a result of increased competition between OPEC members or a conscious attempt to increase market share, the market share of OPEC's member countries increases from 39 percent in 2003 to 51 percent in 2025. Within OPEC, nearly all producers, except for Indonesia, which has limited remaining resources, are projected to increase production at an average annual rate of 3 percent or higher over the 2003 to 2025 period. The average annual growth in production by OPEC members over the same period is 3.5 percent. The low world oil prices in this case cause world oil demand to increase from 80 million barrels per day in 2003 to

Comparison of projections in the reference and high B world oil price cases

Higher crude oil prices spur greater exploration and development of domestic oil supplies, reduce demand for petroleum, and slow the growth of oil imports in the high B world oil price case compared to the reference case. Total domestic petroleum supply in 2025 is projected to be 2.2 million barrels a day (25 percent) higher in the high B case than in the reference case. Production in the high B case includes 1.2 million barrels a day in 2025 from synthetic petroleum fuel produced from coal and natural gas. Total net imports in 2025, including crude oil and refined products, are reduced from 19.1 million barrels a day in the reference case to 15.2 in the high B case. As a result, the projected import share of total U.S. petroleum demand in 2025 is 58 percent in the high B world oil price case, compared with 68 percent in the reference case. In 2003, the import share of U.S. petroleum demand was 56 percent.

With the steep, prolonged rise in crude oil prices in the high B world oil price case, the worldwide potential for natural gas and coal-based synthetic fuels would become viable, with implications for imported U.S. supplies of LNG. In the reference case, the United States is expected to become increasingly dependent on LNG, with imports projected to increase from 0.4 trillion cubic feet in 2003 to 6.4 trillion cubic feet in 2025. In the high B case, GTL conversion of stranded natural gas could compete favorably with liquefaction, thus reducing the potential supply of LNG worldwide. As a result, LNG supplied to the United States is projected to be priced higher in the high B world oil price case, leading to higher average end-use natural gas prices than in the reference case and to a 51-percent reduction in projected imports of LNG in 2025. The projected average *delivered* price of natural gas in 2025 (in 2003 dollars) is $7.35 per thousand cubic feet in the high B world oil price case, compared with $6.77 in the reference case.

The higher oil and natural gas prices in the high B world oil price case result in a greater reliance on domestic gas supply, along with a reduction in the projected growth of natural gas consumption. Domestic dry gas production in 2025 in the high B case increases to 23.5 trillion cubic feet, 8 percent higher than the reference case projection of 21.8 trillion cubic feet. In addition, the high price of oil in the high B case results in favorable economics for GTL domestically, leading to an additional 0.7 trillion cubic feet of natural gas consumption for GTL in 2025, offsetting some of the reduction in end-use demand that would result from higher natural gas prices.

The higher natural gas prices in the high B world oil price case would promote greater use of coal technologies for new electricity generation plants, leading to an increase in projected coal consumption of 69 million short tons in 2025 compared to the reference case. In addition, CTL technology to produce petroleum fuels is expected to become economical in the high B world oil price case, resulting in additional coal consumption of 209 million short tons in 2025.

CTL plants are assumed to employ integrated gasification and combined-cycle power generation to produce synthesis gas, process steam, and electric power. CTL plants are considered to be combined heat and power plants, supplying surplus electricity as well as power for on-site use. As a result, an increase of 25 gigawatts of generating capacity from CTL plants is projected in the high B world oil price case. In aggregate, CTL plants are estimated to produce 1 million barrels a day of synthetic liquid fuel in 2025 in the high B world oil price case.

U.S. petroleum demand is reduced in the high B world oil price case, but the modest response to the price changes reflects the limited opportunities for fuel switching in the transportation and industrial sectors, which account for about 90 percent of U.S. oil consumption. Total petroleum consumption is projected to change by only 3 percent in 2010, compared to the reference case, despite a 22-percent higher average price of refined petroleum in 2010. In 2025, petroleum demand is 6 percent lower in the high B world oil price case, and average refined petroleum prices are 32 percent higher.

About two-thirds of the difference in projected petroleum consumption between the reference and high B world oil price cases in 2025 is represented by gasoline. There is very little difference between the projections of demand for transportation uses of diesel and jet fuel, which together accounted for one-third of the petroleum used in the transport sector in 2003. The demand for diesel fuel to move freight in trucks, rail, and shipping is relatively insensitive to price changes, as the equipment used is long-lived and the prospects of efficiency improvements for freight carriers are more limited than

(continued on page 50)

Comparison of projections in the reference and high B world oil price cases (continued)

those for passenger transportation. In addition, there is some projected increase in rail and shipping in the high B world oil price case as a result of increased coal use in the electricity sector, offsetting some of the fuel saved by efficiency improvements in the freight truck fleet. Potential energy savings beyond those projected in the high B world oil price case would be possible if there were greater shifts among modes of travel, such as increased use of rail in place of trucking.

The demand for jet fuel is expected to be insensitive to price increases through 2025, as air travel growth is constrained by the availability of airport capacity in that time frame. The changes in fuel costs are unlikely to bring air travel demand down below the limits imposed by available airport capacity, eliminating much of the expected price response. The reduction in jet fuel between the reference and the high B world oil price cases, 1.6 percent in 2025, occurs primarily due to adoption of technology to increase aircraft efficiency.

Growth in projected gasoline demand in the high B world oil price case is lower than the reference case, as consumers respond to higher increased fuel costs by reducing the number of vehicle miles traveled and by purchasing more efficient automobiles. The projected price of gasoline in 2025 in the high B world oil price case is $2.01 a gallon (2003 dollars), compared to $1.59 in the reference case. As a result, average fuel economy of new, light-duty vehicles in 2025 increases from 26.9 miles per gallon in the reference case to 28.2 in the high B world oil price case. Even greater fuel economy improvements might occur under a high price scenario if consumers and manufacturers departed from recent trends and shifted to smaller, less powerful vehicles, or if there was a greater penetration rate of hybrid and diesel vehicles than is projected. However, at gasoline prices at or below $2.00 a gallon, significant changes in consumer behavior are not expected.

The U.S. economy is sensitive to oil price spikes, and several recessions have followed supply disruptions in recent decades; however, gradual changes in oil prices are less damaging to long-term economic growth, because the economy has more time to adjust. The projected impact on real GDP in the high B world oil price case, compared to the reference case, is $53 billion (2000 dollars) in 2010 (0.4 percent) and $32 billion in 2025 (0.2 percent). The macroeconomic results suggest that the U.S. economy would continue to fare well in the face of rising oil prices, provided that prices rose gradually over a long period of time; however, this analysis does not consider the potential impacts on the United States of worldwide economic disruption that might occur as a result of sustained high oil prices.

128 million barrels per day in 2025, an average annual increase of 2.2 percent.

Given the projected state of technology, projected reserves, and their relatively higher cost structures, non-OPEC producers would be expected to increase output at a slower rate in the low world oil price case than in the reference case (Figure 14). Starting from a production level of 49 million barrels per day in 2003, non-OPEC oil output is projected to grow at an average annual rate of 1.1 percent in the low price case, to 62 million barrels per day in 2025. Table 20 summarizes the main features of the low world oil price case.

The low oil price case is the most favorable of the *AEO2005* oil price cases in terms of economic welfare, because the world oil price is projected to be closer to its marginal cost. It is less favorable, however, from the producers' point of view. Relative to the reference case, OPEC members would end up producing 11 percent more oil over the 2003 to 2025 period and earning roughly 11 percent less in cumulative revenues. Further, with a decline in oil prices there would be less exploration activity at the margin, a tendency for more cohesion in OPEC, and lower penetration of alternative fuels.

Changing Trends in the Bulk Chemicals and Pulp and Paper Industries

Compared with the experience of the 1990s, rising energy prices in recent years have led to questions about expectations of growth in industrial output, particularly in energy-intensive industries. Given the higher price trends, a review of expected growth trends in selected industries was undertaken as part of the production of *AEO2005*. In addition, projections for the industrial value of shipments, which were based on the Standard Industrial Classification (SIC) system in *AEO2004*, are based on the North American Industry Classification System (NAICS) in *AEO2005*. The change in industrial classification leads to lower historical growth rates for many industrial sectors. The impacts of these two changes are

Table 20. Key projections in the low world oil price case, 2003-2025

Country/region	World oil production (billion barrels) 2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	World oil revenues (trillion 2003 dollars) Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	8.5	202.8	0.0	4.7	2.9
Former Soviet Union and Eastern Europe	3.8	6.3	121.1	2.3	2.7	1.6
Developing countries	5.4	7.9	153.8	1.8	3.5	2.1
Total	17.8	22.7	477.8	1.1	10.9	6.5
OPEC						
Middle East	7.6	16.9	264.0	3.7	5.9	3.4
Other OPEC	3.5	7.1	117.7	3.2	2.6	1.5
Total	11.2	24.0	381.7	3.5	8.6	4.9
Total World	29.0	46.7	859.5	2.2	19.5	11.4

highlighted in this section for two of the largest energy-consuming industries in the U.S. industrial sector—bulk chemicals and pulp and paper.

Output growth rates for the pulp and paper industry and the bulk chemical industry have been revised downward in *AEO2005* to align better with historical trends. Models for both industries in NEMS have also been revised to reflect recent trends in their specific production processes. In combination, these changes have had an important impact on the *AEO2005* forecast for industrial energy consumption.

The scope of activities included in the industrial sector (which includes agriculture, mining, construction, and manufacturing) and how they are defined have changed with the move to NAICS. For example, publishing, logging, and manufacturers' administrative and auxiliary services that are not co-located with manufacturing establishments are no longer covered in the manufacturing sector but are now included in the commercial sector. Under NAICS, the manufacturing sector is about 3 percent smaller in terms of value and 4 percent smaller in terms of employment than under SIC in 1997, the only year for which economic census data are available for both classification systems.

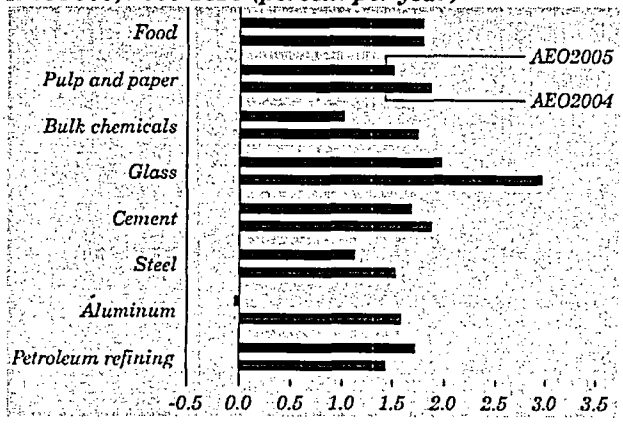
The *AEO2005* industrial forecast reflects both changes in economic conditions and changes in historical growth rates as a result of the move from SIC to NAICS. The projected growth rates for most energy-intensive industries are lower in *AEO2005* than in *AEO2004*, in part because the historical growth rates have been revised downward. Figure 15 compares the growth rates projected for selected energy-intensive industries in *AEO2005* and *AEO2004*.

Pulp and Paper

AEO2004 projected that paper final product would grow by an average of 1.9 percent annually from 2003 to 2025; however, the intermediate steps in the industry, and the energy use associated with them, were expected to grow at different rates as the mix of technologies changed and costs shifted. For example, between 2003 and 2025, kraft pulping was projected to grow by 2.1 percent per year while semi-chemical pulping grew by 0.9 percent per year. Mechanical pulping was projected to decline by 0.5 percent per year over the same period.

From 1983 to 2000, paper and board production grew by 2.1 percent per year while total pulping grew by only 1.1 percent per year. Although long-term data for the individual pulping steps is limited, kraft pulping, because of its superior technology [*80*], is the primary pulping method, accounting for 86 percent of

Figure 15. Projected growth in output for energy-intensive industries in AEO2004 and AEO2005, 2003-2025 (percent per year)



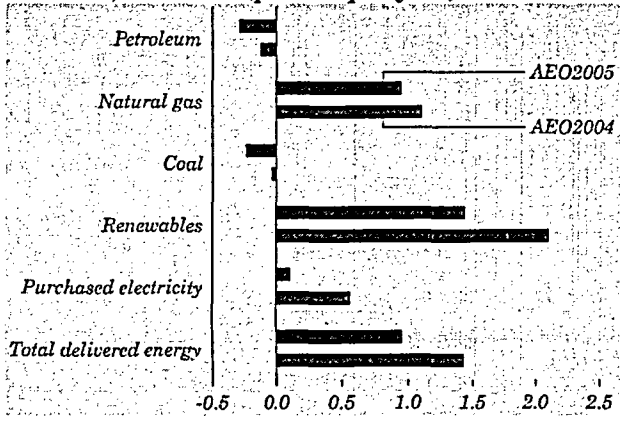
virgin pulping in 2002. Between 1996 and 2002, kraft pulping increased while semi-chemical pulping declined, and mechanical pulping dropped by more than 20 percent [*81*].

Growth in final paper and board production, coupled with slower growth or a decline in the intermediate pulping steps, is made possible by increases in recovered paper and imports of market pulp. Consumption of recovered paper at paper and board mills increased by 5 percent annually from 1983 to 2002, and the United States has gone from being a net exporter of market pulp in 1997 to a net importer in 2002, importing about 15 percent more than it exports [*82*].

The *AEO2004* results were reviewed relative to the trends outlined above, and revisions were made as necessary. As a result of the changes made and a lower forecast of growth in final industrial production in *AEO2005*, waste pulping, which consists of recovered paper and market pulp, is projected to grow by 2.0 percent per year from 2003 to 2025; mechanical pulping is projected to decline by 0.8 percent per year; and semi-chemical and kraft pulping are projected to grow by 0.7 percent per year and 1.4 percent per year, respectively. Pulp and paper output is projected to grow by 1.5 percent per year.

The most notable impact of these revisions and updates is that the projected growth of purchased electricity for the pulp and paper sector falls to only 0.1 percent per year in *AEO2005*, from 0.6 percent per year in *AEO2004* (Figure 16). The use of all fuels in the pulp and paper industry is projected to grow more slowly (or decline faster) in *AEO2005* than in *AEO2004*. Total energy consumption for the pulp and paper industry is projected to grow at an annual rate of 0.9 percent per year from 2003 to 2025 in *AEO2005*, compared with 1.4 percent per year in *AEO2004*.

Figure 16. Projected growth in energy consumption for the pulp and paper industry in AEO2004 and AEO2005, 2003-2025 (percent per year)

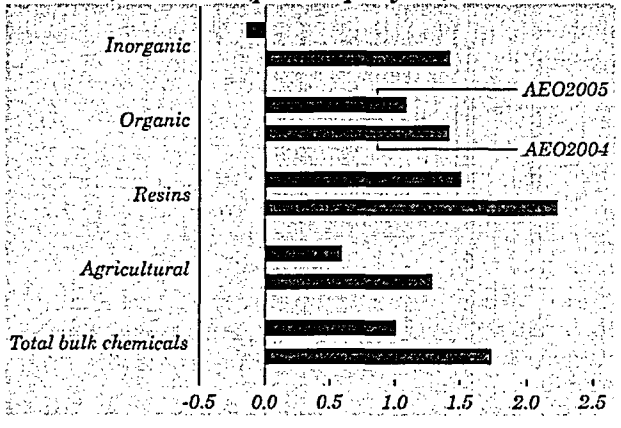


Bulk Chemicals

The bulk chemical industry is dependent on natural gas and petroleum as material inputs (feedstocks) and as fuels for heat and power. The bulk chemical industry model used for *AEO2005* was revised to address separately the four subsectors of the bulk chemical industry: inorganic, organic, resins, and agricultural chemicals [*83*]. Figure 17 compares the projected output growth rates for each component of the bulk chemical industry in *AEO2004* and *AEO2005*.

The growth rate for the total bulk chemical industry is projected to be 1.0 percent per year in *AEO2005*, compared with 1.7 percent per year in *AEO2004*. The largest changes are for the inorganic and agricultural chemicals components of the bulk chemical industry. The inorganic chemicals industry is a mature industry [*84*] that has grown slowly over the past several years. Its limited growth prospects are better represented in *AEO2005*, where the projected growth rate for inorganic chemicals is close to zero as compared with 1.4 percent per year in *AEO2004*. The agricultural chemicals subsector, which includes the production of nitrogenous fertilizers, has faced increased competition from foreign suppliers due to relatively high U.S. natural gas prices [*85*]. The *AEO2005* forecast reflects the current competitive situation. This update reduced projected growth from 1.3 percent per year in *AEO2004* to 0.6 percent per year in *AEO2005*. The organic and resins components have exhibited a tendency toward increasing use of imports of energy-intensive intermediate products in preference to domestically manufactured products [*86*], and that tendency is reflected in a lower assumed energy intensity for new or replacement plant.

Figure 17. Projected output growth for components of the bulk chemicals industry in AEO2004 and AEO2005, 2003-2025 (percent per year)



The combination of lower projected output growth and a shift to less energy-intensive production processes leads to lower projected growth in energy consumption for the bulk chemical industry in *AEO2005* than was projected in *AEO2004* (Figure 18). Despite these changes, however, the bulk chemical industry remains the largest energy-consuming industry in the industrial sector. In 2003, the bulk chemical industry consumed 6.3 quadrillion Btu of energy (including feedstocks), and that total is projected to grow to 7.5 quadrillion Btu in 2025, about 1 quadrillion Btu less than was projected in *AEO2004*. Feedstock consumption is projected to increase from 3.5 quadrillion Btu in 2003 to 4.3 quadrillion Btu in 2025 in the *AEO2005* forecast, 0.4 quadrillion Btu less than was projected in *AEO2004*.

In summary, the transition from SIC to NAICS, reduced rates of output growth, and revised modeling have reduced the *AEO2005* projection of industrial energy consumption in 2025 by 2.6 quadrillion Btu (8 percent) from the *AEO2004* projection. Lower natural gas consumption accounts for about two-thirds of the difference between the two projections.

Fuel Economy of the Light-Duty Vehicle Fleet

The U.S. fleet of light-duty vehicles consists of cars and light trucks, including minivans, sport utility vehicles (SUVs) and trucks with gross vehicle weight less than 8,500 pounds. The fuel economy of light-duty vehicles is regulated by the CAFE standards set by NHTSA. Currently, the CAFE standard is 27.5 miles per gallon (mpg) for cars and 20.7 mpg for light trucks. The most recent increase in the CAFE standard for cars was in 1990, and the most recent increase in the CAFE standard for light trucks was in 1996.

There has been little improvement in the average fuel economy of new cars and light trucks sold in the United States over the past 15 years (Figure 19), but the combined average fuel economy for all new light-duty vehicles has declined steadily because of an increase in sales of light trucks. Since 1987, the average fuel economy of new light-duty vehicles sold has remained relatively constant, averaging 28.5 mpg for cars and 21.1 mpg for light trucks. For model year 2003, cars achieved the highest measured CAFE to date, averaging 29.4 mpg. The highest light truck CAFE was achieved in 1987 at 21.7 mpg, but light truck CAFE has been increasing in recent years, to 21.6 mpg for model year 2003 [*87*]. The fuel economy of light trucks is expected to improve over the next 3 years, because NHTSA announced new standards in April 2003 that increased the requirements to 21.0 mpg for model year 2005, 21.6 mpg for model year 2006, and 22.2 mpg for model years 2007 and beyond.

Although the relatively flat fuel economy for cars and light trucks over the past 15 years may suggest little technological improvement, this is not the case. Instead, technological advances have led to significant improvements in vehicle performance and increases in vehicle size, while generally maintaining or slightly increasing fuel economy. Based on NHTSA data, the average new car in 1990 achieved 28.0 mpg, had a curb weight of 2,906 pounds, and produced 132 horsepower. In 2002, average new car fuel economy was 3.2 percent higher at 28.9 mpg, curb weight was 8.7 percent higher at 3,159 pounds, and engine size was 30.0 percent higher at 171 horsepower [*88*]. Thus, although fuel economy improvements have been minimal, the introduction of advanced

Figure 18. Projected growth in energy consumption for the bulk chemicals industry by energy source in AEO2004 and AEO2005, 2003-2025 (percent per year)

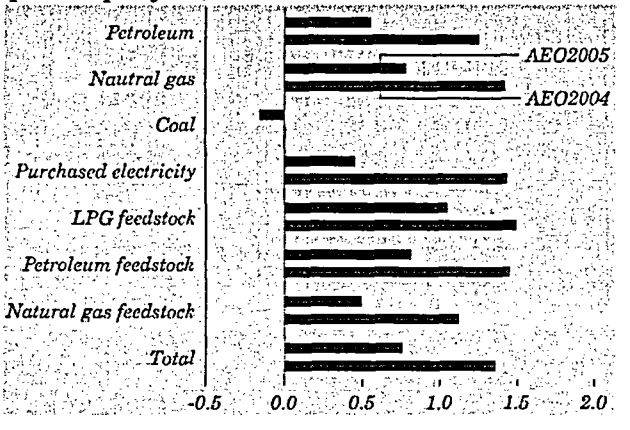
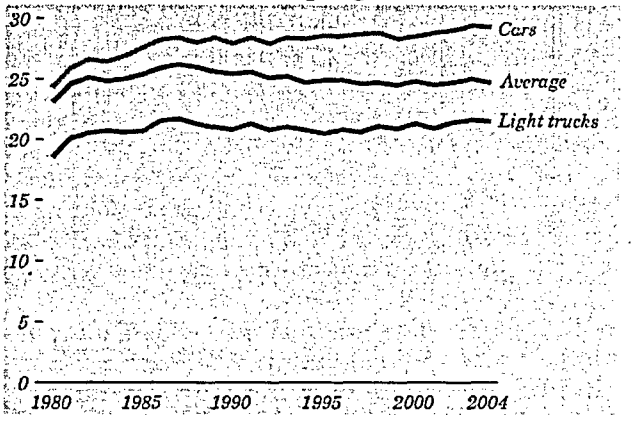


Figure 19. Average fuel economy for new light-duty vehicles, 1980-2004 (miles per gallon)



technologies (including variable valve timing and lift, electronic engine and transmission controls, lock-up torque converters, and five-speed automatic transmissions) have produced significant improvement in engine and transmission efficiency, allowing substantial increases in new car size and performance. Data from the EPA show similar performance trends. For example, from 1990 to 2002, average new car horsepower per cubic inch displacement, a measure of engine efficiency, increased by 28.6 percent, from 0.83 to 1.07, as a result of implementation of advanced technologies and improved engine designs [*89*].

Similar improvements in vehicle attributes have also occurred for light trucks. In 1990, the average new light truck achieved 20.8 mpg, had a curb weight of 4,005 pounds, and produced 151 horsepower. In 2002, the average fuel economy for new light trucks was 4.8 percent higher at 21.8 mpg, curb weight was 13.5 percent higher at 4,547 pounds, and engine size was 45.7 percent higher at 220 horsepower. As in the case of cars, manufacturers have provided improved fuel economy for light trucks while increasing vehicle size and performance by implementing advanced technologies. From 1990 to 2002, light truck horsepower per cubic inch displacement increased by 37.4 percent, from 0.67 to 0.92.

In addition to increases in weight and performance, the mix of new vehicles sold has changed dramatically over the past 20 years. In 1983, cars accounted for 76.5 percent of new light-duty vehicles sold; in 2003, they accounted for only 47.2 percent. In addition, sales of subcompact cars, as a percent of total new vehicles sold, decreased from 20.5 percent in 1983 to 2.8 percent in 2003. Compact, midsize, and large car sales as a percent of total new light-duty vehicle sales have also declined.

Since 1983, sales of new light trucks, including SUVs, have increased significantly. In 2002, light trucks made up the majority of new light-duty vehicle sales. Increases in light truck sales over the past 20 years can be attributed to increased consumer demand for vehicle utility, seating capacity, ride height, and perceived safety. Coupled with low fuel prices, this trend has provided a favorable market for new light trucks, with sales of SUVs and minivans accounting for most of the increase in light truck sales. In 1983, SUVs accounted for 2.9 percent of new light-duty vehicle sales; in 2003, SUVs accounted for 27.0 percent of new light-duty vehicle sales and represented the largest segment of the light-duty vehicle market. Similarly, sales of minivans have grown dramatically. In 1983, minivans accounted for 0.1 percent of new light-duty vehicle sales; in 1994, they reached a peak share of 9.2 percent; and in 2003 their share was 6.5 percent of new light-duty vehicle sales [*90*].

Although significant improvements have been made in light-duty vehicle engine and transmission efficiency, consumer demand for increased performance and vehicle size, coupled with the growth of the light truck market, has resulted in an average new light-duty vehicle fuel economy that peaked at 26.2 mpg in 1987. New light-duty vehicle fuel economy declined steadily throughout the 1990s, to a low of 24.5 mpg in 1999, followed by an increase to 25.0 mpg for model year 2003 vehicles.

The *AEO2005* reference case projects that, in addition to increases in market penetration of advanced technologies, sales of hybrid and diesel vehicles will continue to increase. As a result, new car fuel economy in 2025 is projected to average 31.0 mpg, and new light truck fuel economy is projected to average 24.6 mpg—increases of 5.4 percent for cars and 14.1 percent for light trucks over the respective model year 2003 CAFE levels. Similar to historic trends, average engine power output is projected to increase to 215 horsepower for new cars sold in 2025 (26.3 percent higher than model year 2003) and 243 horsepower for new light trucks sold in 2025 (18.0 percent higher than model year 2003). Light truck sales are projected to account for 58.6 percent of new light-duty vehicle sales in 2025, and as a result the average fuel economy for all new light-duty vehicles sold is projected to increase by 7.2 percent, to 26.9 mpg in 2025.

Recent introductions of more efficient crossover vehicles (SUVs with design features more similar to those of cars than trucks), increasing consumer interest in environmentally friendly vehicles, the possibility of sustained high fuel prices, and increasing consumer demand for improvements in vehicle performance and luxury all will influence the future of light-duty vehicle sales and fuel economy. In addition, carbon emission regulations for light-duty vehicles that have been issued in eight U.S. States and Canada would require improvements in vehicle fuel economy starting in 2009 that go beyond those required by current U.S. CAFE standards. (*AEO2005* does not include the impact of these carbon emission regulations, because their future is uncertain. The auto industry has filed suit against the regulations established in California, contending that only the Federal Government has the authority to set vehicle fuel economy standards. See "Legislation and Regulations," page 27.) NHTSA is also considering modification of light truck CAFE

standards, which could result in the redefinition of a light truck as well as a restructuring of the standards to be based on vehicle weight and/or size.

In summary, considerable uncertainty surrounds the future of light-duty vehicle fuel economy. Fuel prices, the market success of hybrid and diesel vehicles, continued increases in consumer demand for light trucks and better vehicle performance, potential new fuel economy standards, and future regulation of carbon dioxide emissions all have potentially significant impacts on the automobile industry and the vehicles that will be manufactured and sold in the future.

U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*91*]. A key goal of the Climate Change Initiative is to reduce U.S. greenhouse gas intensity by 18 percent over the 2002 to 2012 time frame. For the purposes of the initiative, greenhouse gas intensity is defined as the ratio of total U.S. greenhouse gas emissions to economic output.

AEO2005 projects energy-related carbon dioxide emissions, which represented approximately 84 percent of total U.S. greenhouse gas emissions in 2002. Projections for the other greenhouse gases are based on an EPA "Business-as-Usual" (BAU) case cited in the Addendum to the *Global Climate Change Policy Book* [*92*] released with the Global Climate Change Initiative. Those projections are based on several EPA-sponsored studies conducted in the preparation of the U.S. Department of State's *Climate Action Report 2002* [*93, 94, 95, 96*]. Table 21 combines the *AEO2005* reference case projections for energy-related carbon dioxide emissions with the projections for other greenhouse gases.

According to the combined emissions projections in Table 21, the greenhouse gas intensity of the U.S. economy is expected to decline by 14 percent from 2002 to 2012 and by 30 percent from 2002 to 2025 in the reference case. The Administration's goal of reducing greenhouse gas intensity by 18 percent by 2012 would require an emissions reduction of about 366 million metric tons carbon dioxide equivalent from the projected level in the reference case.

Although *AEO2005* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent intensity reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors, carbon dioxide emissions in 2012 are projected to be 129 million metric tons less than the reference case projection. As a result, U.S. greenhouse gas intensity would fall by 15.5 percent from 2002 to 2012, still somewhat short of the Administration's goal of 18 percent (Figure 20). An 18-percent decline in intensity is projected to occur by 2014 in the integrated high technology case, as compared with 2015 in the reference case.

Impacts of Temperature Variation on Energy Demand in Buildings

In the residential and commercial sectors, heating and cooling account for more than 40 percent of

Table 21. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025

	Projection			Percent Change	
Measure	*2002*	*2012*	*2025*	*2002-2012*	*2002-2025*
Greenhouse gas emissions (million metric tons carbon dioxide equivalent)					
Energy-related carbon dioxide	5,750	6,812	8,062	18.5	40.2
Methane	599	609	606	1.7	1.1
Nitrous oxide	323	342	382	5.7	18.3
Gases with high global warming potential	144	284	624	97.5	334.0
Other carbon dioxide and adjustments for military and international bunker fuel	60	82	93	37.2	56.9
Total greenhouse gases	6,876	8,128	9,767	18.2	42.1
Gross domestic product (billion 2000 dollars)	10,075	13,869	20,292	37.7	101.4
Greenhouse gas intensity (thousand metric tons carbon dioxide equivalent per billion 2000 dollars of gross domestic product)	682	586	481	-14.1	-29.5

end-use energy demand. As a result, energy consumption in those sectors can vary significantly from year to year, depending on yearly average temperatures.

In long-term energy forecasting, an average of the heating and cooling degree-days data for the previous 30 years is ordinarily used as a proxy for "normal" weather [97]. Both heating and cooling degree-days have shown a slight warming trend since 1973 (Figure 21), although no warming trend is evident from an examination of the long-term data since 1930. The direction of year-to-year fluctuations in U.S. average heating degree-days and in U.S. average cooling-degree days do not appear to be correlated; however, both the lowest yearly average for heating degree-days and the highest yearly average for cooling degree-days were recorded in 1998. The coldest winter over the 1973-2003 period (1978) was 11 percent colder than the average, and the warmest winter (1998) was 12 percent warmer than the average. The coolest summer (1976) was 16 percent cooler than the average, and the warmest summer (1998) was 15 percent warmer than the average.

The *AEO2005* reference case uses the 30-year average of heating and cooling degree-days from the National Oceanic and Atmospheric Administration at the State level, adjusted for State population forecasts through 2025, to represent future temperatures (previous *AEO*s used Census division forecasts). As a result of State population shifts, population-weighted heating degree-days are projected to decline by 3.2 percent, and population-weighted cooling degree-days are projected to increase by 4.1 percent from 2003 to 2025, relative to the weather normal average assumed in 2005, because the population is projected to shift to States with warmer climates.

To estimate the possible impact of warmer or colder weather on energy use in the residential and commercial sectors, two alternative cases were examined: a warmer case assuming above-average temperatures and a cooler case assuming below-average temperatures throughout the projection period. For this analysis, it was assumed that State-level heating and cooling degree-days would reach the average of the five warmest or coolest levels that have occurred over the past 30 years by 2025. It was also assumed that warmer winters would coincide with warmer summers, and vice versa. Figures 22 and 23 show the projected trends in heating and cooling degree-days from 2005 to 2025 in the reference, warmer, and cooler cases. Compared with the reference case forecast, heating degree-days are projected to be 11 percent higher in the cooler case and 12 percent lower in the warmer case by 2025, and cooling degree-days are projected to be 17 percent higher in the warmer case and 16 percent lower in the cooler case.

The impacts of the assumptions in the warmer and cooler weather cases on projected energy consumption in the residential and commercial sectors are mixed, because warmer winters reduce demand for space heating (generally fossil fuels) and warmer summers increase demand for space cooling (generally electricity), whereas colder winters and summers do the opposite. Figure 24 shows the impacts of the two cases on electricity consumption (including conversion losses) and direct fossil fuel consumption.

Given that fossil-fuel-fired space heating is the largest use of energy in the two buildings sectors, it is not surprising that the cumulative change in the two weather cases is greatest for fossil fuels. The cumulative change in fossil fuel consumption in the buildings

Figure 20. Projected change in U.S. greenhouse gas intensity in three cases, 2002-2025 (percent)

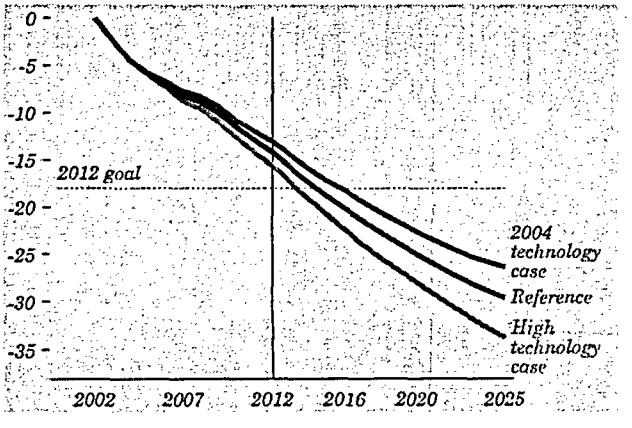
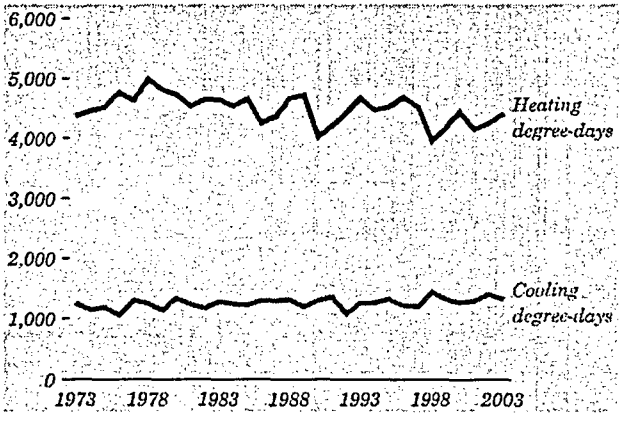


Figure 21. U.S. average heating and cooling degree-days, 1973-2003



sector in the warmer and colder cases represents 2.4 and 1.9 percent, respectively, of the cumulative amount of fossil fuels used in the buildings sector from 2006 through 2025. For electricity, the cumulative change is 0.2 percent of the cumulative amount of electricity (including conversion losses) used in the buildings sector in both cases between 2006 and 2025. The much lower change for electricity is due to the fact that much less of the electricity load is temperature dependent—only 16 percent, compared with 62 percent for fossil fuels. For example, many of the major end-use services that are not temperature dependent, such as lighting, refrigeration, and office equipment, are powered almost exclusively by electricity.

Changes in projected energy demand in the warmer and cooler cases also affect the projections of energy prices. Relative to the *AEO2005* reference case, average residential and commercial electricity prices in the cooler case are 0.7 percent and 0.5 percent lower over the projection period, respectively, as summer peak demand is reduced by decreases in air conditioning use. In the warmer case, average electricity prices to residential and commercial customers over the period from 2006 to 2025 are 0.8 percent and 0.9 percent higher, respectively, as summer peak load is increased.

Figure 22. Projected U.S. average heating degree-days in three cases, 2000-2025

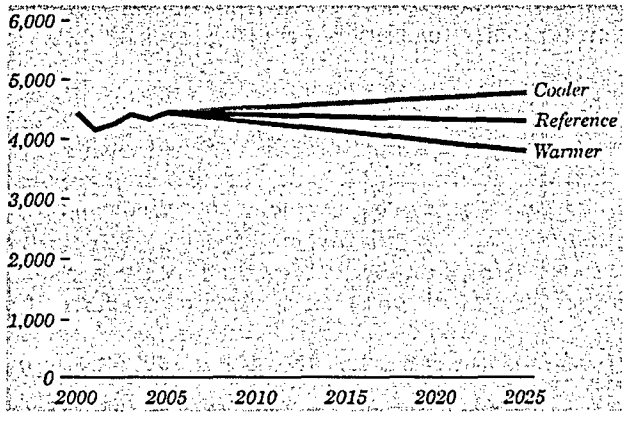
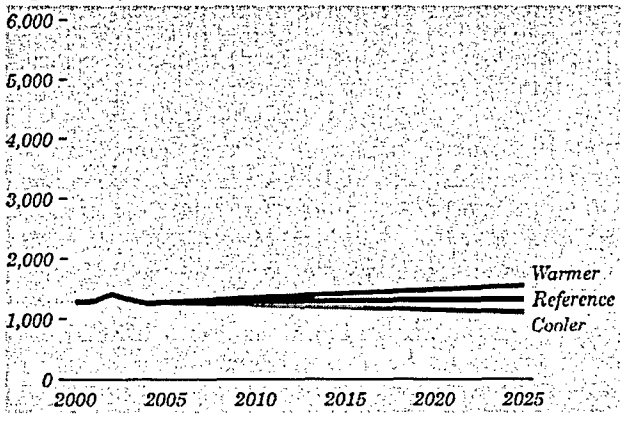


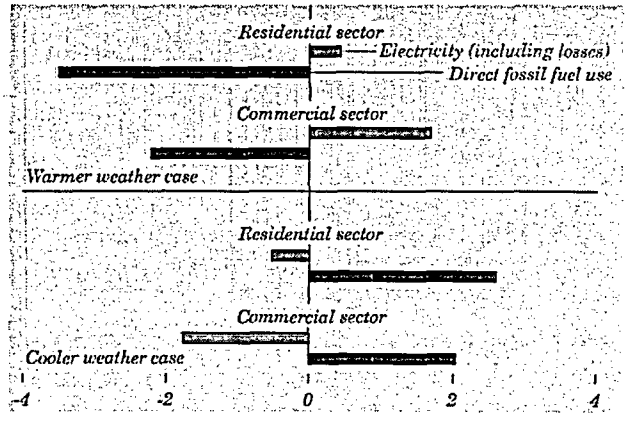
Figure 23. Projected U.S. average cooling degree-days in three cases, 2000-2025



The changes in electricity demand are not evenly distributed throughout the year; there is a much greater change in peak demand than there is in total demand. This also affects the amount of electric generating capacity needed, which is based on an assumed reserve over the peak demand. In the warmer case, peak demand in 2025 is 4.8 percent higher than in the reference case, resulting in a 3.5-percent increase in overall electricity generation capacity, although total demand in 2025 is only 0.5 percent higher than in the reference case. As a result, higher average electricity prices are projected, due to the increased costs of capacity without an equal increase in generation. The incremental cost is spread over relatively few additional kilowatthours. In the colder case, projected peak demand in 2025 is 4.4 percent lower than in the reference case, and total capacity is 3.2 percent lower, although total demand is only 0.7 percent lower. In this case, total costs are lower due to fewer new capacity additions, but total demand is again almost the same, and average prices are lower.

Because changes in annual energy demand vary depending on season and fuel type in the two weather cases, it follows that changes in energy expenditures will vary as well. As shown in Figure 24, demand for fossil fuel and electricity change in opposite directions relative to the reference case in the two temperature

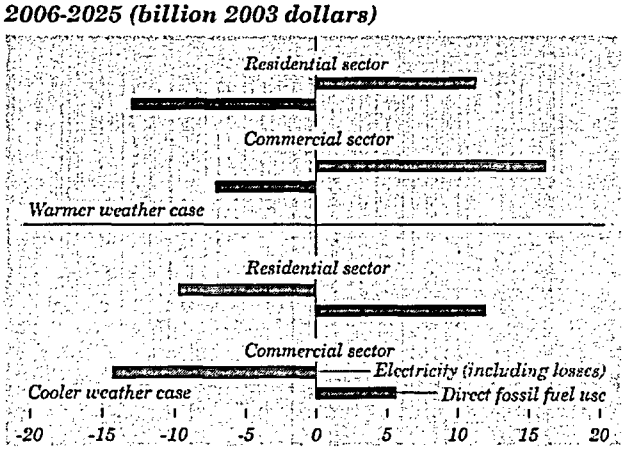
Figure 24. Cumulative projected change from the reference case in buildings sector electricity and fossil fuel use in two cases, 2006-2025 (quadrillion Btu)



sensitivity cases. Figure 25 shows the changes in projected present value of expenditures for electricity and fossil fuels in the residential and commercial sectors in the warmer and colder cases. The present value of commercial electricity expenditures changes the most, but the difference, as a percentage of current commercial electricity expenditures, reaches only 1.3 percent over the present value of all future expenditures on electricity in the sector. The present value of residential energy expenditures increases by $2.3 billion in the cooler case, meaning that consumers could expect to pay more money for their household energy use over the projection period. In the warmer case, the present value of residential energy expenditures decreases by $1.6 billion, reflecting the larger heating requirements relative to cooling requirements in the sector.

In summary, average yearly temperatures that are warmer or cooler than expected would have mixed impacts on energy consumption and expenditures in the residential and commercial sectors if the changes were directionally the same in the heating and cooling seasons. Warmer summer temperatures would increase demand for air conditioning, and warmer winter temperatures would decrease demand for heating. Because space heating accounts for more energy use than air conditioning on the basis of sales volumes, heating fuels tend to be more affected by changes in temperature than do cooling fuels; however, given the relatively high delivered price of electricity compared to fossil fuels, changes in energy consumption tend to affect electricity more on the basis of total expenditures.

Figure 25. Present value of projected change from the reference case in buildings sector expenditures for electricity and fossil fuel use in two cases, 2006-2025 (billion 2003 dollars)



The projections in the warmer and cooler weather cases show that energy consumption and expenditures are sensitive to changes in temperature. It should be noted, however, that the changes projected are relatively small relative to the sector totals. Accordingly, in the colder case, cumulative carbon dioxide emissions from 2003 to 2025 are projected to be only 0.1 percent higher than in the reference case, and in the warmer case they are projected to be only 0.2 percent lower than in the reference case.

Production Tax Credit for Renewable Electricity Generation

In the late 1970s and early 1980s, environmental and energy security concerns were addressed at the Federal level by several key pieces of energy legislation. Among them, the Public Utility Regulatory Policies Act of 1978 (PURPA), P.L. 95-617, required regulated power utilities to purchase alternative electricity generation from qualified generating facilities, including small-scale renewable generators; and the Investment Tax Credit (ITC), P.L. 95-618, part of the Energy Tax Act of 1978, provided a 10-percent Federal tax credit on new investment in capital-intensive wind and solar generation technologies [*98*].

EPACT included a provision that addresses problems with the ITC—specifically, the lack of incentives for operation of wind facilities. EPACT introduced the renewable electricity PTC, a credit based on annual production of electricity from wind and some biomass resources. The initial tax credit of 1.5 cents per kilowatthour (1992 dollars) for the first 10 years of output from plants entering service by December 31, 1999, has been adjusted for inflation and is currently valued at 1.8 cents per kilowatthour (2003 dollars) [*99, 100*].

The original PTC applied to generation from taxpaying owners of new wind plants and biomass power plants using fuel grown in a "closed-loop" arrangement (crops grown specifically for energy production, as opposed to byproducts of agriculture, forestry, urban landscaping, and other activities). In its early years, the PTC had little discernable effect on the wind and biomass industries it was designed to support (Figure 26). Although there have not been any commercial closed-loop generators, by 1999, when the provision was originally set to expire, U.S. wind capacity had begun growing again, and the PTC supported the development of more than 500 megawatts of new wind capacity in California, Iowa, Minnesota, and other States. Wind power development was also encouraged by State-level programs, such as the

mandate in Minnesota for 425 megawatts of wind power by 2003 as part of a settlement with Northern States Power (now Xcel Energy) to extend on-site storage of nuclear waste at its nuclear facility [*101*].

In 1999, the PTC was allowed to expire as scheduled, but within a few months it was retroactively extended through the end of 2001 [*102*], and poultry litter was added to the list of eligible biomass fuels. Although wind power development slowed significantly in 2000, 2001 was a record year with as much as 1,700 megawatts installed [*103*]. Again, State and local programs, including a significant renewable energy mandate program in Texas, also supported new wind installations.

The PTC was allowed to expire again on December 31, 2001, while Congress worked on a comprehensive new energy policy bill. It was retroactively extended a second time to December 31, 2003, as part of an omnibus package of extended tax credits passed in response to the economic downturn and terrorist attacks of 2001 [*104*].

Like the 1999 expiration and extension, the extension of the PTC in 2002 was followed by a lull in wind power development; however, in 2003, the year leading up to the expiration, the wind industry saw significant growth of almost 1,700 megawatts [*105*], approaching the record set in 2001. Significantly, while many 2003 builds still relied on multiple incentives (for example, the PTC plus a State program) to achieve economic viability, some (in Oklahoma and other States) were developed with little government support beyond the PTC [*106*].

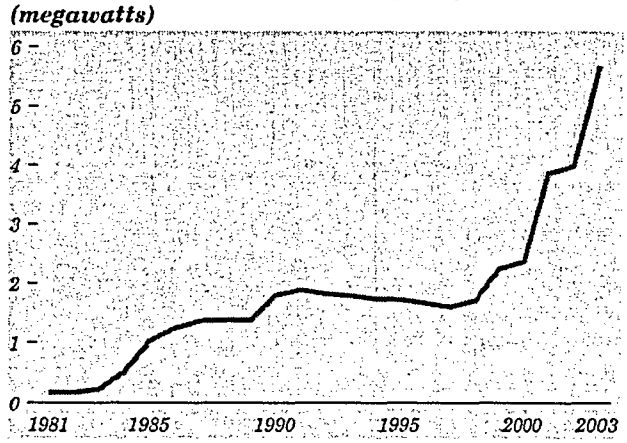
An extension of the PTC program to eligible plants entering service on or before December 31, 2005, was passed as part of the Working Families Tax Relief Act of 2004 (P.L. 108-311). In addition, the American Jobs Creation Act of 2004 (P.L. 108-357) expanded the credit to other renewable resources, such as open-loop biomass, geothermal, and solar electricity, as detailed below.

With reductions in capital costs and increases in capacity factors [*107*], wind power technology has improved since the introduction of the ITC and PTC. It is likely that the installations spurred by those incentives allowed the industry to "learn by doing" and thus contributed to improvement of the technology. There were, however, other factors that contributed to cost reductions during the period, including government-funded research and development and large markets for wind power technology that were created by subsidy programs in other countries, especially, Denmark and Germany.

The *AEO2005* reference case, assuming no extension of the PTC beyond 2005 (as provided for in current law as of October 31, 2004), projects that the levelized cost of electricity generated by wind plants coming on line within the next few years would range from approximately 4.5 cents per kilowatthour at a site with excellent wind resources [*108*] to 6.0 cents per kilowatthour at less favorable sites. To incorporate the effect of the current 1.8-cent tax credit over the 10-year eligibility period for those wind plants, the projections account for both the tax implications and the time value of the subsidy. As a tax credit, the PTC represents 1.8 cents per kilowatthour of tax-free money to a project owner. If the owner did not receive the tax credit and wanted to recoup that 1.8 cents with taxable revenue from electricity sales, 2.8 cents would have to be added to the sales price of each kilowatthour, assuming a 38-percent marginal tax rate.

Applying the same assumptions used to derive the 4.8-cent total levelized cost of wind energy over a 20-year project life, the levelized value of the PTC to a wind project owner is approximately 2.1 cents per kilowatthour. Similarly, the lower value of the PTC for other resources could be expected to reduce the levelized cost of prime geothermal sites from 4.4 to 3.6 cents per kilowatthour, and to reduce the levelized cost of a new dedicated biomass plant burning low-cost eligible urban or agricultural waste from 5.1 to 4.5 cents per kilowatthour. Solar projects with high capital costs and relatively low capacity factors probably would benefit more from the available 10-percent investment tax credit than from the PTC (Table 22).

Figure 26. U.S. installed wind capacity, 1981-2003 (megawatts)



In the reference case, the projected levelized cost for electricity from new natural gas combined-cycle plants is 4.7 cents per kilowatthour, and for new coal-fired plants the projected cost in 2010 is 4.3 cents per kilowatthour [*109*]. The value of the incremental fuel and capacity displaced by wind power in 2010 is 4.3 cents per kilowatthour in the reference case. Thus, it is easy to see how the PTC could make wind plants an attractive investment in the mid-term electricity market.

In view of the history of past PTC extensions, another extension beyond the current 2005 expiration date seems well within the realm of possibility. Given the uncertainty regarding the long-term fate of the PTC, EIA examined one possible outcome for an extension of the PTC. The PTC extension case is not meant to represent any expectation about future policy decisions regarding the PTC, but rather to provide a useful indication of the impacts of the PTC program on future energy markets relative to the reference case forecast, which assumes no extension of the PTC beyond 2005. This case is based on an "as-is" extension to 2015 of the expanded renewable electricity PTC program, as expanded by the American Jobs Creation Act of 2004 to facilities placed in service by the end of 2015.

The current PTC law provides a tax credit of 1.8 cents per kilowatthour for the first 10 years of operation to new wind plants, dedicated biomass plants burning closed-loop fuel or poultry litter, and certain approved fossil fuel plants co-firing with closed-loop renewable fuels. A credit of 1.8 cents per kilowatthour is provided for the first 5 years of operation to new geothermal and solar plants [*110*], and a credit of 0.9 cent per kilowatthour is provided for the first 5 years of operation to new dedicated biomass plants burning a wide variety of "open-loop" fuels, such as urban wood wastes, landscaping wastes, agricultural residues, and forestry residues. Landfill gas and municipal solid waste mass-burn facilities are eligible for the "open-loop" credit as well, although this would preclude taking advantage of other tax credits offered to some of those facilities.

Table 22. Levelized costs of new conventional and renewable generation in two cases, 2010 (2003 cents per kilowatthour)

Generation source	*Reference case*	*PTC extension case*
Combined cycle	*4.7*	*4.5*
Combustion turbine	*7.0*	*6.8*
Coal	*4.3*	*4.3*
Geothermal	*4.4*	*3.6*
Photovoltaic	*21.0*	*21.0*
Solar thermal	*12.6*	*12.6*
Open-loop biomass	*5.1*	*4.5*
Wind	*4.8*	*2.9*
Avoided cost of geothermal or biomass	*4.4*	*4.0*
Avoided cost of wind	*4.3*	*4.0*

Each of the credits is modeled as specified in the law, with the exception of the "closed-loop" credits for dedicated biomass plants and approved co-firing applications, the tax credit for photovoltaics, and the credit for refined coal. Because of the long establishment times and relative expense of energy crops, it is assumed that there will be no dedicated, closed-loop biomass plants able to take advantage of an extension of the PTC to 2015. Furthermore, the eligibility of co-firing plants to take advantage of the credit is to be determined on a case-by-case basis by the Department of Energy, and determining which or how many plants will be able to qualify is beyond the scope of this analysis. This analysis assumes that no PTC is given for co-firing. Geothermal, utility-owned photovoltaics, and solar thermal power applications are all eligible for *either* the PTC or the ITC. In the case of photovoltaics, which has very high investment costs and relatively low annual output per unit capacity, the ITC is estimated to be the more valuable of the two tax credits, and it is assumed that it will be preferred over the PTC. EIA does not currently provide projections for refined coal markets.

The PTC extension case assumes an uninterrupted extension of the PTC through 2015. As indicated above, the PTC has historically been subject to a series of expirations with retroactive extension for short periods (typically, 2 years per extension). The resulting uncertainty for the relatively long-term cycle of electricity market investment may have a significant impact on the ability of the industry to exploit the subsidy. The observed "packing" of construction in the last 6 months or so of each new eligibility window may serve to increase investment cost. In addition, uncertainty about the future availability of the PTC may affect infrastructure investment decisions that could lead to fuller realization of cost-reduction opportunities [*111*].

In the PTC extension case, wind power has the largest projected gains, although landfill gas, geothermal, and dedicated, open-loop biomass resources all are projected to see some capacity expansion. Installed wind capacity in 2015 is almost 63 gigawatts in the PTC extension case, compared to 9.3 gigawatts in the reference case. This 580-percent increase in capacity

results in a 650-percent increase in generation from the reference case projection for 2015 (206 billion kilowatthours in the PTC extension case compared to 27 billion kilowatthours in the reference case).

In 2015, geothermal capacity in the PTC extension case (3.23 gigawatts) is more than 20 percent greater than in the reference case (2.66 gigawatts), resulting in 30 percent more electricity generation from geothermal resources in 2015 (Table 23). With limited availability of new sites, new landfill gas capacity in 2015 is only 50 megawatts greater in the PTC extension case than the reference case projection of 3,630 megawatts. Although new dedicated biomass capacity in 2015 is almost 65 percent greater in the PTC extension case than in the reference case (3.39 gigawatts compared to 2.06 gigawatts), total biomass generation in the electric power sector in 2015 is only 10 percent higher than in the reference case (33.13 billion kilowatthours compared to 30.01 billion kilowatthours). This is largely a result of a significant decline in the use of biomass for co-firing applications, as the dedicated plants receiving the tax credit generally are expected to have a competitive advantage over co-firing plants in obtaining open-loop fuel.

Although geothermal capacity and dedicated biomass capacity in the PTC extension case continue to grow after the assumed 2015 expiration of the PTC, wind capacity expansion all but stops when the PTC expires. Because geothermal and biomass compete as baseload resources, their relative economics in the 2015 to 2025 time frame are similar in the reference and PTC extension cases; however, both benefit from reduced technology costs as a result of "learning-by-doing." Wind, on the other hand, competes as an intermittent resource, with much of its generation displacing intermediate-load energy rather than peak or baseload energy. Initially, the displaced load consists of a significant amount of natural-gas-fired generation, with a relatively high fuel cost; however, after significant gas-fired generation is displaced, more coal-fired generation (with lower fuel costs) is displaced. In the PTC extension case, the avoided cost of wind generation is reduced by as much as 15 percent in 2020 from the reference case projection.

The total incremental cost to the U.S. Treasury of extending the PTC from 2005 to 2015 is estimated at $17 billion in lost tax revenue (all cumulative money calculations are in 2003 dollars, discounted at 7

Table 23. Renewable electricity capacity and generation in two cases, 2005, 2015, and 2025

	2005		2015		2025	
Projection	Reference case	PTC extension case	Reference case	PTC extension case	Reference case	PTC extension case
	Electric power sector net summer capacity (gigawatts)					
Conventional hydropower	78.1	78.1	78.2	78.2	78.2	78.2
Geothermal	2.2	2.2	2.7	3.2	4.6	5.3
Municipal solid waste	3.4	3.4	3.6	3.7	3.7	3.7
Wood and other biomass	1.8	1.8	2.1	3.4	4.5	5.6
Solar thermal	0.4	0.4	0.5	0.5	0.5	0.5
Solar photovoltaic	0.1	0.1	0.2	0.2	0.4	0.4
Wind	8.2	8.2	9.3	63.0	11.3	63.0
Total renewable	94.1	94.1	96.5	152.1	103.1	156.6
Total electric power industry	945	945	967	1,014	1,145	1,186
	Electric power sector generation (billion kilowatthours)					
Conventional hydropower	288.4	288.4	300.5	300.6	301.1	301.1
Geothermal	12.1	12.1	16.1	21.0	32.8	38.3
Municipal solid waste	24.3	24.3	26.1	26.5	26.5	26.9
Wood and other biomass	20.6	20.7	30.0	33.1	37.4	44.5
Dedicated plants	10.1	10.1	11.7	19.8	27.3	35.4
Co-firing	10.6	10.6	18.3	13.3	10.1	9.1
Solar thermal	0.7	0.7	0.9	0.9	1.0	1.0
Solar photovoltaic	0.1	0.1	0.5	0.5	1.0	1.0
Wind	23.6	23.6	27.3	205.7	34.5	205.7
Total renewable	369.8	369.8	401.4	588.3	434.2	618.5
Coal	2,054	2,054	2,305	2,275	2,890	2,802
Natural gas	699	699	1,172	1,054	1,403	1,331
Total net generation to the grid	3,890	3,890	4,676	4,708	5,522	5,545

percent per year unless otherwise noted). The electric power industry incurs $12 billion in cumulative additional costs through 2025 in the PTC extension case compared to the reference case; however, this additional expense is more than compensated for by the subsidy. Because the net effect of the PTC extension is a slight reduction in end-use electric power prices, electricity consumers save about $37 billion in end-use electricity expenditures through 2025 in the PTC extension case compared to reference case. In addition, the assumed PTC extension significantly reduces demand for natural gas in the electric power sector, lowering natural gas prices for all consumers. Total natural gas expenditures by consumers other than electric utilities are reduced by $13 billion through 2025 in the PTC extension case compared to the reference case. About $16 billion of the $17 billion in taxpayer cost is allocated to wind energy resources as a result of both the significantly higher level of PTC-induced wind generation and the higher PTC value and claim period for wind projects than for geothermal or open-loop biomass projects.

Distributed Generation in Buildings

Distributed generators installed by residential and commercial customers may supply electricity alone (generation) or electricity as well as heat or steam (CHP). On-site generators can have several advantages for electricity customers:

- If redundant capability is installed, reliability can be much higher than for grid-supplied electricity.
- Although electricity from distributed generation is generally more costly than grid-supplied power, the waste heat from on-site generation can be captured and used to offset energy requirements and costs for other end uses, such as space heating and water heating.
- Distributed generation can reduce the need for energy purchases during periods of peak demand, which can lower both current energy bills and, presumably, energy bills in future competitive markets, when peak prices will be set by the most expensive generator supplying power to the grid.

Currently, distributed generation provides a very small share of residential and commercial electricity requirements in the United States. The *AEO2005* reference case projects a significant increase in electricity generation in the buildings sector, but distributed generation is expected to remain a small contributor to the sector's energy needs. Although the advent of higher energy prices or more rapid improvement in technology could increase the use of distributed generation relative to the reference case projection, the vast majority of electricity used in buildings is projected to continue to be purchased from the grid.

The *AEO2005* buildings models represent several grid-connected distributed generation technologies either as simple generation or as CHP, including conventional technologies such as oil or gas engines and combustion turbines and new technologies such as solar photovoltaics (PV), fuel cells, and microturbines. PV systems are the most costly of the distributed technologies for buildings on the basis of installed capital costs; however, once the systems are installed, no fuel costs are incurred. Petroleum-based generation is often used for emergency power backup in the commercial sector, but potential issues related to localized emissions make it less appropriate than natural-gas-based generation for continuous operation.

The projected adoption of distributed generation technologies in the buildings sector is based on forecasts of the economic returns from their purchase to meet baseload electricity needs (also thermal needs in the case of CHP) and on estimated participation in programs aimed at fostering distributed generation [*112*]. A detailed cash flow analysis is used to estimate the number of years needed to achieve a positive cumulative cash flow. The calculations include the annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) from the investment over a 30-year period from the time of the investment decision. The analysis includes the assumption that if more electricity is generated than needed, the excess can be sold to the grid [*113*].

Economic penetration of these technologies is a function of how quickly an investment in a technology is estimated to recoup its flow of costs. Program-related purchases are based on estimates from the Department of Energy's Million Solar Roofs program, the Department of Defense fuel cell demonstration program, State RPS and other renewable energy programs and goals, and locally targeted initiatives, such as the Spire Solar Chicago program.

Table 24 shows projected installed capital costs [*114*] and electrical conversion efficiencies [*115*] for several of the distributed generation technologies represented in the buildings sector models. All fossil-fuel-fired systems are assumed to be used in CHP applications to take advantage of waste heat produced in the

generation process. The costs and performance of fossil-fuel-fired CHP and PV systems are assumed to improve over time in the *AEO2005* projections, with emerging technologies (fuel cells, microturbines, and PV) showing the most improvement. Technology learning is also expected to occur for the emerging technologies, allowing for additional cost declines if cumulative shipments increase sufficiently [*116*].

Market Factors

The availability of technologies does not guarantee their widespread adoption. Many factors enter into the decision whether to purchase grid-supplied electricity to meet all of a building's power needs or to invest in a distributed generation system. Some of the issues that affect the market for distributed generation are discussed below.

Economics, Technology, and Suitability. In most instances, purchasing electricity is currently more economical for residential and commercial consumers than investing in distributed generation systems. On average, buildings sector sites are much smaller than industrial sites, and they are limited to technologies that have been more expensive and less efficient than larger CHP. Commercial firms generally have fewer operating hours per year and lower load factors than industrial firms, limiting the annual hours of system operation in which the higher first costs can be recouped. In addition, few types of buildings applications involve the steady thermal requirements that maximize the efficiency and economics of CHP systems.

Recent increases in fuel prices have further dampened enthusiasm for new CHP systems in buildings. Although fuel costs are not an issue with PV systems, their high installed capital cost limits economic viability to areas with high electricity prices and/or program-based incentives that offset a significant portion of the added investment costs. To the extent that deregulated retail electricity markets may pass along hourly or seasonal variation in the cost of producing electricity, such as time-of-day or real-time pricing, distributed generation applications may see further economic opportunities to offset higher energy costs; however, the adoption of such rate structures on a widespread basis in the residential and commercial sectors is currently highly uncertain.

All the fossil-fuel-fired distributed generation technologies represented in the reference case are assumed to be CHP systems; however, based on a January 2000 report prepared by ONSITE SYCOM Energy Corporation, only about 5 percent of existing commercial buildings in the United States have technically adequate electric demand and thermal loads to meet the criteria for CHP [*117*]. Considering the possibility of cost-effective CHP systems in smaller sizes and the advent of systems that include heat-activated cooling [*118*] increases the potential market for CHP adoption, but conditions would need to change from those represented in the reference case to encompass a much larger share of the commercial sector, let alone to make CHP systems economically attractive to meet residential consumers' everyday power and heating needs.

The amount of electricity a PV system can produce depends on the quality of the solar resource, as well as the size and efficiency of the system. On an annual basis, a PV system in Alaska would, in general, produce less electricity than an identical system in Arizona. The suitability of PV also depends on the ability to site the system to take advantage of the sunlight available. In addition, although PV systems tend to generate power during some of the peak electricity demand hours, their value in offsetting peak power costs may be somewhat less than that of fossil-fueled systems, because their output cannot be controlled with sufficient precision to follow real-time pricing signals or match a time-of-day tariff structure.

Regulation. Another factor to be considered when an investment in distributed generation technology is being made is the regulatory environment. Requirements for permits and approvals for distributed generation systems vary widely by State, technology,

Table 24. Projected installed costs (2003 dollars per kilowatt) and electrical conversion efficiencies (percent) for distributed generation technologies by year and technology, 2004, 2010, 2020, 2025

	2004		2010		2020		2025	
Technology	*Cost*	*Efficiency*	*Cost*	*Efficiency*	*Cost*	*Efficiency*	*Cost*	*Efficiency*
Residential photovoltaic	8,600	14	6,200	18	3,814	22	3,180	22
Commercial photovoltaic	6,250	14	4,750	18	3,178	22	2,650	22
Commercial fuel cell	5,200	36	2,500	49	1,800	51	1,450	52
Natural gas turbine	1,860	22	1,679	24	1,567	27	1,539	28
Natural gas engine	1,130	32	1,030	33	930	34	915	34
Natural gas microturbine	1,773	28	1,415	36	870	38	818	39

fuel, and project size. Researching and responding to a wide range of requirements is a hurdle for project development, adding expense to an already capital-intensive endeavor. Requirements can range from emissions and siting regulations to local building, zoning, and fire codes to local utility interconnection policies, exit fees, and standby rates [*119*].

Interconnection. The electric grid was not designed for two-way energy flow or storing energy at the distribution level. Consequently, utilities have implemented interconnection policies for the safe and reliable operation of the local grid when distributed generation units are interconnected to it. Some States are proposing to follow the requirements recently set forth by the Institute of Electrical and Electronics Engineers in IEEE 1547, "Standard for Distributed Resource Interconnects with Electric Power Systems" [*120*]. Others are developing their own interconnection standards. Still others have no standards, and procedures in those States are defined by individual electric utilities. Although some utilities have simplified the processes for small distributed generation projects (below 30 to 40 kilowatts), utilities generally require an interconnection study to be completed as part of the planning process for an installation.

Emissions. Restrictions may also be imposed on emissions from fossil-fuel-fired on-site generation that could contribute to smog and acid rain. Basic permitting and emission control requirements vary by State and whether a site falls within an emissions nonattainment zone with significant air quality problems [*121*]. Most States do not require permits for small units or units with small amounts of emissions. The threshold for such exemptions varies by State. In addition, distributed generation equipment that requires a permit is likely to require some emission limitations or controls. Systems that use fuel oil typically have higher "fuel-based" emissions than those that run on natural gas, making permitting and control costs a larger issue for those systems.

Reference Case Projections

The *AEO2005* reference case includes residential and commercial distributed generation projections at the national level and for the nine Census divisions [*122*], using the assumptions and methodology described above. At the national level, there is currently little residential capacity for electricity generation from fossil fuels. Existing capacity consists primarily of emergency backup generators to provide electricity for minimum basic needs in the event of power outages. Generating capacity in the commercial sector is also primarily for emergency backup; however, some electricity supply and peak generation is reported. EIA's 1999 Commercial Buildings Energy Consumption Survey (CBECS) estimated that about 0.7 percent of all commercial buildings (1.6 percent of all commercial floorspace) use generators for purposes other than emergency backup.

Fossil-fuel-fired commercial generating facilities larger than 1 megawatt reported generating 7.0 billion kilowatthours of electricity in 2002 and 6.3 billion kilowatthours in 2003, about 0.5 percent of the sector's electricity needs [*123*]. The reference case projects an 80-percent increase in electricity supplied annually by fossil-fuel-fired distributed generation in the buildings sector, to 11.3 billion kilowatthours in 2025, but distributed generation still is expected to meet less than 1 percent of the electricity requirements for buildings nationally.

Generation from natural gas turbines at commercial facilities is projected to remain essentially constant throughout the forecast. Gas turbines are viewed as a "mature" technology that is expected to show only modest improvement over the forecast, and, in addition, few commercial facilities have power and thermal needs or operating hours that would warrant investment in a large CHP system such as a gas turbine. Although engines are expected to remain a popular choice for commercial CHP, the adoption of microturbines and fuel cells is projected to increase later in the forecast period, reflecting projected cost declines and technological progress for these emerging technologies. With reference case electricity and fossil fuel prices, the vast majority of residential consumers are not expected to purchase fossil-fuel-fired distributed generation systems to meet their daily electricity requirements.

The reference case projections for grid-connected PV incorporate current national incentives for commercial sector systems, including an Investment Energy Tax Credit and favorable depreciation treatment [*124*]. The effects of regional and local incentives are estimated through projections for program-related purchases of PV systems. Although *AEO2005* projections are limited to grid-connected systems, EIA estimates that remote PV applications (off-grid power systems) representing as much as 134 megawatts of electricity generation capacity were in service in 2002, in addition to another 362 megawatts of PV generating capacity in specialized applications, such as communications and transportation [*125*].

In the reference case, electricity generation from PV systems in the buildings sector is projected to increase at an average annual rate of 17 percent, to 3.7 billion kilowatthours in 2025 (Figure 27). New installations through 2010 are expected to result from program-related purchases that generally include incentives to help defray the high capital costs associated with the technology. Later in the forecast, as a result of projected cost declines combined with favorable tax treatment, PV systems are projected to become economically attractive without additional subsidies in regions where electricity costs are relatively high.

Delivered energy prices vary by geographical region in the United States and are expected to continue to differ by region throughout the forecast horizon. Variations in electricity prices, fossil fuel prices, and the relative difference between electricity and fossil fuel prices result in significant differences in the projected adoption of distributed generation technologies by region. Public policies and incentive programs differ by State and region as well, adding to the expected regional variation in distributed generation.

The use of fossil-fuel-fired distributed generation technologies in CHP applications is projected to grow fastest in regions with high electricity prices and relatively moderate natural gas prices (Figure 28). Although the Mountain Census division is projected to show the fastest rate of growth in the reference case, 5.0 percent per year between 2003 and 2025, the Pacific Census division is projected to show the greatest increase in generation, 1.6 billion kilowatthours. Census divisions with relatively low electricity prices, such as the East South Central division, show little growth.

Near-term adoption of PV systems in the buildings sector is expected to be concentrated in regions that exhibit some combination of the following: active programs to foster the development of PV, high electricity rates, and sufficient periods of sunlight to maintain PV electricity production. For example, in addition to abundant sunshine in many parts of California, the California Energy Commission's rebate program, funded by a System Benefits Charge, refunds up to one-half of the installed cost of PV systems. States with RPS programs that require a percentage of electricity generation to be provided from renewable energy sources often offer "extra credit" for PV that increases its attractiveness [*126*]. The Pacific Census division, the current leader in PV electricity generation, is expected to show the greatest increase in the *AEO2005* reference case, with projected PV generation of more than 1 billion kilowatthours in 2025 (Figure 28). In the New England and Middle Atlantic Census divisions, where high electricity prices are projected, the use of distributed PV systems is projected to increase by more than 20 percent from 2003 to 2025.

Alternative Cases

Technology Improvement. The buildings sector 2005 technology and high technology cases included in *AEO2005* examine the sensitivity of the projections to different technology assumptions in combination with reference case energy prices and economic assumptions [*127*]. These cases alter residential and commercial assumptions for distributed generation technologies, end-use equipment, and building shell measures, focusing only on technological progress in the buildings sector. In the 2005 technology case,

Figure 27. Projected buildings sector electricity generation by selected distributed resources in the reference case, 2003-2025 (billion kilowatthours)

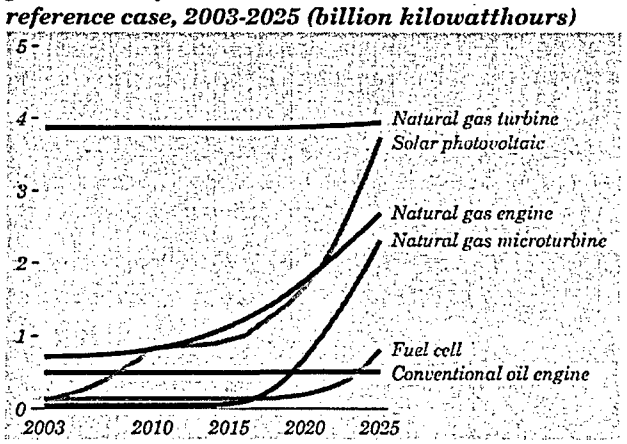
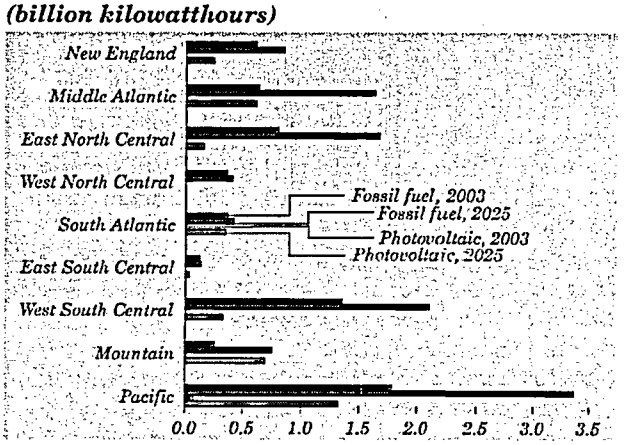


Figure 28. Projected buildings sector generation by fossil fuel-fired and photovoltaic systems by Census division in the reference case, 2003 and 2025 (billion kilowatthours)



which assumes no further technological improvements, fossil-fuel-fired CHP is projected to total 7.2 billion kilowatthours in 2025, a 14-percent increase from 2003 but 37 percent (4.2 billion kilowatthours) lower than the reference case projection (Table 25). Similarly, PV generation is projected to total 1.4 billion kilowatthours in 2025, 62 percent (2.3 billion kilowatthours) lower than reference case projection.

The buildings high technology case is based on more optimistic assumptions for emerging distributed generation technologies, allowing greater cost declines as shipments increase [*128*]. The high technology assumptions result in projected generation of 11.8 billion kilowatthours from fossil-fuel-fired CHP in 2025, 4 percent higher than the reference case projection. PV generation is projected to total 4.7 billion kilowatthours in 2025 in the high technology case, 25 percent higher that the reference case projection.

Energy Prices. In the *AEO2005* low world oil price case, lower prices for petroleum lead to lower projected electricity prices. As a result, more consumers are expected to purchase electricity rather than invest in distributed generation systems. In the low world oil price case, generation from fossil-fuel-fired CHP in buildings is projected to total 10.9 billion kilowatthours in 2025 (400 million kilowatthours less than in the reference case), and PV generation is projected to total 3.6 billion kilowatthours (100 million kilowatthours less than in the reference case)—both 4 percent lower than the corresponding reference case projections (Table 25). In the high world oil price case, projected electricity and natural gas prices are slightly higher than in the reference case for most of the forecast period. As a result, in 2025, generation from fossil-fuel-fired CHP in buildings is projected to total 11.8 billion kilowatthours, 4 percent (500 million kilowatthours) higher than the reference case projection, and PV generation is projected to total 3.9 billion kilowatthours, 4 percent (100 million kilowatthours) more than in the reference case.

Restricted Natural Gas Supply Case

The restricted natural gas supply case provides an analysis of the energy-economic implications of a scenario in which future gas supply is significantly more constrained than assumed in the reference case. Future natural gas supply conditions could be constrained because of problems with the construction and operation of large new energy projects, and because the future rate of technological progress could be significantly lower than the historical rate. Although the restricted natural gas supply case represents a plausible set of constraints on future natural gas supply, it is *not* intended to represent what is likely to happen in the future.

The restricted natural gas supply case assumes the following constraints on natural gas supply:

- The Alaska natural gas pipeline is not built and put into operation by 2025.
- No new U.S. regasification terminals for LNG are built during the forecast, but the proposed expansions of existing U.S. terminals are permitted to go into operation as currently scheduled, along with any new LNG terminals already under construction.
- The future rates of technological progress for oil and gas exploration and development for both conventional and unconventional gas are one-half of the historical rates assumed in the reference case.

The restricted supply case assumes that the Alaska natural gas pipeline is not built during the forecast period either because of public opposition to this project and/or a perception by potential project sponsors that there are significant risks associated with such a project that more than outweigh the potential rewards. Potential risks include the possibilities that pipeline construction costs could be significantly higher than currently estimated, and that future lower 48 natural gas prices could be considerably lower than either current prices or expected future prices.

The restricted supply case assumes that public opposition to the construction of new U.S. LNG regasification terminals would preclude their construction. Existing terminals are assumed to proceed with their expansion plans, based on the assumption that LNG operations at existing terminals have lower financial risk and are more acceptable to the public. Any new LNG terminals already under construction are assumed to be completed in the restricted supply

Table 25. Buildings sector distributed electricity generation in alternative cases: difference from the reference case in 2025 (billion kilowatthours)

Projection	*Fossil-fuel-fired generation*	*Photovoltaic generation*
Buildings 2005 technology case	*-4.2*	*-2.3*
Buildings high technology case	*0.5*	*0.9*
Low world oil price case	*-0.4*	*-0.1*
High world oil price case	*0.5*	*0.1*

case. In particular, Excelerate's EnergyBridge project in the Gulf of Mexico is under construction, in the sense that the LNG tankers are under construction, along with the docking buoy, which attaches the tanker to the pipeline. The Excelerate EnergyBridge project; the only new terminal represented in the restricted supply case, is assumed to become operational in 2006. The volume of LNG imported into Canada and Mexico is assumed to be identical in the restricted supply and reference cases.

The restricted supply case assumes limits on the degree to which technology could enhance the productivity of future oil and natural gas supply operations. For example, current technology permits producers to recover between 75 and 85 percent of the in-place gas in conventional expansion gas reservoirs. Clearly, the highest theoretical recovery is 100 percent. Similarly, while seismic technology to access underground geologic formations can still be improved, there could be diminishing economic returns to such advances, because it is unlikely that, even with such advances, seismic technology would be able to determine, for example, whether an adequate reservoir seal existed at the appropriate point in geologic time to permit the capture and retention of hydrocarbons.

Although the future rate of oil and gas technological progress might be considerably less than the historical rate, it is unlikely that there would be no technological progress in the future, given the competitive nature of the oil and gas business and continued private and public investment in research and development. Consequently, the restricted supply case assumes a rate of technological progress that is 50 percent lower than the historical rate. It is also assumed that the oil and gas industry in Canada would operate in the same technology environment as U.S. oil and gas producers. Consequently, the lower rate of technological improvement has the same impact on oil and gas exploration and development in Canada as in the United States.

Wellhead Natural Gas Prices. The assumptions used in the restricted natural gas supply case result in significantly higher projections of lower 48 wellhead natural gas prices. In 2015 and 2025, projected wellhead gas prices are 23 percent and 31 percent higher, respectively, in the restricted supply case than in the reference case (Figure 29). In 2015, the restricted supply case projects a wellhead price of $5.13 per thousand cubic feet (2003 dollars), compared with the reference case price of $4.16 per thousand cubic feet. Similarly, in 2025, the restricted supply case projects a wellhead price of $6.29 per thousand cubic feet, compared with the reference case price of $4.79 per thousand cubic feet.

Natural Gas Consumption. The high wellhead prices projected in the restricted supply case significantly reduce projected natural gas consumption (Figure 30). In the reference case, total U.S. natural gas consumption increases throughout the forecast, from 22.0 trillion cubic feet in 2003 to 30.7 trillion cubic feet in 2025. In the restricted supply case, total U.S. gas consumption grows from 2003 levels to a peak of 26.0 trillion cubic feet in 2014, then declines in the remainder of the forecast, to 24.5 trillion cubic feet in 2025.

All end-use sectors are projected to consume less natural gas in the restricted supply case. The electric power sector shows the greatest reduction in consumption because of the availability of other

Figure 29. Lower 48 average wellhead natural gas price in two cases, 2000-2025 (2003 dollars per thousand cubic feet)

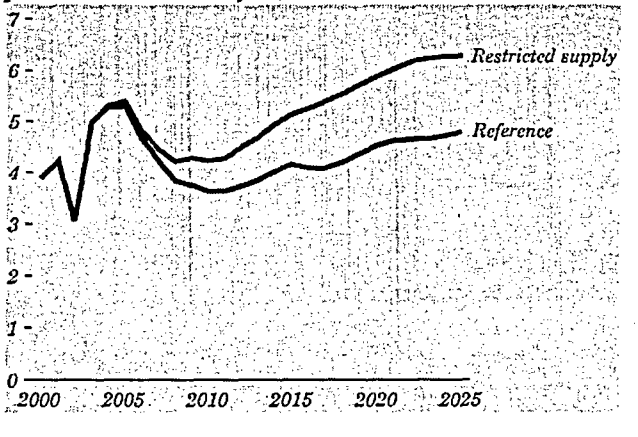
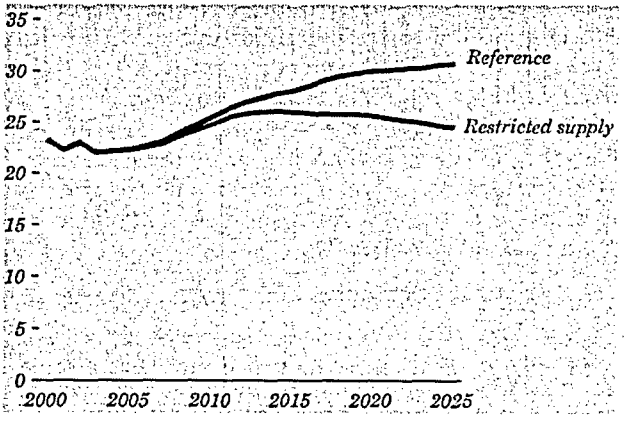


Figure 30. Total U.S. natural gas consumption in two cases, 2000-2025 (trillion cubic feet)



generating options. In 2025, projected natural gas consumption in the electric power sector is 4.3 trillion cubic feet lower in the restricted supply case than in the reference case (5.1 trillion cubic feet and 9.4 trillion cubic feet, respectively). The electric power sector accounts for almost 70 percent of the total reduction in projected gas consumption in 2025 in the restricted supply case and is largely responsible for the shape of the total gas consumption trend in that case (Figure 31). Specifically, natural gas consumption in the electric power sector is projected to peak in 2014 at 7.1 trillion cubic feet in the restricted supply case, then decline steadily to 5.1 trillion cubic feet in 2025.

The high natural gas prices in the restricted supply case both reduce the projected level of gas-fired electric generation capacity and reduce the use of the gas-fired generating plants already in operation. More coal-fired and renewable energy capacity is projected to be built as a result of the higher natural gas prices: 451 gigawatts of coal-fired capacity through 2025, as compared with 394 gigawatts in the reference case, and 114 gigawatts of renewable capacity in 2025, as compared with 103 gigawatts in the reference case.

The second largest decline in projected end-use natural gas consumption in the restricted supply case is in the industrial sector, with total projected consumption of 8.3 trillion cubic feet in 2025, as compared with 9.0 trillion cubic feet in the reference case. Industrial CHP production falls sharply as a result of the higher natural gas prices, from 123 billion kilowatthours in the reference case to 93 billion kilowatthours in the restricted supply case in 2025, which further reduces natural gas consumption.

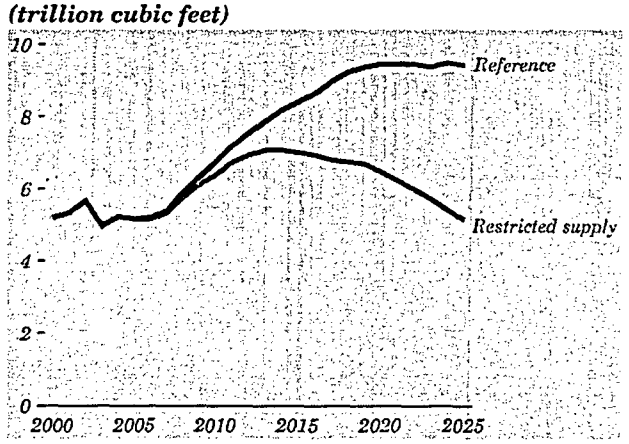
Projected natural gas consumption in the residential and commercial sectors is also reduced from reference case levels in the restricted supply case, again due to higher gas prices. Residential gas consumption in 2025 is projected to be 5.4 trillion cubic feet in the restricted supply case, compared with 6.0 trillion cubic feet in the reference case. Natural gas prices to residential consumers are 12 percent higher in the restricted supply case than in the reference case in 2015 and 19 percent higher in 2025, and residential electricity prices are 4 percent and 2 percent higher in 2015 and 2025, respectively.

Commercial gas consumption in 2025 is projected to be 3.8 trillion cubic feet in the restricted supply case, compared with 4.1 trillion cubic feet in the reference case. The higher natural gas prices in the restricted supply case prompt commercial consumers to invest in more efficient equipment or to switch to heating oil for their space heating and water heating needs, relative to the reference case. Commercial facilities also are expected to find natural-gas-fired CHP less attractive, with projected gas-fired electricity generation in the sector 17 percent (1.7 billion kilowatthours) lower in 2025 than projected in the reference case. Even with the actions described above, projected energy expenditures in the commercial sector in the restricted supply case are 5 percent higher than in the reference case in 2025, because the higher prices more than offset the reduced consumption volumes.

Natural Gas Supply. The supply of natural gas available to U.S. consumers comes from both domestic production and net imports. In the restricted natural gas supply case, the availability of future domestic gas production is constrained by the assumed absence of an Alaska natural gas pipeline and by rates of technological progress that are 50 percent lower than those observed historically. Natural gas imports are constrained by the assumption that only the currently scheduled proposed expansions of existing U.S. terminals are permitted to go into operation, along with new LNG terminals already under construction. Imports from Canada are constrained by the assumption of low rates progress in oil and gas exploration and recovery technologies.

The restricted supply case significantly reduces future LNG imports in comparison with the reference case projections (Figure 32). Net LNG imports in 2025 are projected to be 2.5 trillion cubic feet in the restricted supply case, compared with 6.4 trillion cubic feet in the reference case. Currently planned expansions at the four existing LNG terminals and

Figure 31. U.S. natural gas consumption for electric power generation in two cases, 2000-2025 (trillion cubic feet)



the construction and operation of the Excelerate EnergyBridge terminal are responsible for the increase in future LNG imports projected in the restricted supply case, relative to the 0.4 trillion cubic feet of net LNG imports in 2003. The restriction on new LNG terminals reduces LNG's share of total U.S. gas supply in 2025 from 21 percent in the reference case to 10 percent in the restricted supply case.

The higher natural gas prices projected in the restricted supply case have a mixed impact on net imports of natural gas from Canada. In the near term, the higher prices are projected to stimulate Canada's production, and from 2015 to 2020, U.S. imports of natural gas from Canada are projected to average about 340 billion cubic feet per year more in the restricted supply case than in the reference case. After 2020, a larger drop in net imports from Canada is projected in the restricted supply case than in the reference case, and projected net imports in 2025 are lower in the restricted supply case than in the reference case (2.3 trillion cubic feet and 2.5 trillion cubic, respectively).

With higher U.S. wellhead prices projected in the restricted supply case, Mexico is projected to become a net exporter of natural gas to the United States after 2019, rather than being a net importer as projected in the reference case. In 2025, net exports from Mexico to the United States are projected to be about 400 billion cubic feet of natural gas per year in the restricted supply case, compared with about 250 billion cubic feet per year of net imports from the United States in the reference case.

Total U.S. production of natural gas in 2025 is projected to be 19.1 trillion cubic feet in the restricted supply case, compared with 21.8 trillion cubic feet in the reference case (Figure 33). About 70 percent of the difference is directly attributable to the assumption that there would be no Alaska gas pipeline constructed in the restricted supply case.

In the lower 48 States, projected natural gas production is not significantly different in the restricted supply and reference cases, because the higher prices projected in the restricted supply case largely offset the lower assumed rate of technological progress. The restricted supply case projects total lower 48 gas production of 18.8 trillion cubic feet in 2025, 4 percent less than projected in the reference case. Most of the reduction in projected lower 48 conventional gas production—about 270 billion cubic feet in 2025 in the restricted supply case relative to the reference case—occurs offshore.

Unconventional gas production is sensitive to technological progress, because technological improvements could, for example, significantly improve the recovery rate of the unconventional gas in-place. Generally, there is more opportunity for technological progress to expand the economically recoverable unconventional resource base than the economically recoverable onshore conventional gas resource base. Offshore gas production is also sensitive to the future rate of technological progress, especially in the deepwater Gulf of Mexico. For example, technological improvements could reduce the development time necessary to bring oil and gas fields into operation and could make smaller oil and gas deposits profitable to produce.

Although projected lower 48 natural gas production in the restricted supply case is not significantly different from that in the reference case, the absence of an Alaska gas pipeline does reduce total U.S. gas

Figure 32. U.S. net imports of liquefied natural gas in two cases, 2000-2025 (trillion cubic feet)

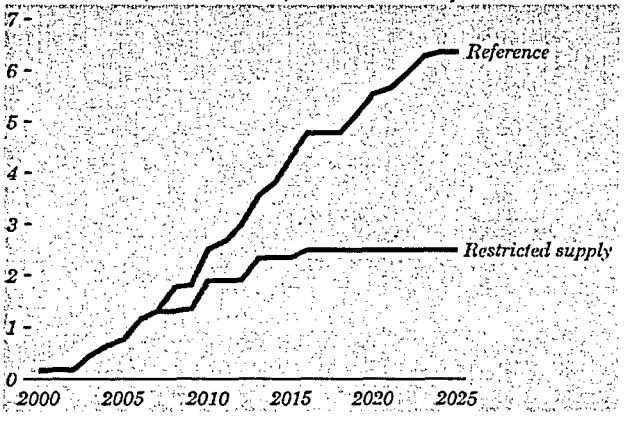
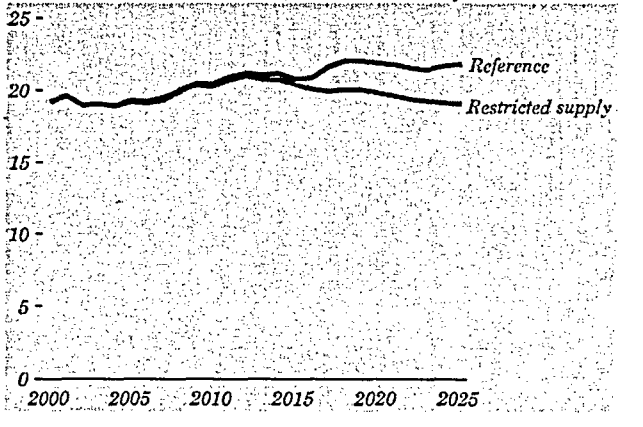


Figure 33. Total U.S. natural gas production in two cases, 2000-2025 (trillion cubic feet)

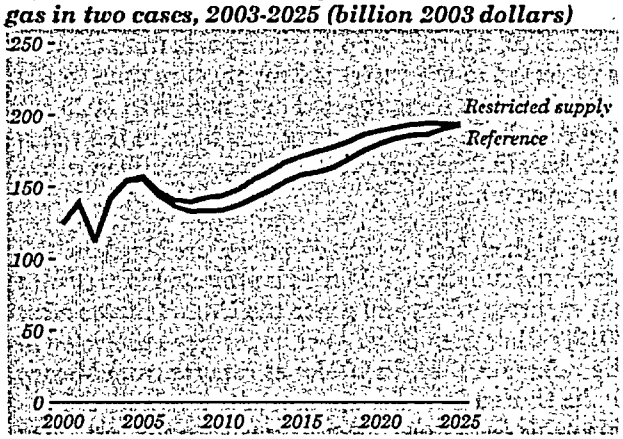


production throughout the forecast by 4 percent from 2003 through 2025. From an estimated technically recoverable natural gas resource base of 1,337 trillion cubic feet (as of January 1, 2003), 34 percent is projected to be produced in the restricted supply case, as compared with 36 percent in the reference case.

Electricity Prices and Consumption. In 2003, natural-gas-fired facilities provided 16 percent of the electricity generated in the United States. The reference case projects that gas-fired facilities will provide 25 percent of the electricity generated in 2025, compared with 14 percent in the restricted natural gas supply case. Because natural gas accounts for a significant portion of total electricity generation throughout the projections, higher natural gas prices increase future delivered electricity prices above those projected in the reference case. Although gas consumption in the electricity sector peaks in 2014 in the restricted supply case, the greatest difference in projections for the delivered price of electricity between the two cases is in 2018, when the price in the restricted supply case is 6 percent (0.4 cent per kilowatthour in 2003 dollars) higher than in the reference case.

Natural Gas Expenditures. The restricted natural gas supply case is projected to increase natural gas prices to a level that induces consumers to reduce their purchases of natural gas. Given the long lifetime of most gas-consuming equipment, the adjustment to higher gas prices would be relatively slow. Consequently, the negative impacts of high natural gas prices are more apparent in the nearer term than toward the end of the forecast. For example, the higher gas prices in the restricted supply case causes total projected U.S. end-use expenditures for natural gas to increase to $171 billion in 2015—equal to 1.1 percent of GDP—compared with $158 billion (1.0 percent of GDP) in the reference case (Figure 34). The greatest difference in gas consumption expenditures between the two cases, $13.4 billion, is projected in 2016. In 2025, when overall gas consumption is reduced in the restricted supply case, total end-use expenditures for natural gas are projected to be only $1.0 billion more than in the reference case.

Figure 34. Total end-use expenditures on natural gas in two cases, 2003-2025 (billion 2003 dollars)



Market Trends

The projections in the *Annual Energy Outlook 2005* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

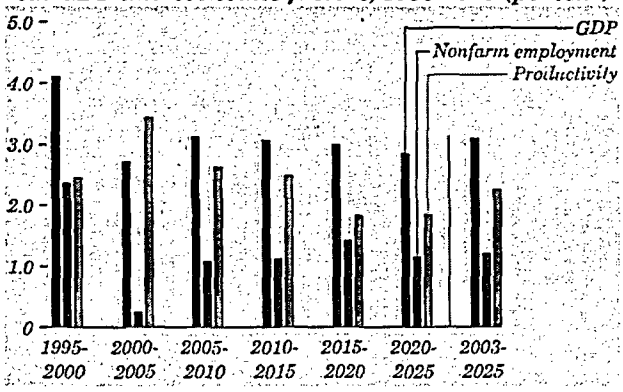
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of precision. Many key uncertainties in the *AEO2005* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

Strong Economic Growth Is Expected To Continue

Figure 35. Average annual growth rates of real GDP and economic factors, 1995-2025 (percent)



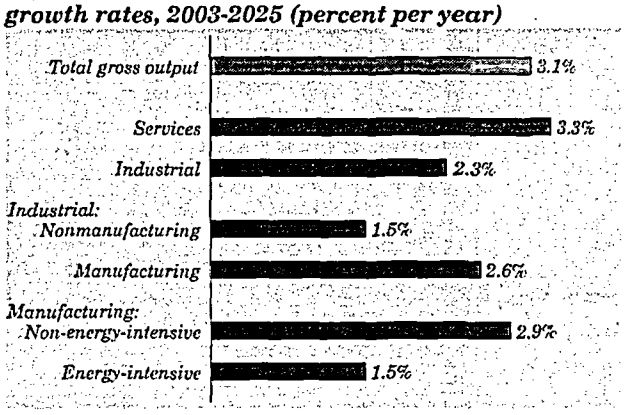
The output of the Nation's economy, measured by GDP, is projected to grow by 3.1 percent per year between 2003 and 2025 (with GDP based on 2000 chain-weighted dollars) (Figure 35). The labor force is projected to increase by 0.9 percent per year between 2003 and 2025. Labor productivity growth in the nonfarm business sector is projected at 2.2 percent per year.

Compared with the second half of the 1990s, the rates of growth in GDP and nonfarm employment were lower from 2000 through 2002. Economic growth has been more robust since 2003. Real GDP growth was 3.0 percent in 2003 and is expected to be 4.4 percent in 2004. The economy is expected to stabilize at its long-term growth path between 2005 and 2010. Total population growth (including armed forces overseas) is expected to remain fairly constant after 2003, growing by 0.8 percent per year on average. Labor force growth is expected to slow as a result of demographic changes, but more people over 65 are expected to remain in the work force. Nonfarm business productivity growth has been strong recently, averaging 3.8 percent per year from 2000 to 2003. Productivity growth from 2003 to 2025 is expected to average more than 2 percent per year, supported by investment growth of 5.1 percent per year.

From 2003 through 2025, disposable income is projected to grow by 3.1 percent per year and disposable income per capita by 2.2 percent per year. Nonfarm employment is projected to grow by 1.2 percent per year, and employment in manufacturing is projected to shrink by 0.6 percent per year.

Service Sectors Lead Output Growth, Industrial Output Growth Is Slower

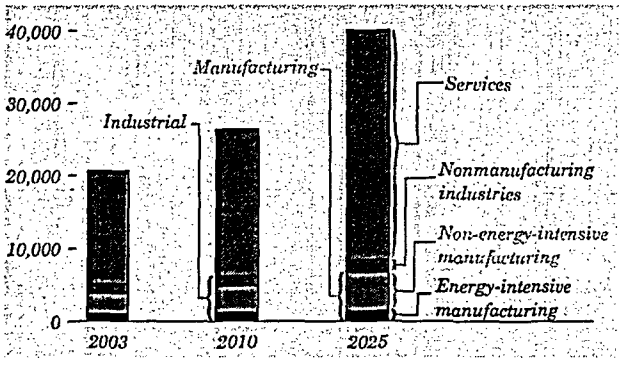
Figure 36. Sectoral composition of output growth rates, 2003-2025 (percent per year)



From 2003 to 2025, industrial output in real value terms is projected to grow by 2.3 percent per year, compared with 3.3-percent average annual growth in the services sector (Figure 36). Manufacturing output is projected to grow by 2.6 percent per year and nonmanufacturing output (agriculture, mining, and construction) by 1.5 percent per year. The energy-intensive manufacturing sectors [*129*] are expected to grow more slowly (1.5 percent a year) than the non-energy-intensive manufacturing sectors (2.9 percent per year).

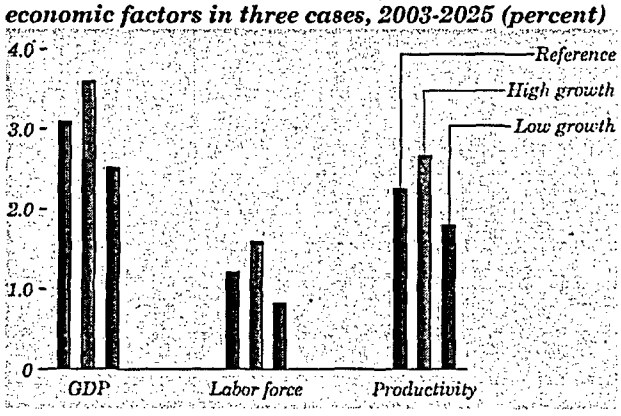
In *AEO2005*, the sectoral classification of the value of industrial output has been changed. In addition, the definition of services has been expanded to include the cost of goods in the wholesale and retail sectors. The industrial sector's share of total output is expected to fall from 25 percent in 2003 to 21 percent in 2025, and the manufacturing share of total output is projected to fall from 19 percent in 2003 to 17 percent in 2025 (Figure 37).

Figure 37. Sectoral composition of gross output, 2003, 2010, and 2025 (billion 1996 dollars)



High and Low Growth Cases Reflect Uncertainty of Economic Growth

Figure 38. Average annual real growth rates of economic factors in three cases, 2003-2025 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO2005* includes high and low economic growth cases in addition to the reference case (Figure 38). The high and low growth cases are intended to show the projected effects of alternative growth assumptions on energy markets. Economic variables in the alternative cases—including GDP and its components, disposable income, interest rates, productivity, population, prices, wages, and employment—are modified, in a consistent framework, from those in the reference case.

The high economic growth case assumes higher projected growth rates for population (1.0 percent per year), nonfarm employment (1.6 percent per year), and productivity (2.7 percent per year) from 2003 through 2025. With higher productivity gains and employment growth, inflation and interest rates are projected to be lower than in the reference case, and economic output is projected to grow at a higher rate (3.6 percent per year) than in the reference case (3.1 percent). GDP per capita is expected to grow by 2.5 percent per year, compared with 2.2 percent in the reference case.

The low economic growth case assumes lower growth rates for population (0.6 percent per year), nonfarm employment (0.8 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the low growth case, economic output is projected to increase by 2.5 percent per year from 2003 through 2025, and growth in GDP per capita is projected to average only 1.9 percent per year.

Long-Run Trend Shows U.S. Economic Growth of About 3 Percent per Year

Figure 39. Average annual real GDP growth rate, 1970-2025 (percent, 22-year moving average)

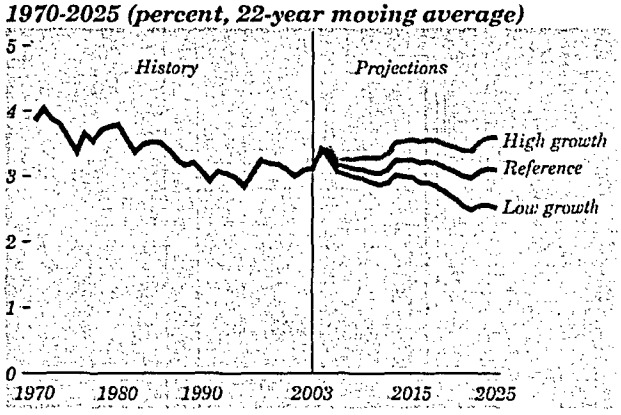
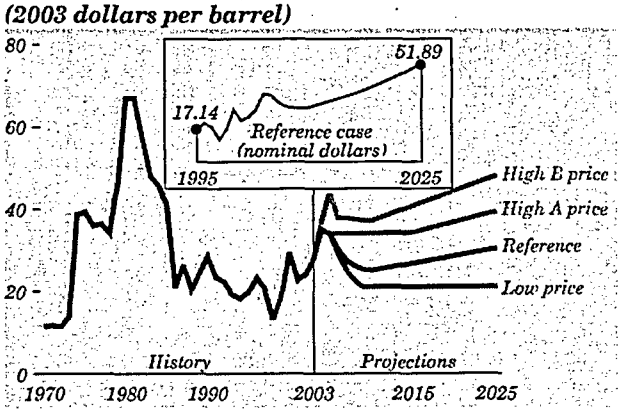


Figure 39 shows the trend in the 22-year moving average annual real growth rate for GDP, including projections for the three *AEO2005* cases. The value for each year is calculated as the annual compound growth rate over the preceding 22 years. The 22-year average shows major long-term trends in GDP growth by smoothing out the more volatile year-to-year changes (although periods that start or end in recession years can show more volatile changes in the growth rate). Annual real GDP growth has fluctuated considerably around the trend. The high and low growth cases capture the possibility of different paths for long-term output growth.

One reason for the variability of the forecasts is the composition of economic output, reflected by real growth rates of consumption and investment relative to overall GDP growth over the 2003-2025 period. In the reference case, consumption is projected to grow by 2.7 percent per year, while investment grows at a 5.1-percent annual rate. In the high growth case, with relatively lower interest rates, growth in investment is projected to average 5.8 percent per year. Higher investment rates lead to faster capital accumulation and higher productivity gains, which, combined with higher labor force growth, yield higher aggregate economic growth than projected in the reference case. In the low growth case, with relatively higher interest rates, annual growth in investment expenditures is projected to average only 4.0 percent. Lower investment growth rates imply slower capital accumulation. With the labor force also growing more slowly, aggregate economic growth is expected to be significantly lower than projected in the reference case.

Projections Vary in Cases With Different Oil Price Assumptions

Figure 40. World oil prices in four cases, 1970-2025 (2003 dollars per barrel)

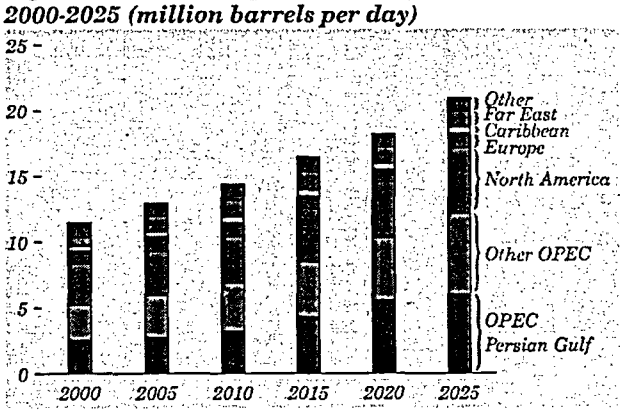


The historical record shows substantial variability in world oil prices, and there is similar uncertainty about future prices. Four *AEO2005* cases with different price paths allow an assessment of alternative views on the future of oil prices (Figure 40). In the reference case, with both OPEC and non-OPEC producers scheduled to add new production capacity over the next 5 years, prices in 2010 are projected to be more than $10 per barrel lower than current prices (all prices in 2003 dollars per barrel). After 2010, oil prices are projected to rise by about 1.3 percent per year, to more than $30 per barrel in 2025. (In nominal dollars, the reference case price is about $52 in 2025.) In the low price case, prices are projected to decline from their high in 2004 to $21 per barrel in 2009 and to remain at that level out to 2025. The high A price case projects that prices will remain at about $34 through 2015 and then increase on average by 1.4 percent per year, to more than $39 per barrel in 2025. In the high B case, world oil prices are projected to fall from current levels to $37 per barrel in 2010 and then rise to $48 per barrel in 2025.

Projected prices in all four cases are higher than in *AEO2004* [*130*], reflecting recent improved production discipline by OPEC members and limited ability of other producers to expand production despite increasing demand and high utilization rates that have led to higher prices. The price projections in the high A and B cases are sufficiently robust to encourage greater market penetration of alternative energy supplies.

Oil Imports Reach More Than 20 Million Barrels per Day by 2025

Figure 41. U.S. gross petroleum imports by source, 2000-2025 (million barrels per day)



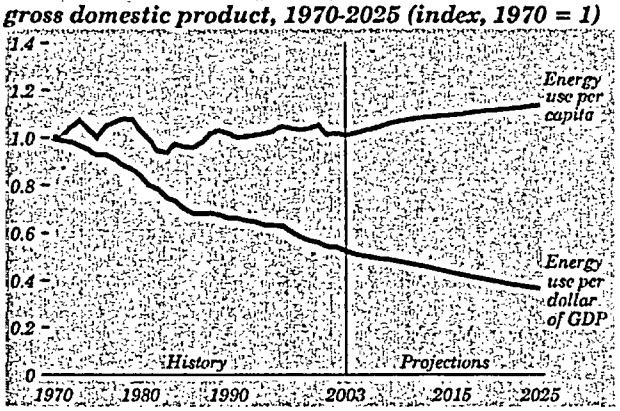
Total U.S. gross petroleum imports are projected to increase in the reference case from 12.3 million barrels per day in 2003 to 20.2 million in 2025 (Figure 41). Crude oil accounts for most of the increase in imports, because distillation capacity at U.S. refineries is expected to be more than 5.5 million barrels per day higher in 2025 than it was in 2003. Gross imports of refined petroleum, including refined products, unfinished oils, and blending components, are expected to increase by almost 60 percent from 2003 to 2025.

Crude oil imports from the North Sea are projected to decline gradually as North Sea production ebbs. Significant imports of petroleum from Canada and Mexico are expected to continue, with much of the Canadian contribution coming from the development of its enormous oil sands resource base. West Coast refiners are expected to import small volumes of crude oil from the Far East to replace the declining production of Alaskan crude oil. The Persian Gulf share of total gross petroleum imports, 20.4 percent in 2003, is expected to increase to almost 30 percent in 2025; and the OPEC share of total gross imports, which was 42.1 percent in 2003, is expected to be above 60 percent in 2025.

Most of the increase in refined product imports is projected to come from refiners in the Caribbean Basin, North Africa, and the Middle East, where refining capacity is expected to expand significantly. Vigorous growth in demand for lighter petroleum products in developing countries means that U.S. refiners are likely to import smaller volumes of light, low-sulfur crude oils.

Average Energy Use per Person Increases in the Forecast

Figure 42. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)



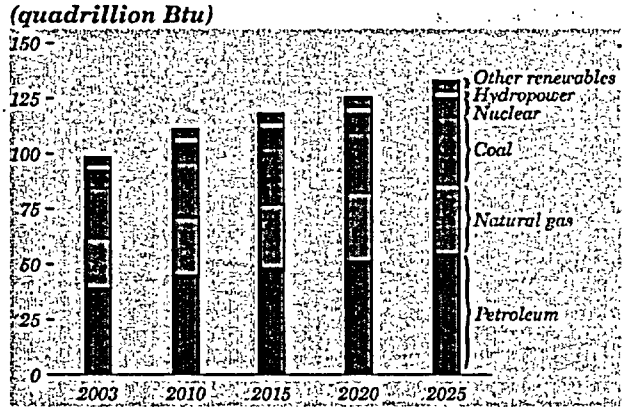
Energy intensity, as measured by energy use per 2000 dollar of GDP, is projected to decline at an average annual rate of 1.6 percent, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 42). The projected rate of decline falls between the average rate of 2.3 percent from 1970 through 1986, when energy prices increased in real terms, and the 0.7-percent rate from 1986 through 1992, when energy prices were generally falling. Since 1992, energy intensity has declined on average by 1.9 percent per year.

During the late 1970s and early 1980s, energy consumption per capita fell in response to high energy prices and weak economic growth. From the late 1980s through the mid-1990s, with declining energy prices and strong economic growth, per capita energy use increased. Since the mid-1990s, energy consumption per capita has declined in some years and increased in others. Per capita energy use is projected to increase in the *AEO2005* forecast at an average annual rate of 0.5 percent, with growth in demand for energy services only partially offset by efficiency gains.

The potential for more energy conservation has received increased attention recently as energy prices have risen. *AEO2005* does not assume policy-induced conservation measures beyond those in existing legislation and regulation, nor does it assume behavioral changes that could result in greater energy conversation, beyond those experienced in the past.

Petroleum and Natural Gas Lead Increases in Primary Energy Use

Figure 43. Primary energy use by fuel, 2003-2025 (quadrillion Btu)



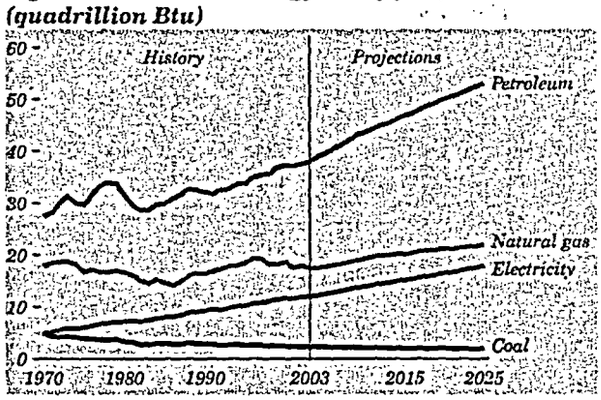
Total primary energy consumption, both in the end-use sectors and for electric power generation, is projected to grow from 98.2 quadrillion Btu in 2003 to 133.2 quadrillion Btu in 2025 (Figure 43). Petroleum consumption increases from 39.1 quadrillion Btu in 2003 to 54.4 quadrillion Btu in 2025, with about 80 percent of the increase expected in fuel use for transportation and the remainder in the industrial, commercial, and electricity generation sectors.

Natural gas consumption grows from 22.5 quadrillion Btu in 2003 to 31.5 quadrillion Btu in 2025. Over 50 percent of the expected increase is for electric power generation. Although some growth in other uses is also expected, particularly for industrial applications, their share of total natural gas use is projected to decline as a result of strong growth in demand in the electricity generation sector. Electricity generation is also expected to account for most of the growth in coal consumption, from 22.7 quadrillion Btu in 2003 to 30.5 quadrillion Btu in 2025. Much of the increase is expected after 2010, when higher natural gas prices make coal a more competitive fuel for power plants.

Smaller increases are projected for nuclear energy and primary renewable energy consumption. No new nuclear facilities are projected to be built before 2025, but higher capacity factors at existing plants lead to an expected increase from 8.0 quadrillion Btu in 2003 to 8.7 quadrillion Btu in 2025. Use of renewable energy from nonhydropower sources is projected to grow from 3.4 quadrillion Btu in 2003 to 5.4 quadrillion Btu in 2025 as a result of State mandates for renewable electricity generation, higher natural gas prices, and renewable energy production tax credits.

Petroleum and Electricity Lead Growth in Energy Consumption

Figure 44. Delivered energy use by fuel, 1970-2025 (quadrillion Btu)



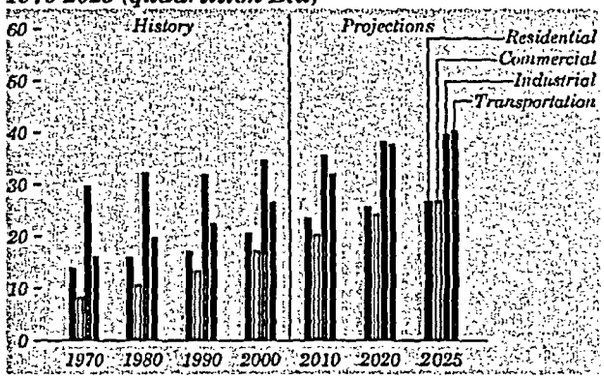
Consumption of petroleum products, mainly for transportation, makes up the largest share of delivered energy use in the residential, commercial, industrial, and transportation sectors in the *AEO2005* forecast (Figure 44). Total delivered energy use (excluding energy used for generation in the electric power sector) grows by 1.5 percent per year on average from 2003 to 2025, and transportation sector energy use grows by 1.8 percent per year. Transportation use grew by 2.0 percent per year in the 1970s and more slowly in the 1980s as a result of rising fuel prices and new Federal fuel economy standards. Stable fuel prices and a lack of new fuel economy standards are expected to reduce fuel economy gains in the forecast, while population growth and more travel per capita increase demand for gasoline.

Growth in delivered electricity consumption is slowed by efficiency improvements and by market saturation of end uses such as air conditioning in some regional markets.

Natural gas use is projected to grow at a slower rate than overall delivered energy demand, in contrast to its more rapid growth during the 1990s. As a result, natural gas is expected to meet 22 percent of total end-use energy requirements in 2025, compared with 24 percent in 2003. End-use demand for energy from renewables such as wood and ethanol is projected to grow by 1.2 percent per year as a result of continued competition from traditional purchased fuels.

U.S. Primary Energy Use Exceeds 133 Quadrillion Btu per Year by 2025

Figure 45. Primary energy consumption by sector, 1970-2025 (quadrillion Btu)



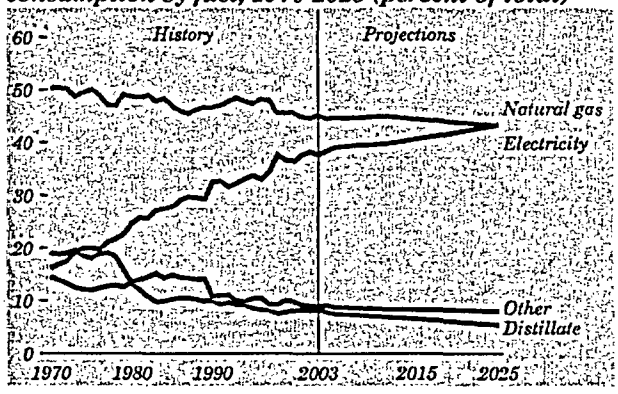
Primary energy use in 2025 (including electricity generation losses) is projected to be 133.2 quadrillion Btu in 2025 in the reference case, 36 percent higher than in 2003 (Figure 45). In the early 1980s energy prices rose, and sectoral energy consumption grew relatively little. After the early 1980s, however, declining real energy prices contributed to a marked increase in energy consumption. With higher energy prices since the late 1990s, energy consumption has again slowed.

Primary energy demand in the residential sector is projected to grow at one-third the expected growth rate for GDP and in the commercial sector at almost two-thirds the GDP growth rate. Demand for energy is expected to grow more rapidly in the transportation sector than in the buildings sectors as a result of increased per capita travel and slower fuel efficiency gains. Assumed efficiency gains, higher real energy prices, and structural shifts between industries are projected to cause industrial demand for primary energy to grow more slowly than GDP.

To bracket the uncertainty inherent in any long-term forecast, alternative cases were used to highlight the sensitivity of the forecast to different oil price and economic growth paths. At the consumer level, oil prices primarily affect the demand for transportation fuels. Projected oil use for transportation in the high A world oil price case is 5.8 percent lower than in the low world oil price case in 2025, as consumer choices favor more fuel-efficient vehicles and the demand for travel services is reduced slightly. For 2025, the projection of transportation energy use in the high economic growth case is 13.2 percent greater than in the low economic growth case.

Electricity Share Expected To Match Natural Gas in Residential Energy Use

Figure 46. Residential delivered energy consumption by fuel, 1970-2025 (percent of total)



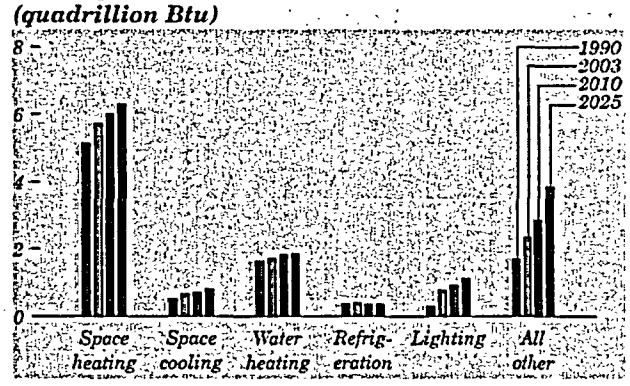
Residential delivered energy use is projected to increase by 23 percent between 2003 and 2025 (9 percent by 2010). Most (68 percent) of the growth results from increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, is an important component of the national trend, along with the penetration of consumer electronics, such as home office equipment and security systems (Figure 46).

Natural gas use in the residential sector is projected to grow by 1.1 percent per year from 2003 to 2010 and 0.6 percent per year from 2010 to 2025 while losing share in residential delivered energy consumption. Average natural gas prices from 2003 to 2025 are projected to be 14 percent below 2004 prices (7 percent below 2003), remaining competitive with heating oil. The number of homes heated with natural gas is projected to increase by more than the number heated with electricity or oil. Distillate use is projected to fall by 19 percent between 2003 and 2025, as energy efficiency gains outpace the increase in the number of homes using oil for space heating applications.

Newly built homes today are, on average, 13 percent larger than the existing housing stock, with correspondingly greater needs for heating, cooling, and lighting. Under current building codes and appliance standards, however, energy use per square foot is typically lower for new construction than for the existing stock. Further reductions in residential energy use per square foot could result from additional gains in equipment efficiency and more stringent building codes, requiring more insulation, better windows, and more efficient building designs.

Efficiency Standards Moderate Residential Energy Use

Figure 47. Residential delivered energy consumption by end use, 1990, 2003, 2010, and 2025 (quadrillion Btu)



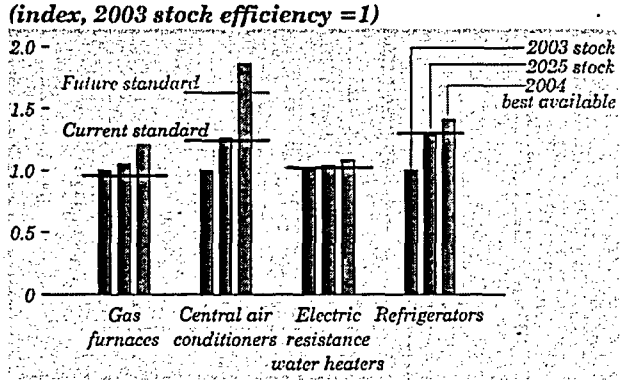
Delivered energy use for space heating grew by 0.8 percent per year from 1990 to 2003 (Figure 47). Future growth is expected to be slowed by higher equipment efficiency and more stringent building codes. Gains in building shell efficiency are projected to reduce demand for space heating per household by about 7 percent in 2010 and 16 percent in 2025 relative to 2003; however, those improvements are offset to a degree by better accounting of additions to existing homes and by the increased height of ceilings in new homes.

A variety of appliances are now subject to minimum efficiency standards, including heat pumps, air conditioners, furnaces, refrigerators, and water heaters. Current (July 2001) standards for a typical residential refrigerator limit electricity use to 510 kilowatthours per year. Energy use for refrigeration is projected to decline by 1.4 percent per year from 2003 to 2010 and 0.5 percent per year to 2025 as older refrigerators are replaced with new models. With no new standards for refrigerators assumed in the forecast, the decline slows when large numbers of the older, less efficient units have been replaced.

The "all other" category, which accounted for 20 percent of residential delivered energy use in 2003, is projected to account for 27 percent in 2025. Voluntary programs, both within and outside the appliance industry, are expected to forestall even larger increases. At annual rates of 2.9 percent from 2003 to 2010 and 2.3 percent from 2003 to 2025, growth in the "all other" demand category is projected to exceed the growth rates of other components through 2025.

Available Technologies Can Slow Growth in Residential Energy Use

Figure 48. Efficiency indicators for selected residential appliances, 2003 and 2025 (index, 2003 stock efficiency =1)

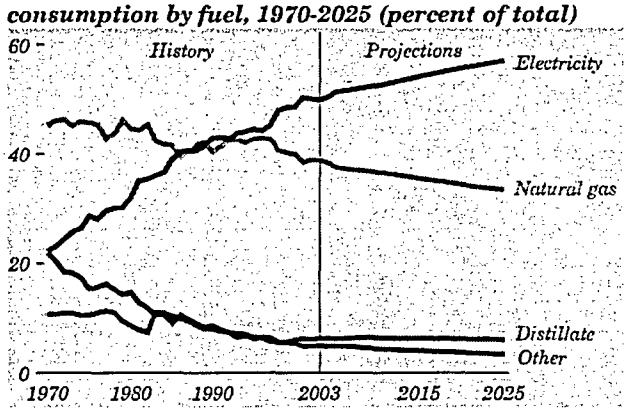


The *AEO2005* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act of 1987, the most recent Federal efficiency standards are higher than the 2003 stock, ensuring an increase in stock efficiency (Figure 48) without any additional new standards. Future updates to the Federal standards could have a significant effect on residential energy consumption, but they are not included in the reference case. The new efficiency standards for water heaters, clothes washers, central air conditioners, and heat pumps that were announced in January 2001 are included in the reference case.

For almost all end-use services, existing technologies can significantly curtail future energy demand if they are purchased by consumers. The most efficient technologies can provide significant long-run savings in energy bills, but their higher purchase costs (and in some cases, unsuitability for retrofit applications) tend to restrict their market penetration. For example, condensing technology for natural gas furnaces, which reclaims heat from exhaust gases, can raise efficiency by more than 20 percent over units that just meet the current standard; and variable-speed scroll compressors for air conditioners and refrigerators can increase their efficiency by 50 percent or more. In contrast, there is little room for efficiency improvements in electric resistance water heaters, because the technology is approaching its thermal limit.

Electricity Share of Commercial Energy Use Is Expected To Increase

Figure 49. Commercial delivered energy consumption by fuel, 1970-2025 (percent of total)

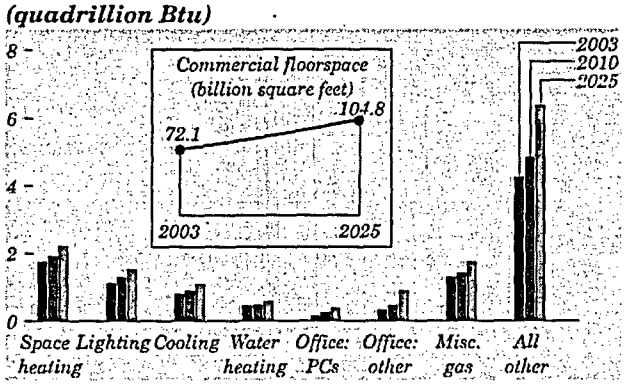


Recent trends in commercial sector fuel shares are expected to continue, with growth in overall consumption similar to its pace over the past two decades (Figure 49). Commercial delivered energy use (excluding primary energy losses in electricity generation) is projected to grow by 1.9 percent per year between 2003 and 2025, slightly faster than the projected growth rate for commercial floorspace of 1.7 percent. Energy consumption per square foot is projected to show little increase, with efficiency standards, voluntary government programs aimed at improving efficiency, and other technology improvements expected to balance the effects of a projected increase in demand for electricity-based services and a slow rise in energy prices after 2010.

Electricity accounted for 50 percent of commercial delivered energy consumption in 2003, and its share is projected to increase to 57 percent in 2025. Expected efficiency gains in electric equipment are projected to be offset by the continuing penetration of new technologies and greater use of office equipment. Natural gas, which accounted for 39 percent of commercial energy consumption in 2003, is projected to decline to a 33-percent share by the end of the forecast. Distillate fuel oil, which accounted for 10 percent of commercial demand in the years before deregulation of the natural gas industry, made up only 6 percent of commercial energy demand in 2003. The distillate fuel share is projected to remain at 6 percent in 2025, as fuel oil continues to compete with natural gas for space and water heating uses. With conventional fuel prices projected to increase only slowly, no appreciable growth in the share of renewable energy in the commercial sector is anticipated.

Commercial Efficiency Gains Are Not Expected To Balance Demand

Figure 50. Commercial delivered energy consumption by end use, 2003, 2010, and 2025 (quadrillion Btu)

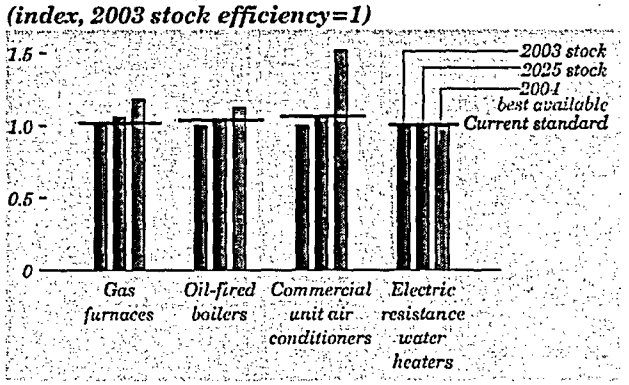


Energy use for the major commercial end uses is projected to increase slightly, as growth in requirements outpaces the adoption of more energy-efficient equipment. Minimum efficiency standards, which contribute to projected efficiency improvements in space heating, space cooling, water heating, and lighting, moderate the expected growth in overall commercial energy demand. A projected increase in building shell efficiency, which affects the energy required for space heating and cooling, contributes to the trend (Figure 50).

The highest growth rates are expected for end uses that have not yet saturated the commercial market. Energy use for personal computers is projected to grow by 4.5 percent per year and for other office equipment, such as copiers, fax machines, and larger computers, by 4.8 percent per year through 2025. The growth in electricity use for office equipment reflects a trend toward more powerful equipment, increases in the market for commercial electronic equipment, and, while electricity prices fluctuate somewhat (declining between 2005 and 2011 and increasing later), generally low real electricity prices. Natural gas use for such miscellaneous uses as cooking and self-generated electricity is expected to grow by 1.4 percent per year. New telecommunications technologies and medical imaging equipment are projected to increase electricity demand in the "all other" end-use category, which also includes ventilation, refrigeration, minor fuel consumption, and energy use for a myriad of other uses, such as municipal water services, service station equipment, elevators, and vending machines. Annual growth of 1.9 percent is expected for the "all other" category.

Current Technologies Provide Potential Energy Savings

Figure 51. Efficiency indicators for selected commercial equipment, 2003 and 2025 (index, 2003 stock efficiency=1)

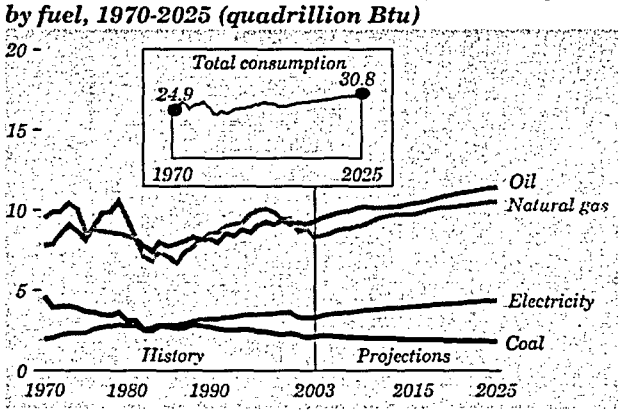


The stock efficiency of energy-using equipment in the commercial sector, as illustrated by the index shown in Figure 51, is projected to increase in the *AEO2005* reference case. As equipment is replaced and new buildings are built, technology advances are expected to reduce commercial energy intensity in most end-use services, although the long equipment service lives for many technologies moderate the pace of efficiency improvement in the forecast. For the majority of equipment covered by the Energy Policy Act of 1992, the existing Federal efficiency standards are higher than the average efficiency of the 2003 stock, ensuring some increase in the stock average efficiency as new equipment is added. A variety of commercial technologies, such as air-cooled air conditioners and gas-fired boilers, are currently being considered for more stringent standards. Future updates to the Federal standards could have significant effects on commercial energy consumption, but they are not included in the reference case.

Currently available technologies have the potential to reduce commercial energy consumption significantly. Improved heat exchangers for oil-fired boilers can raise efficiency by 8 percent over the current standard; and the use of multiple compressors and enhanced heat exchanger surfaces can increase the efficiency of unit air conditioners by more than 50 percent. When a business is considering an equipment purchase, however, the additional capital investment required for the most efficient technologies often carries more weight than do future energy savings, limiting the adoption of more efficient technologies.

Industrial Energy Use Could Grow by 24 Percent by 2025

Figure 52. Industrial delivered energy consumption by fuel, 1970-2025 (quadrillion Btu)

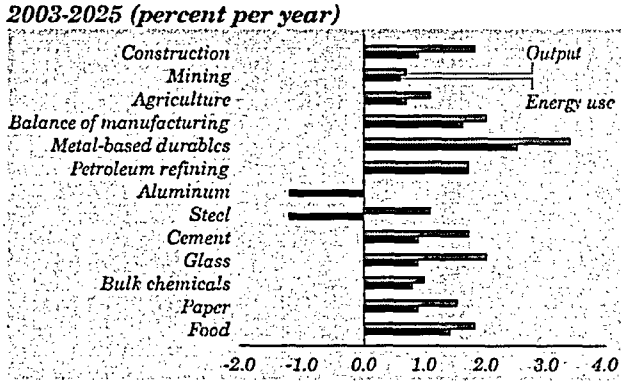


Industrial sector delivered energy consumption increased from 24.5 quadrillion Btu in 1990 to 26.4 quadrillion Btu in 2000, but economic recession in 2001 and rising natural gas prices had reduced industrial energy use to 24.9 quadrillion Btu in 2003. Natural gas use fell by 1.1 quadrillion Btu, accounting for most of the decline. With high natural gas prices expected to continue, industrial use is not projected to surpass its 1997 peak until after 2020.

Delivered energy use in the industrial sector (including agriculture, mining, construction, and traditional manufacturing) is projected to increase by 1.0 percent per year from 2003 to 2025 (Figure 52). Electricity (for machine drive and some production processes) and natural gas are the major energy sources used for heat and power in the industrial sector. Industrial use of purchased electricity is projected to increase by 1.3 percent per year from 2003 to 2025. Delivered natural gas prices in the industrial sector in 2025 are projected to be lower than in 2004; consequently, industrial natural gas use is expected to increase by 1.1 percent per year from 2003 to 2025. Petroleum use in the industrial sector is projected to grow by 1.0 percent per year from 2003 to 2025, whereas coal use is expected to decline by 0.6 percent per year as new steelmaking technologies continue to reduce demand for metallurgical coal. Coal use for boiler fuel is expected to remain essentially flat. Renewable energy (predominantly biomass) is the fastest growing industrial fuel in the forecast at a rate of 1.5 percent per year, but its share of the sector's delivered energy use remains small, at 8 percent in 2025.

Energy-Intensive Industries Grow Less Rapidly Than Industrial Average

Figure 53. Average growth in manufacturing output and delivered energy consumption by sector, 2003-2025 (percent per year)

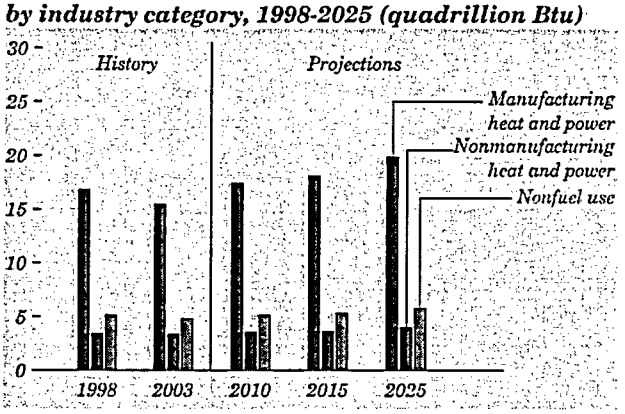


In *AEO2005*, industrial output is based on the North American Industry Classification System rather than the Standard Industrial Classification used in previous *AEO*s. The new classifications reduce manufacturing output by 3 percent in 1997 and lead to reduction in the historical growth rates for some industries. In the *AEO2005* forecast, industrial output grows at an average rate of 2.3 percent per year from 2003 to 2025, and growth in output growth varies widely by industry, from no growth in the aluminum industry to 3.4 percent in the metal-based durables industry (Figure 53). Metal-based durables, including fabricated metal products, machinery, electronic and electric products, and transportation equipment, accounted for one-third of industrial output in 2003.

Energy consumption growth also varies widely among specific industries. For example, the steel industry is expected to rely increasingly on scrap-based steelmaking techniques with lower energy requirements, and the aluminum industry is assumed to add no new primary smelting capacity, which is the most energy-intensive component of aluminum manufacturing. Relatively low output growth is also projected for both steel and aluminum, and as a result, energy consumption in both the steel and aluminum industries is projected to decline. The metal-based durables industry is projected to have the most rapid growth in energy consumption, at 2.5 percent per year, but its energy use accounts for only 7 percent of all industrial energy consumption in 2025.

Industrial Energy Use Grows Steadily in the Projections

Figure 54. Industrial delivered energy consumption by industry category, 1998-2025 (quadrillion Btu)



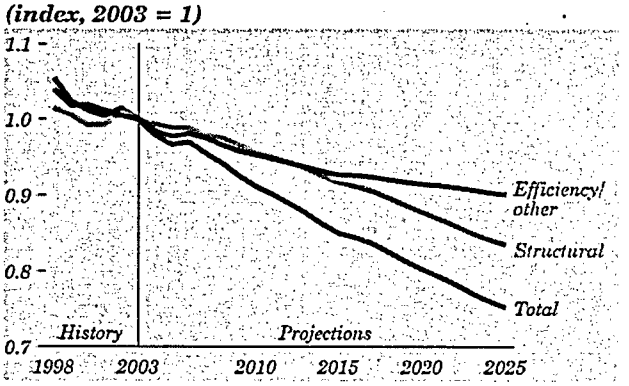
Two-thirds of the energy consumed in the industrial sector is used to provide heat and power for manufacturing. Of the remainder approximately 14 percent is used for nonmanufacturing heat and power, and 19 percent goes to nonfuel uses, such as raw materials and asphalt (Figure 54).

Nonfuel use of energy (feedstocks and asphalt) in the industrial sector is projected to grow at a slightly slower rate than heat and power consumption (0.8 percent and 1.1 percent per year, respectively). The feedstock portion of nonfuel use is projected to grow by 0.9 percent per year, marginally slower than the growth of output from the bulk chemical industry (1.0 percent per year through 2025), because of changes in the product mix. In 2025, feedstock consumption is projected to total 4.3 quadrillion Btu. Asphalt use is projected to grow by 0.7 percent per year, to 1.4 quadrillion Btu in 2025. The construction industry is the principal consumer of asphalt for paving and roofing. Asphalt use grows more slowly than construction output (1.8 percent per year through 2025), because not all construction activities require asphalt.

Petroleum refining, bulk chemicals, and pulp and paper are the largest consumers of energy for heat and power in the industrial sector. These three energy-intensive industries used 11.7 quadrillion Btu of energy (including feedstocks) in 2003. Energy use for petroleum refining grows more rapidly than any other energy-intensive industry, by 1.7 percent per year through 2025. Growth in energy use for the bulk chemicals and pulp and paper industries is projected at 0.8 percent and 0.9 percent, respectively.

Output From U.S. Industries Grows Faster Than Energy Use

Figure 55. Components of improvement in industrial delivered energy intensity, 1998-2025 (index, 2003 = 1)

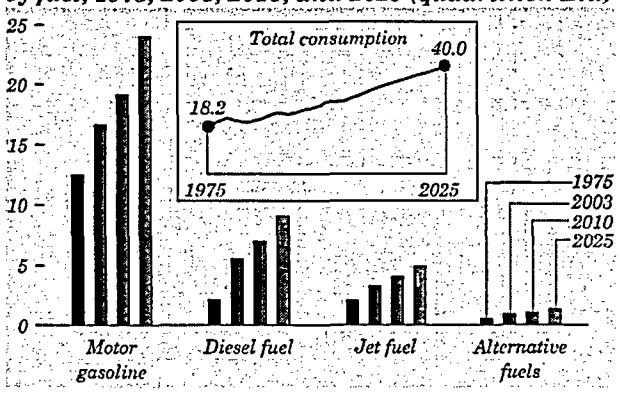


Changes in industrial energy intensity (consumption per unit of output) can be separated into two components. One reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of industrial value of shipments. The use of more energy-efficient technologies, combined with relatively slow growth in the energy-intensive industries, has dampened growth in industrial energy consumption over the past decade. Thus, despite a 25-percent increase in industrial output, energy use in the sector grew by only 2 percent between 1990 and 2003.

Industrial value of shipments is projected to grow by 2.3 percent between 2003 and 2025. The share of total industrial shipments attributed to the energy-intensive industries is projected to fall from 21 percent in 2003 to 17 percent in 2025. Consequently, even if no specific industry experienced a decline in intensity, aggregate industrial energy intensity would decline. Figure 55 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*131*]. From 2003 to 2025, industrial delivered energy intensity is projected to drop by 25 percent. The changing composition of industrial output is expected to result in a drop in energy intensity of approximately 16 percent by 2025. Thus, almost two-thirds of the expected change in delivered energy intensity for the sector is attributable to structural shifts and the remainder to changes in energy intensity associated with projected increases in equipment and production efficiencies.

Alternative Fuels Make Up 2.2 Percent of Light-Duty Vehicle Fuel Use in 2025

Figure 56. Transportation energy consumption by fuel, 1975, 2003, 2010, and 2025 (quadrillion Btu)



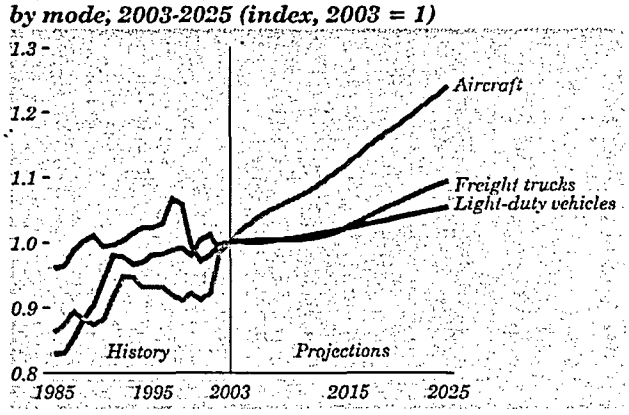
Energy demand for transportation is projected to grow from 27.1 quadrillion Btu in 2003 to 40.0 quadrillion Btu in 2025 (Figure 56). In the reference case, motor gasoline use increases by 1.7 percent per year from 2003 to 2025, when it makes up 60 percent of transportation energy use. Alternative fuels are projected to displace 207,000 barrels of oil equivalent per day [*132*] in 2010 and 280,500 barrels per day (2.2 percent of light-duty vehicle fuel consumption) in 2025, in response to current environmental and energy legislation intended to reduce oil use. Gasoline's share of demand is expected to be sustained, however, by low prices relative to the rate of inflation and slower fuel efficiency gains for conventional cars, vans, pickup trucks, and sport utility vehicles than were achieved in the 1980s.

Assumed industrial output growth of 2.3 percent per year from 2003 to 2025 leads to an increase in freight truck use, with a corresponding 2.3-percent annual increase in diesel fuel use. Economic growth and low projected jet fuel prices yield an annual increase in air travel of 2.2 percent from 2003 to 2025 and a 1.9-percent average annual increase in jet fuel use.

Demand for light-duty vehicle fuels is projected to increase from 16.2 quadrillion Btu in 2003 to 24.5 quadrillion Btu in 2025. Light-duty diesel vehicles are assumed to meet the emission standards for diesel fuel, and diesel fuel grows from 1.5 percent of total light-duty vehicle fuel consumption in 2003 to 4.4 percent in 2025. Alternative fuels, consisting mostly of ethanol used in gasoline blending (71 percent in 2025) and liquefied petroleum gas (14 percent) grow from 1.7 percent of the 2003 total to 2.2 percent in 2025.

Average Horsepower for New Cars Is Projected To Grow by 26 Percent

Figure 57. Transportation stock fuel efficiency by mode, 2003-2025 (index, 2003 = 1)



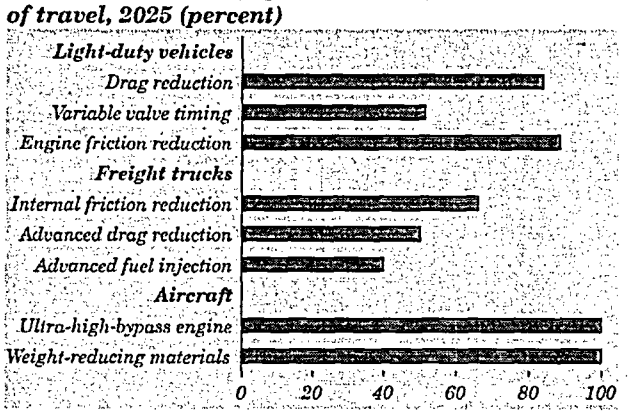
Fuel efficiency is projected to improve more rapidly from 2003 to 2025 than it did during the 1990s. Fuel economy for the light-duty vehicle stock is projected to improve by 5 percent, and for the stock of freight trucks from 6.0 miles per gallon in 2003 to 6.6 in 2025 (Figure 57). No changes are assumed in currently promulgated fuel efficiency standards for cars and light trucks. Low fuel prices and higher personal incomes are expected to increase the demand for larger, more powerful vehicles, with average horsepower for new cars projected to be 26 percent above the 2003 average in 2025 (Table 26). Advanced technologies and materials are expected to provide increased performance and size while improving new vehicle fuel economy [*133*]. Advanced technologies are projected to boost the average fuel economy of new light-duty vehicles by about 1.8 miles per gallon, to 26.9 miles per gallon in 2025 from 25.1 miles per gallon in 2003.

Table 26. New car and light truck horsepower ratings and market shares, 1990-2025

	Cars			Light trucks		
Year	Small	Medium	Large	Small	Medium	Large
1990						
Horsepower	119	145	176	132	157	185
Sales share	0.60	0.28	0.12	0.48	0.21	0.30
2003						
Horsepower	149	184	224	181	193	241
Sales share	0.54	0.33	0.13	0.31	0.34	0.35
2010						
Horsepower	171	211	247	208	212	276
Sales share	0.50	0.35	0.15	0.30	0.34	0.35
2025						
Horsepower	188	233	265	223	219	284
Sales share	0.50	0.35	0.15	0.30	0.34	0.35

New Technologies Promise Better Vehicle Fuel Efficiency

Figure 58. Technology penetration by mode of travel, 2025 (percent)



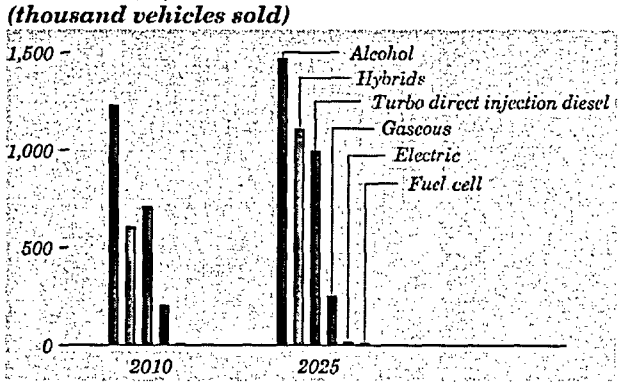
Fuel economy for new light-duty vehicles is projected to be 26.9 miles per gallon in 2025 (automobiles 31.0 miles per gallon, light-duty trucks 24.6 miles per gallon) as a result of advances in fuel-saving technologies (Figure 58). Three of the most promising would provide more than 4 percent higher fuel economy each: advanced drag reduction, variable valve timing and lift, and technologies that reduce internal engine friction. Advanced drag reduction reduces air resistance over the vehicle; variable valve timing optimizes the timing of air intake into the cylinder with the spark ignition during combustion; and reduced engine friction increases engine efficiency through more efficient designs, bearings, and coatings that reduce resistance between moving parts.

Due to concerns about economic payback, the trucking industry is more sensitive to the marginal cost of fuel-efficient technologies; however, several technologies can increase fuel economy significantly, including components to reduce internal friction (2-percent improvement), advanced drag reduction (2 percent), and advanced fuel injection systems (5 percent). These technologies are expected to penetrate the heavy-duty truck market by 2025. Advanced technology penetration is projected to increase the average fuel efficiency of new freight trucks from 6.1 miles per gallon in 2003 to 6.8 miles per gallon in 2025.

New aircraft fuel efficiencies are projected to increase by 19 percent from 2003 levels by 2025. Ultra-high-bypass engine technology can potentially increase fuel efficiency by 10 percent, and increased use of weight-reducing materials may contribute up to a 15-percent improvement.

Advanced Technologies Are Projected To Reach 19 Percent of Sales by 2025

Figure 59. Sales of advanced technology light-duty vehicles by fuel type, 2010 and 2025 (thousand vehicles sold)

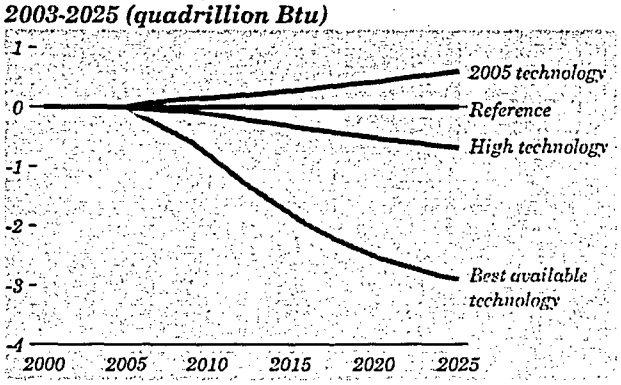


Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, are projected to reach 3.8 million vehicle sales per year and make up 19.1 percent of total light-duty vehicle sales in 2025. Alcohol flexible-fueled vehicles are projected to continue to lead advanced technology vehicle sales, at 1.5 million vehicles in 2025 (Figure 59). Hybrid electric vehicles (specifically designed to use electric motors and batteries in combination with a combustion engine to drive the vehicle), introduced into the U.S. market by two manufacturers in 2000, are anticipated to sell well: 607,000 units are projected to be sold in 2010, increasing to 1.1 million units in 2025. Sales of turbo direct injection diesel vehicles are projected to increase to 710,000 units in 2010 and 1 million units in 2025.

About 80 percent of advanced technology sales are as a result of Federal and State mandates for fuel economy standards, emissions programs, or other energy regulations. Currently, manufacturers selling alcohol flexible-fueled vehicles receive fuel economy credits that count toward compliance with corporate average fuel economy regulations. In the *AEO2005* forecast, the majority of projected gasoline hybrid, fuel cell, and electric vehicle sales result from compliance with low-emission vehicle programs in California, New York, Maine, Vermont, and Massachusetts. *AEO2005* does not include the impacts of California Assembly Bill 1493, which effectively sets carbon emission standards for light-duty vehicles, because of uncertainty about the State's ability to enforce the standards.

Advanced Technologies Could Reduce Residential Energy Use

Figure 60. Variation from reference case delivered residential energy use in three alternative cases, 2003-2025 (quadrillion Btu)



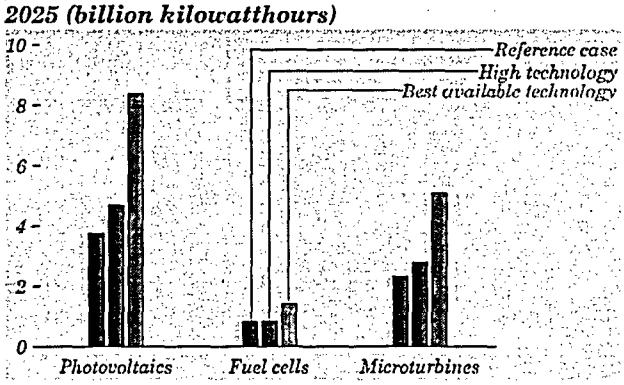
The reference case includes the effects of several policies aimed at increasing residential end-use efficiency, including minimum efficiency standards and voluntary energy savings programs to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2005 technology case, assuming no increase in efficiency of equipment or building shells beyond that available in 2005, 4 percent more energy would be required in 2025 than projected in the reference case (Figure 60).

In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, projected residential delivered energy use in 2025 is 20 percent lower than in the reference case and 24 percent lower than in the 2005 technology case. Through 2025, projected additional investment of $442 billion relative to that in the reference case would be necessary to save a projected $139 billion in energy costs in the best available technology case [*134*].

The high technology case does not constrain consumer choices. Instead, the most energy-efficient technologies are assumed to be available earlier, with lower costs and higher efficiencies. The consumer discount rates used to determine the purchased efficiency of all residential appliances in the high technology case do not vary from those used in the reference case; that is, consumers value efficiency equally across the two cases. Delivered energy consumption in 2025 in the high technology case is projected to be 5 percent lower than in the reference case; however, the savings are not as great as those projected in the best available technology case.

Advanced Technologies Could Slow Electricity Sales Growth for Buildings

Figure 61. Buildings sector electricity generation from advanced technologies in alternative cases, 2025 (billion kilowatthours)



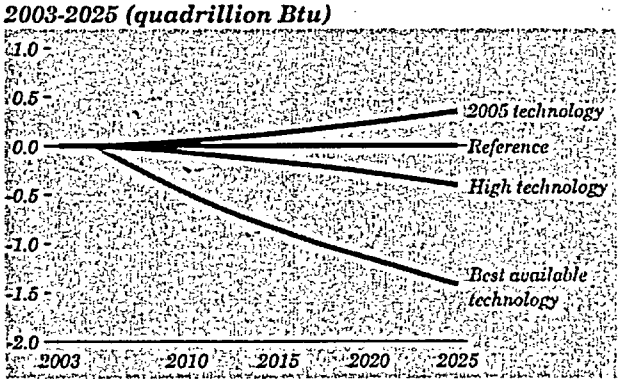
Alternative technology cases for the residential and commercial sectors include varied assumptions for the availability and market penetration of advanced distributed generation technologies (solar photovoltaic systems, fuel cells, and microturbines). Some of the heat produced by fossil-fuel-fired generating systems may be used to satisfy heating requirements, increasing system efficiency and the attractiveness of the advanced technologies, particularly in alternative cases with more optimistic technology assumptions.

In the high technology case, buildings are projected to generate 1.4 billion kilowatthours (8 percent) more electricity in 2025 than in the reference case (Figure 61), most of which offsets residential and commercial electricity purchases. In the best available technology case, projected electricity generation in buildings in 2025 is 8.0 billion kilowatthours (47 percent) higher than in the reference case. In the 2005 technology case, assuming no further technological progress or cost reductions after 2005, electricity generation in buildings in 2025 is 6.5 billion kilowatthours (38 percent) lower than projected in the reference case.

The additional natural gas use projected for fuel cells and microturbines to provide heat and power in commercial buildings in the high technology case offsets reductions from improved building shells and end-use equipment. Although the best technology case projects even higher adoption of these technologies, the additional end-use savings projected when the most efficient technologies are chosen, regardless of cost, outweigh the additional natural gas consumption needed to fuel distributed generation systems.

Advanced Technologies Could Reduce Commercial Energy Use

Figure 62. Variation from reference case delivered commercial energy use in three alternative cases, 2003-2025 (quadrillion Btu)

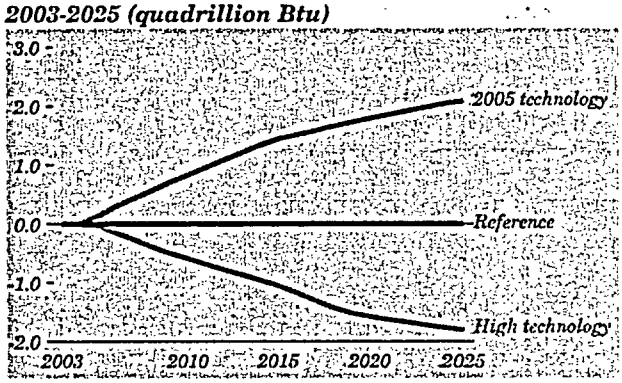


The *AEO2005* reference case incorporates efficiency improvements for commercial equipment and building shells, which help to limit the projected rate of increase in commercial energy intensity (delivered energy use per square foot of floorspace) to 0.2 percent per year over the forecast. The 2005 technology case assumes that future equipment and building shells will be no more efficient than those available in 2005. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment than in the reference case and more rapid improvement in building shells. The best available technology case assumes that only the most efficient technologies will be chosen, regardless of cost, and that building shells will improve at a faster rate than assumed in the high technology case.

In the 2005 technology case, projected energy use in 2025 is 3 percent higher than the 12.5 quadrillion Btu in the reference case (Figure 62), as a result of an 0.3-percent average annual increase in commercial delivered energy intensity. The high technology case projects a 3-percent energy savings in 2025 relative to the reference case, with little change in energy intensity from 2003 to 2025. In the best available technology case, commercial delivered energy intensity is projected to improve by 0.4 percent per year, and projected energy use in 2025 is 11 percent lower than in the reference case. More optimistic assumptions result in additional projected energy savings from both renewable and conventional fuel-using technologies. In 2025, commercial solar photovoltaic systems are projected to generate more than twice as much electricity in the best technology case as in the reference case.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 63. Variation from reference case delivered industrial energy use in two alternative cases, 2003-2025 (quadrillion Btu)



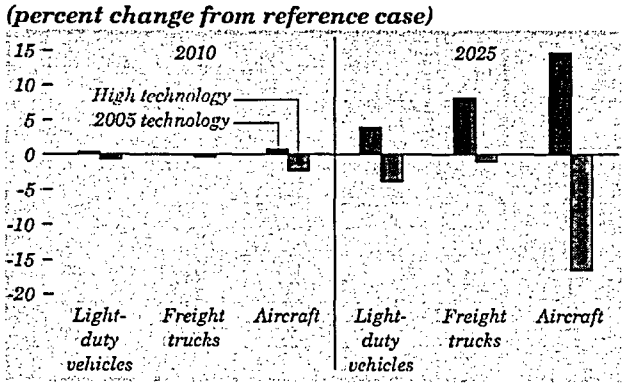
Efficiency gains in both energy-intensive and non-energy-intensive industries are projected to reduce overall energy intensity in the industrial sector. Expected output growth in metal-based durables (3.4 percent per year), driven primarily by investment and export-related demand, is a key factor. In the reference case, this non-energy-intensive group of industries grows more than twice as fast as the energy-intensive sectors (1.5 percent per year).

In the high technology case, 1.8 quadrillion Btu less energy is used in 2025 than for the same level of output in the reference case. Industrial energy intensity improves by 1.6 percent per year through 2025 in this case, compared with 1.3-percent annual improvement in the reference case (Figure 63). Industrial cogeneration capacity is projected to increase more rapidly in the high technology case (2.7 percent per year) than in the reference case (2.2 percent per year).

In the 2005 technology case, industry is projected to use 2.1 quadrillion Btu more energy in 2025 than in the reference case. Energy efficiency remains at the level achieved by new equipment in 2005, but average efficiency still improves as old equipment is retired. Aggregate industrial energy intensity is projected to decline by 1.0 percent per year because of reduced efficiency gains. The change in industrial structure is the same in the 2005 technology and high technology cases as in the reference case, because the same macroeconomic assumptions are used for the three cases, but the relative effects of the change varies, accounting for 63 percent of the change in intensity in the reference case, 52 percent in the high technology case, and 83 percent in the 2005 technology case.

Vehicle Technology Advances Reduce Transportation Energy Demand

Figure 64. Changes in projected transportation fuel use in two alternative cases, 2010 and 2025 (percent change from reference case)

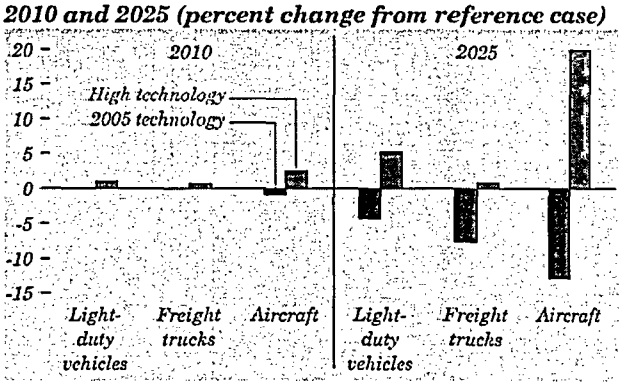


In the *AEO2005* reference case, delivered energy use in the transportation sector is projected to increase from 27.1 quadrillion Btu in 2003 to 40.0 quadrillion Btu in 2025. In the high technology case, the projection for 2025 is 1.9 quadrillion Btu (4.7 percent) lower, with about 54 percent (1.0 quadrillion Btu) of the difference attributed to efficiency improvements in light-duty vehicles (Figure 64) as a result of increased penetration of advanced technologies, including variable valve lift, electrically driven power steering pumps, and advanced electronic transmission controls. Similarly, projected fuel use by heavy freight trucks in 2025 is 0.1 quadrillion Btu lower in the high technology case than in the reference case, and advanced aircraft technologies are projected to reduce fuel use for air travel by 0.7 quadrillion Btu in 2025.

In the 2005 technology case, with new technology efficiencies fixed at 2005 levels, efficiency improvements can result only from stock turnover. As a result, total delivered energy demand for transportation in 2025 is 2.3 quadrillion Btu (5.8 percent) higher in 2025 in the 2005 technology case than projected in the reference case. Projected fuel use for air travel in 2025 is 0.7 quadrillion Btu (15 percent) higher in the 2005 technology case than in the reference case, and freight trucks are projected to use 0.6 quadrillion Btu (8.3 percent) more fuel in 2025 [*135*].

Technology Assumptions Include Improvements in Vehicle Efficiency

Figure 65. Changes in projected transportation fuel efficiency in two alternative cases, 2010 and 2025 (percent change from reference case)



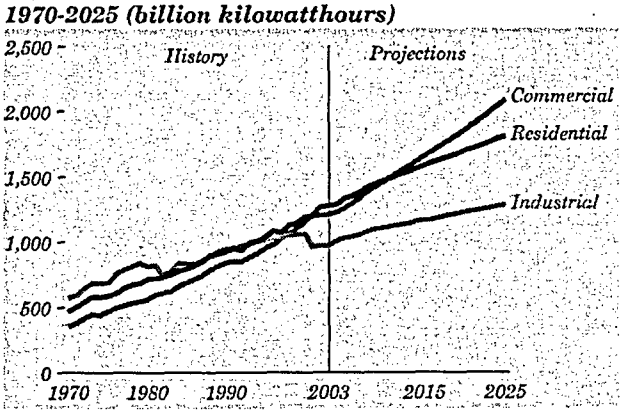
The high technology case assumes lower costs and higher efficiencies for new transportation technologies. Advances in conventional technologies are projected to increase the average fuel economy of new light-duty vehicles in 2025 from 26.9 miles per gallon in the reference case to 28.8 miles per gallon in the high technology case. The average efficiency of the light-duty vehicle stock is 20.3 miles per gallon in 2010 and 22.1 miles per gallon in 2025 in the high technology case, compared with 20.1 miles per gallon in 2010 and 21.0 miles per gallon in 2025 in the reference case (Figure 65).

For freight trucks, average stock efficiency in the high technology case is 0.6 percent higher in 2010 and 1.0 percent higher in 2025 than the reference case projection of 6.6 miles per gallon. Advanced aircraft technologies increase projected aircraft efficiency by 3 percent in 2010 and 20 percent in 2025 relative to the reference case projections.

In the 2005 technology case, the average fuel economy of new light-duty vehicles is projected to be 24.9 miles per gallon in 2025, and the projected average for the entire light-duty vehicle stock is 20.1 miles per gallon in 2025. For freight trucks, the projected average stock efficiency in 2025 is 6.1 miles per gallon. Aircraft efficiency in 2025 is projected to average 59.7 seat-miles per gallon in the 2005 technology case, compared with 68.5 seat-miles per gallon in the reference case.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 66. Annual electricity sales by sector, 1970-2025 (billion kilowatthours)



Total electricity sales are projected to increase at an average annual rate of 1.9 percent in the *AEO2005* reference case, from 3,481 billion kilowatthours in 2003 to 5,220 billion kilowatthours in 2025 (Figure 66). From 2003 to 2025, annual growth in electricity sales is projected to average 1.6 percent in the residential sector, 2.5 percent in the commercial sector, and 1.3 percent in the industrial sector.

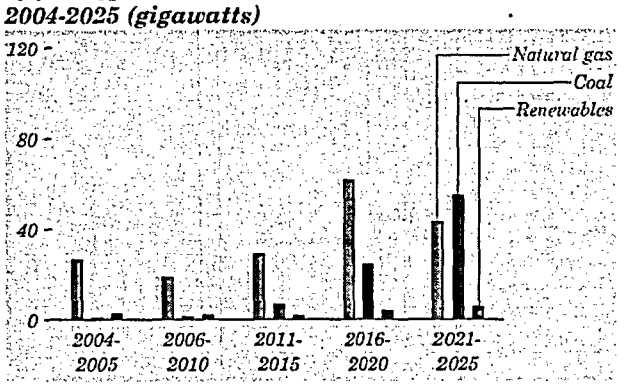
The average size of homes is projected to be larger in 2025 than in 2003 in terms of both square footage and ceiling height, with corresponding increases in electricity use for heating, cooling, and lighting. In addition, expected population shifts to warmer climates increase the amount of electricity used for air conditioning, although the projected increases are mitigated in part by the implementation of a more stringent efficiency standard for air conditioners and heat pumps in 2006.

Projected efficiency gains for electric equipment in the commercial sector are offset by the continuing penetration of new telecommunications technologies and medical imaging equipment, increased use of office equipment, and more rapid additions of floorspace.

Although electricity use is projected to increase with the growth of industrial output, increases in electricity sales to the industrial sector are expected to be offset by a 2.7-percent average annual increase in onsite generation.

Early Capacity Additions Use Natural Gas, Coal Plants Are Added Later

Figure 67. Electricity generation capacity additions by fuel type, including combined heat and power, 2004-2025 (gigawatts)



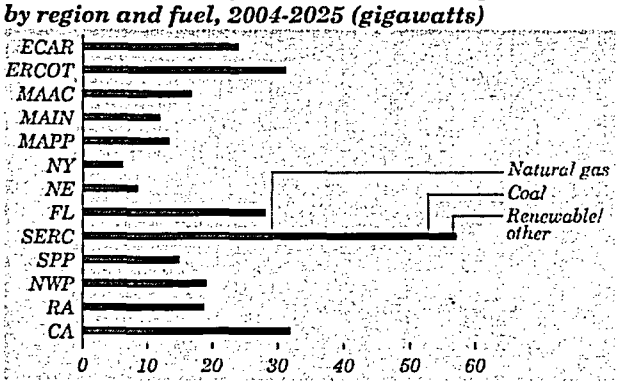
With growing electricity demand and the retirement of 43 gigawatts of inefficient, older generating capacity, 281 gigawatts of new capacity (including end-use combined heat and power) will be needed by 2025. Most retirements are expected to be older oil- and natural-gas-fired steam capacity, along with smaller amounts of older oil- and natural-gas-fired combustion turbines and coal-fired capacity, which are not competitive with newer natural gas combustion turbine or combined-cycle capacity.

More than 60 percent of new capacity additions are projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technologies (Figure 67). More than 80 percent of the capacity additions will be needed after 2010, when the current excess of generation capacity has been reduced. As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become increasingly competitive, accounting for nearly one-third of the capacity expansion expected in the reference case. Most of the new coal capacity is expected to use advanced pulverized coal technology and to begin operation after 2015. About 16 gigawatts of capacity using advanced clean coal technology, with higher capital costs but relatively low fuel costs, is also expected to be added.

About 5 percent of the projected capacity expansion consists of renewable generating units. Another 7 gigawatts of distributed generation, mostly gas-fired microturbines, is also expected to be added by 2025. Oil-fired steam plants with higher fuel costs and lower efficiencies are expected to be used only for new industrial combined heat and power capacity.

Capacity Additions Are Expected To Be Required in All Regions

Figure 68. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2004-2025 (gigawatts)



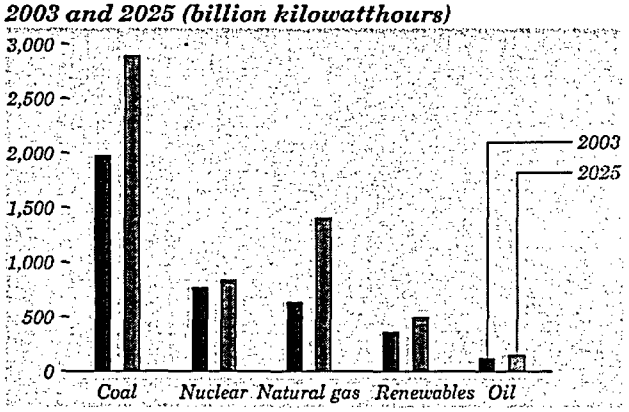
Most areas of the United States currently have excess generation capacity, but all the electricity demand regions (see Appendix G for definitions) are expected to need additional, currently unplanned, capacity by 2025 (Figure 68). Some new plants already are under construction, nearly all of which are expected to be completed by 2010.

The need for new capacity is expected to be greatest in the Southeast and the West. Although comparatively small geographically, the Southeast accounts for about 30 percent of projected total demand in 2025 and a comparable share of expected capacity additions. The size of the region's electricity market is the principal reason for the amount of new capacity required, and the projected growth in its demand for electricity growth is also slightly higher than the national average. The West, which geographically is the largest electricity demand region, currently represents less than 20 percent of the Nation's total electricity demand, but it accounts for 25 percent of projected capacity additions. Relatively strong growth in demand is projected for the West.

Capacity additions in the Southeast and the West are expected to be considerably more diverse than in the other areas of the country, where most additions are projected to be natural-gas-fired capacity. Almost all additions of coal-fired and renewable capacity are expected to be in these two areas. Of the 87 gigawatts of new coal-fired capacity, the Southeast and West account for 36 percent and 40 percent, respectively. Nationally, new renewable generating capacity is expected to total 15 gigawatts, with 28 percent and 34 percent located in the Southeast and West.

Natural Gas and Coal Meet Most Needs for New Electricity Supply

Figure 69. Electricity generation by fuel, 2003 and 2025 (billion kilowatthours)



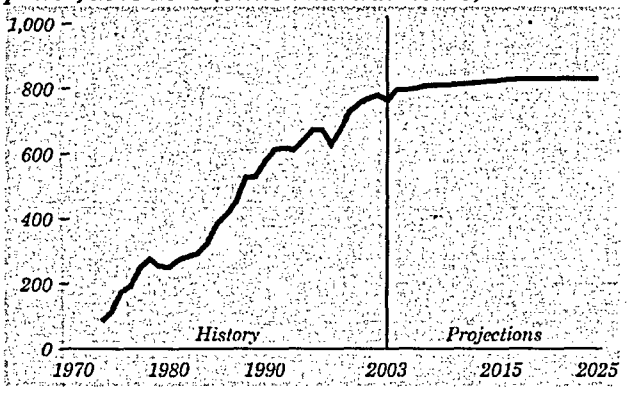
Coal-fired power plants are expected to continue supplying most of the Nation's electricity through 2025 (Figure 69). In 2003, coal-fired plants (including utilities, independent power producers, and end-use combined heat and power) accounted for 51 percent (1,970 billion kilowatthours) of all electricity generation. Their output is projected to increase to 2,890 billion kilowatthours in 2025, while their share of total generation declines to 50 percent as a result of a rapid increase in natural-gas-fired generation.

In compliance with environmental regulations, about one-third of existing coal-fired capacity has been fitted with scrubbers to reduce sulfur dioxide emissions, and another 27 gigawatts of currently existing capacity is expected to have scrubbers in 2025. A total of 87 gigawatts of new coal-fired capacity is projected to be added in the reference case, mostly after 2010, as natural gas prices continue to rise. Nuclear generation, currently the second-largest source of electricity, is expected to increase modestly, as a result of additional improvements in plant performance and expansions of existing capacity, before leveling off after 2017.

Natural gas is expected to have the largest increase in its share of total electricity generation, from 17 percent in 2003 to 20 percent in 2010 and 24 percent in 2025, and by 2010 it is expected to overtake nuclear power as the second-largest source of electricity production. Generation from renewable sources, including hydropower, is projected to increase by 36 percent from 2003 to 2025, but its share of total electricity supply is projected to decline from 9 percent in 2003 to 8 percent in 2025.

Nuclear Power Plant Capacity Factors Are Expected To Increase Modestly

Figure 70. Electricity generation from nuclear power, 1973-2025 (billion kilowatthours)



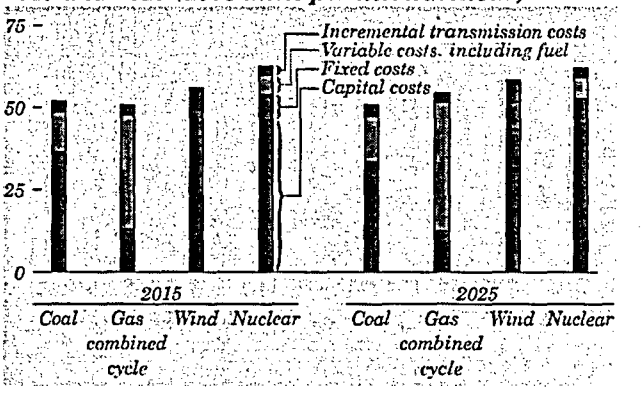
The United States currently has 104 commercial nuclear reactors licensed to operate, providing about 20 percent of the total 3,690 billion kilowatthours of electricity generated in 2003 (Figure 70). The performance of U.S. nuclear units has improved recently; the national average capacity factor rose to 90 percent in 2002 before dropping slightly to 88 percent in 2003. It is assumed that performance improvements will continue even as the plants age, leading to a weighted average capacity factor of 92 percent after 2010.

In the reference case, no nuclear units are projected to be retired from 2003 to 2025. Nuclear capacity grows slightly, due to assumed increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 8 applications for power uprates in 2003, and another 12 were approved or pending in 2004. The reference case assumes that all the uprates will be carried out, as well as others expected by the NRC over the next 15 years, leading to an increase of 3.5 gigawatts in total nuclear capacity by 2025. No new nuclear units are expected to become operable between 2003 and 2025.

Nuclear units would be retired if their operation were no longer economical relative to the cost of building replacement capacity. By 2025, the majority of nuclear units will be beyond their original license expiration dates. As of December 2004, license renewals for 30 nuclear units had been approved by the NRC, and 16 other applications were being reviewed. As many as 28 additional applicants have announced intentions to pursue license renewals over the next 3 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 71. Levelized electricity costs for new plants, 2015 and 2025 (2003 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 71) [*136*]. The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the risks of siting new units.

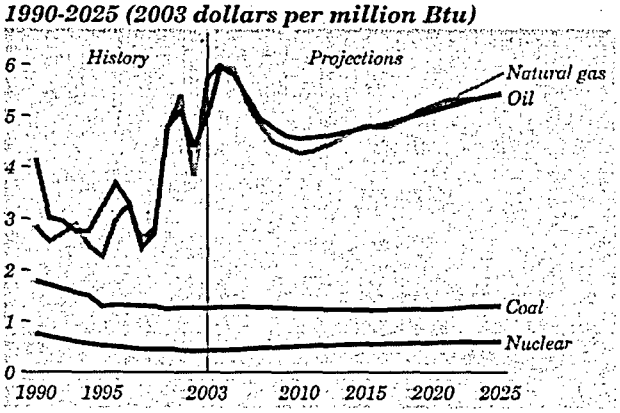
Capital costs are expected to be reduced over time (Table 27), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates for advanced combined cycle and coal gasification units declining to 6,333 and 7,200 Btu per kilowatthour, respectively, by 2010.

Table 27. Costs of producing electricity from new plants, 2015 and 2025

	2015		2025	
Costs	*Advanced coal*	*Advanced combined cycle*	*Advanced coal*	*Advanced combined cycle*
	2003 mills per kilowatthour			
Capital	31.68	11.63	28.87	11.08
Fixed	4.59	1.36	4.59	1.36
Variable	12.28	34.88	13.98	39.06
Incremental transmission	3.24	2.80	3.41	2.86
Total	**51.79**	**50.67**	**50.85**	**54.36**

Coal and Nuclear Fuel Costs Are Expected To Be Stable

Figure 72. Fuel prices to electricity generators, 1990-2025 (2003 dollars per million Btu)

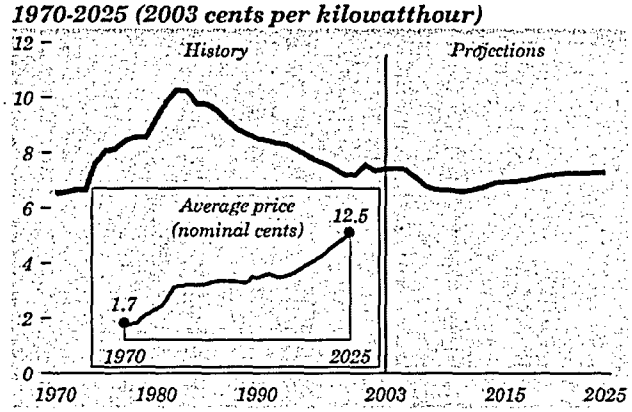


Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units. For a new coal-fired plant built today, fuel costs would represent about one-half of total operating costs, whereas the share for a new natural-gas-fired plant would be almost 90 percent. For nuclear units, fuel costs typically are a much smaller portion of total production costs, and nonfuel operations and maintenance costs make up a much larger share.

The impact of higher natural gas prices in the projections is offset by increased generation from coal-fired and nuclear power plants and by higher generation efficiencies as new capacity is installed. Although natural gas prices have been volatile in recent years, delivered prices to electricity generators are projected to peak at $6 per million Btu in 2004, then drop by almost 30 percent by 2010 before climbing steadily to almost $5.50 per million Btu in 2025 (Figure 72). Nuclear fuel costs, currently around $0.40 per million Btu (roughly 4 mills per kilowatthour), are projected to rise to about $0.60 per million Btu in 2025. Delivered petroleum prices to electricity generators follow a price path similar to that for natural gas prices, with a sharp drop through 2010 followed by a steady rise through 2025. Despite increasing fuel costs, the natural gas share of total generation is projected to increase from 16 percent in 2003 to 24 percent in 2025 because of the higher efficiency of gas-fired capacity.

Average Electricity Prices Decline From 2001 Highs, Then Gradually Rise

Figure 73. Average U.S. retail electricity prices, 1970-2025 (2003 cents per kilowatthour)

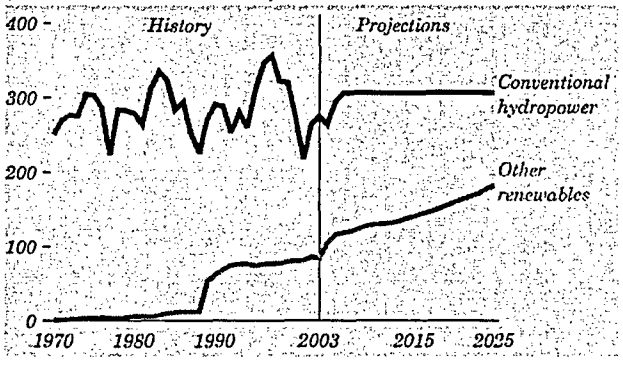


Average U.S. electricity prices, in real 2003 dollars, are expected to decline by 11 percent, from 7.4 cents per kilowatthour in 2003 to 6.6 cents in 2011 (Figure 73), then rise to 7.3 cents per kilowatthour in 2025. Prices follow the trend of the generation cost component of price, which makes up 65 percent of the total price of electricity and changes mainly in response to changes in natural gas prices. The distribution component, 28 percent of the total electricity price, is expected to decline from 2003 to 2025 at an average annual rate of 0.7 percent, as the cost of distribution infrastructure is spread over a growing amount of total electricity trade. Transmission prices are expected to increase at an average annual rate of 1.0 percent because of the additional investment needed to meet projected growth in electricity demand. Electricity prices for individual customer classes are projected to follow the average price trend, declining through 2011 and then increasing for the remainder of the forecast. Residential and commercial prices in 2025 are projected to be slightly lower than 2003 prices, and industrial prices are expected to be slightly higher than in 2003.

Competition in retail and wholesale generation markets can strongly influence electricity prices. In 2004, 17 States and the District of Columbia had competitive retail electricity markets in operation. Montana, Nevada, New Mexico, and Oklahoma have delayed opening competitive retail markets; Arkansas has repealed its restructuring legislation; and California's competitive retail market is suspended. Many States have cited a lack of operational wholesale markets and inadequate generation and transmission capacity as reasons for delaying retail competition.

Increases in Nonhydropower Renewable Generation Are Expected

Figure 74. Grid-connected electricity generation from renewable energy sources, 1970-2025 (billion kilowatthours)

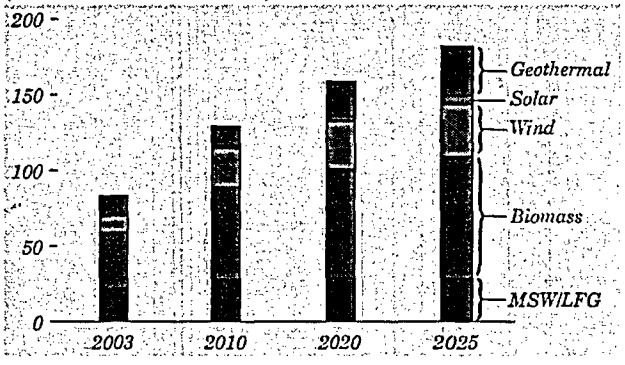


Despite strong growth in renewable electricity generation as a result of technology improvements and expected higher fossil fuel costs, grid-connected generators using renewable fuels (including combined heat and power and other end-use generators) are projected to remain minor contributors to U.S. electricity supply. From 359 billion kilowatthours in 2003 (9.3 percent of total generation) renewable generation increases to only 489 billion kilowatthours (8.5 percent) in 2025 (Figure 74).

Conventional hydropower remains the major source of renewable generation in the *AEO2005* reference case. After 4 years of below-normal precipitation, hydroelectric generation is expected to recover in 2005; however, with little new capacity expected, conventional hydropower generation is projected to increase from 275 billion kilowatthours in 2003 (7.1 percent of total generation) to just 307 billion kilowatthours (5.3 percent of the total) in 2025. Other renewables account for 5.3 percent of projected additions to capacity from 2003 to 2025 and 6.4 percent of the projected increase in generation. Generation from nonhydropower renewables increases from 84 billion kilowatthours in 2003 (2.2 percent of generation) to 182 billion kilowatthours in 2025 (3.2 percent). Biomass, including combined heat and power systems and biomass co-firing in coal-fired plants, is the largest source of other renewable generation in the forecast. Electricity from biomass combustion increases from 37 billion kilowatthours in 2003 (1.0 percent) to 81 billion kilowatthours in 2025 (1.4 percent), with 49 percent of the increase coming from dedicated power plants and the rest primarily from combined heat and power.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 75. Nonhydroelectric renewable electricity generation by energy source, 2003-2025 (billion kilowatthours)

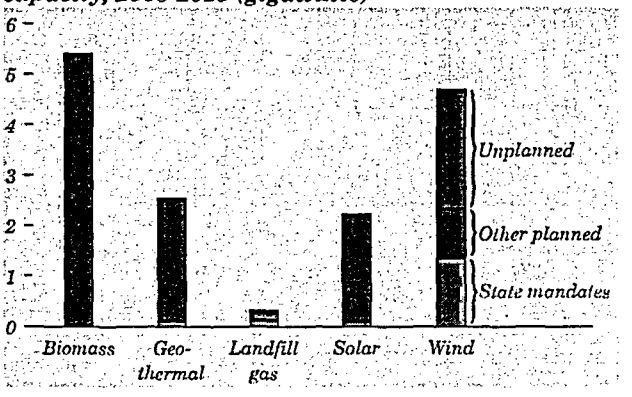


AEO2005 projects significant increases in electricity generation from both geothermal and wind power (Figure 75). In the West, geothermal output increases from 13 billion kilowatthours in 2003 to 33 billion kilowatthours in 2025. Wind-powered generating capacity increases from 6.6 gigawatts in 2003 to 11.3 gigawatts in 2025, and generation from wind capacity increases from less than 11 billion kilowatthours in 2003 to 35 billion in 2025. The mid-term prospects for wind power are uncertain, depending on response to the recent extension of the Federal production tax credit through 2005 and the likelihood of further extensions, as well as responses to State programs, technology improvements, transmission availability, and public interest.

Generation from municipal solid waste and landfill gas (MSW/LFG) is projected to increase by 7 billion kilowatthours, to 29 billion kilowatthours in 2025, but little new municipal solid waste capacity is expected. Solar technologies generally are projected to remain too costly to be competitive in supplying power to the grid. Central-station photovoltaic capacity increases in the forecast from about 40 megawatts in 2003 to 400 megawatts in 2025, and solar thermal capacity increases from about 400 megawatts to more than 500 megawatts. In contrast, individual grid-connected photovoltaic installations grow rapidly, from about 60 megawatts in 2003 to nearly 1,800 megawatts in 2025. Grid-connected photovoltaics and solar thermal, which together provided about 0.7 billion kilowatthours of electricity in 2003, are projected to supply nearly 6 billion kilowatthours in 2025 [*137*].

State Programs Will Continue To Support Renewable Energy Use

Figure 76. Additions of renewable generating capacity, 2003-2025 (gigawatts)



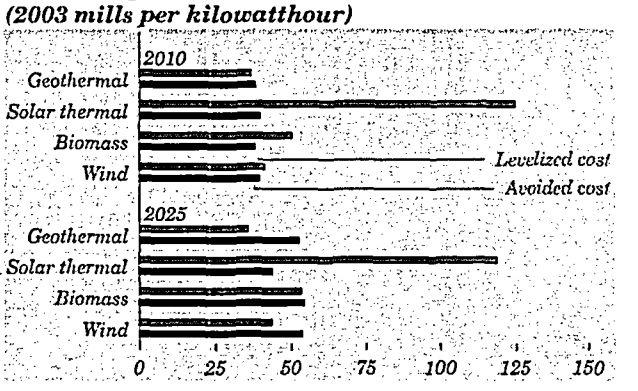
In the *AEO2005* reference case, 14.9 gigawatts of new nonhydroelectric renewable energy capacity is projected to enter service from 2003 through 2025, including 10.6 gigawatts in the electric power sector, 2.6 gigawatts of combined heat and power, and 1.7 gigawatts of end-use applications. In the electric power sector, 1.6 gigawatts is projected as a result of State requirements and goals (wind 1.3 gigawatts, geothermal and landfill gas each 0.1 gigawatt, plus smaller amounts of biomass, waste, and solar capacity) and the rest from commercial projects (Figure 76).

Most new renewables capacity projected in the near term results from specific projects and State programs. After 2010, the projected growth in renewable energy capacity is based on its ability to become competitive in electricity markets. The Federal production tax credit for wind plants was not extended until late in 2004, and so only 213 megawatts of new wind capacity is expected to be completed in 2004. In 2005, however, more than 1 gigawatt of new capacity is expected to enter service before the credit expires on December 31.

Because States with renewable energy requirements have not added capacity as rapidly as projected in earlier forecasts, projections for new capacity resulting from State renewable portfolio standards, mandates, and nonmandatory goals are reduced in *AEO2005*, but they are still significant, including 903 megawatts expected in Texas, 146 megawatts each in California and Minnesota, 141 megawatts in Nevada, 80 megawatts in New Mexico, and 65 megawatts in Pennsylvania.

Renewables Are Expected To Become More Competitive Over Time

Figure 77. Levelized and avoided costs for new renewable plants in the Northwest, 2010 and 2025 (2003 mills per kilowatthour)

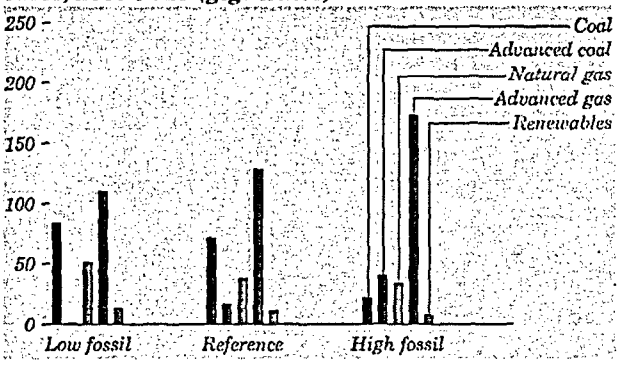


The competitiveness of both conventional and renewable generation resources is based on the most cost-effective mix of capacity that satisfies the demand for electricity across all hours and seasons. Baseload technologies tend to have low operating costs and set the marginal cost of power only during the hours of least demand. Dispatchable geothermal and biomass resources compete directly with new coal and nuclear plants, which to a large extent determine the avoided cost [*138*] for baseload energy (Figure 77). In some regions and years, new geothermal or biomass plants may be competitive with new coal-fired plants, but their development is limited by the availability of geothermal resources or competitive biomass fuels.

Intermittent technologies—specifically, wind and solar—can be used only when resources are available. Because of their relatively low operating costs and limited resource availability, the avoided costs of these technologies are determined largely by the operating costs of the most expensive units operating when their resources are available. Solar generators tend to operate during peak load periods, when gas-fired combustion turbines and combined-cycle units with higher fuel costs tend to determine avoided cost. The levelized cost of solar thermal generation is projected to be significantly higher than its avoided cost through 2025. The availability of wind resources varies among regions, but wind plants generally tend to displace intermediate load generation. Thus, the avoided costs of wind power will be determined largely by the low-to-modest operating costs of combined-cycle and coal-fired plants. In some regions and years, the levelized costs for wind power are projected to be below its avoided costs.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 78. Cumulative new generating capacity by technology type in three fossil fuel technology cases, 2003-2025 (gigawatts)

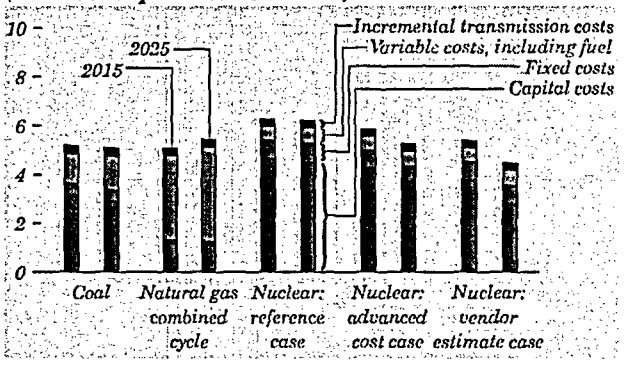


The *AEO2005* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Values for technology characteristics are determined in consultation with industry and government specialists, but uncertainty surrounds the assumptions for new technologies. In the high fossil fuel case, capital costs, heat rates, and operating costs for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, and advanced combustion turbine) reflect a 10-percent reduction from reference case levels in 2025. The low fossil fuel case assumes no change in capital costs and heat rates for advanced technologies from their 2005 levels.

Natural gas technologies make up the largest share of new capacity additions in all cases, but the mix of current and advanced technologies varies (Figure 78). In the high fossil fuel case, advanced technologies are used for 84 percent (173 gigawatts) of projected gas-fired capacity additions, compared with 69 percent (110 gigawatts) in the low fossil fuel case. The coal share of total capacity additions varies from 22 percent to 33 percent in the cases. In the low fossil fuel case, only a negligible amount of advanced coal-fired generating capacity is added. In the high fossil fuel case, advanced coal technologies are more competitive, making up 65 percent of all coal-fired capacity additions. The projections for average fossil fuel efficiency in the electric power sector in 2025 are 37 percent in the reference case, 38 percent in the high fossil fuel case, and 36 percent in the low fossil fuel case, based on different assumptions about the penetration of advanced technologies in the cases.

Sensitivity Cases Look at Possible Reductions in Nuclear Power Costs

Figure 79. Levelized electricity costs for new plants by fuel type in two nuclear cost cases, 2015 and 2025 (2003 cents per kilowatthour)

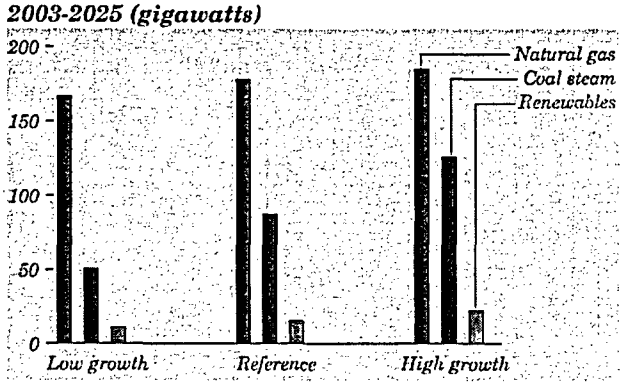


The *AEO2005* reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. Two alternative nuclear cost cases analyze the sensitivity of the projections to lower costs for new nuclear power plants. The advanced nuclear cost case assumes capital and operating costs 20 percent below the reference case in 2025, reflecting a 28-percent reduction in overnight capital costs from 2005 to 2025. (Earlier analysis showed that a 10-percent reduction in capital and operating costs would be insufficient to stimulate new nuclear construction.) The vendor estimate case assumes reductions relative to the reference case of 18 percent initially and 38 percent in 2025. These costs are consistent with estimates from British Nuclear Fuels Limited for the manufacture of its advanced pressurized-water reactor (AP1000). Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the two alternative nuclear cost cases are competitive with the generating costs projected for new coal- and natural-gas-fired units toward the end of the projection period (Figure 79). In the advanced nuclear case 7 gigawatts of new nuclear capacity is added by 2025, and in the vendor estimate case 25 gigawatts is added by 2025. The additional nuclear capacity displaces primarily projected new coal-fired capacity. The projections in Figure 79 are average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary across regions.

Rapid Economic Growth Would Boost New Coal and Renewable Capacity

Figure 80. Cumulative new generating capacity by technology type in three economic growth cases, 2003-2025 (gigawatts)



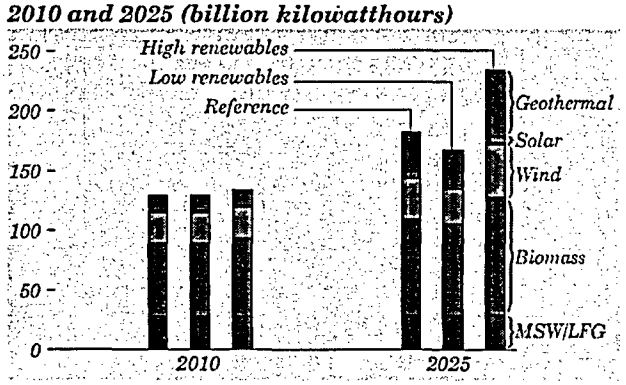
The projected annual average growth rate for GDP from 2003 to 2025 ranges from 3.6 percent in the high economic growth case to 2.5 percent in the low economic growth case. The difference leads to a 4-percent change in projected electricity demand in 2010 and a 12-percent change in 2025, with a corresponding difference of 105 gigawatts in the amount of new capacity projected to be built from 2003 to 2025 in the high and low economic growth cases, including combined heat and power in the end-use sectors.

Most (74 percent) of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new coal-fired plants. The stronger demand growth assumed in the high growth case is also projected to stimulate additions of renewable plants and new natural-gas-fired capacity (Figure 80). In the low economic growth case, total capacity additions are reduced by 53 gigawatts, and 70 percent of that projected reduction is in coal-fired capacity additions.

Average electricity prices in 2025 are 5 percent higher in the high economic growth case than in the reference case, due to higher natural gas prices and the costs of building additional generating capacity. Electricity prices in 2025 in the low economic growth case are projected to be 4 percent lower than in the reference case. In the high economic growth case, a 5-percent increase in consumption of fossil fuels results in a 6-percent increase in carbon dioxide emissions from electricity generators in 2025.

Lower Cost Assumptions Increase Biomass and Geothermal Capacity

Figure 81. Nonhydroelectric renewable electricity generation by energy source in three cases, 2010 and 2025 (billion kilowatthours)

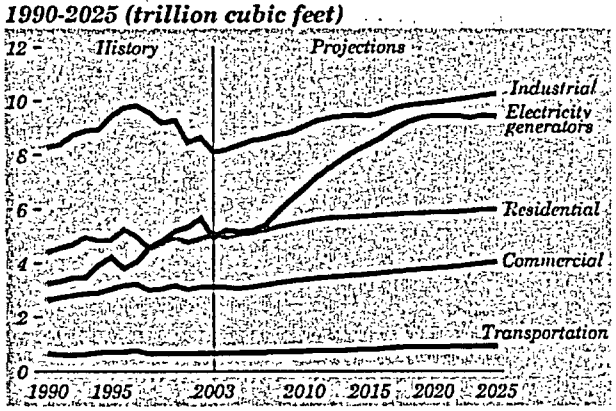


The impacts of key assumptions about the availability and cost of nonhydroelectric renewable energy resources for electricity generation are shown in two alternative technology cases. In the low renewables case, the cost and performance of generators using renewable resources are assumed to remain unchanged throughout the forecast. The high renewables case assumes cost reductions of 10 percent in 2025 on a site-specific basis for hydroelectric, geothermal, biomass, wind, and solar generating capacity (however, no new additions of conventional hydropower are projected in any of the cases, given the lack of suitable new sites for development).

In the low renewables case, construction of new renewable capacity is less than projected in the reference case (Figure 81). In the high renewables case, more additions of biomass, geothermal, and wind capacity are projected through 2025 than in the reference case, with most of the incremental capacity added between 2010 and 2025. In 2025, projected total electricity generation from nonhydropower renewables is 52 billion kilowatthours higher in the high renewables case than in the reference case, with most of the increment coming from geothermal (22.8 billion kilowatthours), biomass (18.0 billion kilowatthours), and wind energy (10.1 billion kilowatthours). Still, nonhydropower renewables are projected to remain relatively small contributors to total generation in the high renewables case, accounting for 134 billion kilowatthours (2.9 percent of the total) in 2010 and 235 billion kilowatthours (4.1 percent) in 2025.

Projected Increases in Natural Gas Use Are Led by Electricity Generators

Figure 82. Natural gas consumption by sector, 1990-2025 (trillion cubic feet)

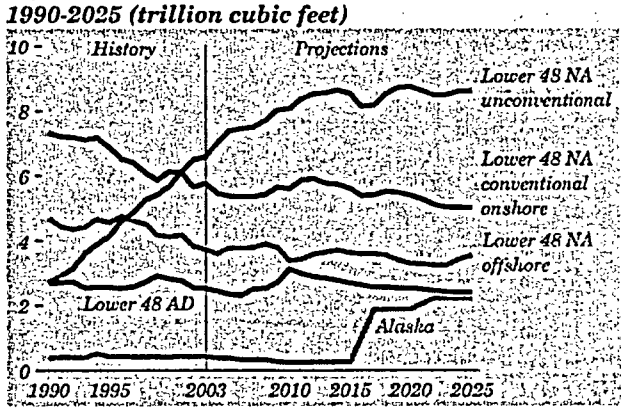


In the *AEO2005* reference case, total natural gas consumption increases from 22.0 trillion cubic feet in 2003 to 30.7 trillion cubic feet in 2025. In the electric power sector, natural gas consumption increases from 5.0 trillion cubic feet in 2003 to 9.4 trillion cubic feet in 2025 (Figure 82), accounting for 31 percent of total demand for natural gas in 2025 as compared with 23 percent in 2003. The increase in natural gas consumption for electricity generation results from both the construction of new gas-fired generating plants and higher capacity utilization at existing plants. Most new electricity generation capacity is expected to be fueled by natural gas, because natural-gas-fired generators are projected to have advantages over coal-fired generators that include lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions. Toward the end of the forecast, however, when natural gas prices rise substantially, coal-fired power plants are expected to be competitive for new capacity additions.

Industrial consumption of natural gas, including lease and plant fuel, is projected to increase from 8.1 trillion cubic feet in 2003 to 10.3 trillion cubic feet in 2025. Although increases are projected for most industrial sectors, decreases are expected in the iron, steel, and aluminum industries. The industrial sectors with the largest projected increases in natural gas consumption growth from 2003 through 2025 include metal-based durables, petroleum refining, bulk chemicals, and food. Natural gas use is also projected to increase in the residential sector by 0.7 percent per year and in the commercial sector 1.2 percent per year on average from 2003 to 2025.

Unconventional Production Becomes the Largest Source of U.S. Gas Supply

Figure 83. Natural gas production by source, 1990-2025 (trillion cubic feet)



As a result of technological improvements and rising natural gas prices, natural gas production from relatively abundant unconventional sources (tight sands, shale, and coalbed methane) is projected to increase more rapidly than conventional production. Lower 48 unconventional gas production grows from 6.6 trillion cubic feet in 2003 to 8.6 trillion cubic feet in 2025 (Figure 83) and from 35 percent of total lower 48 production in 2003 to 44 percent in 2025.

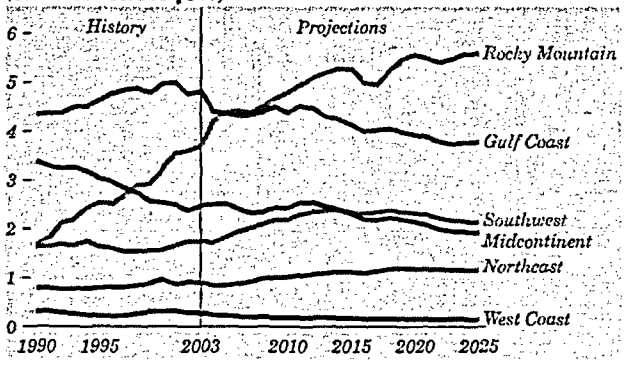
Production of lower 48 nonassociated (NA) conventional natural gas declines from 9.5 trillion cubic feet in 2003 to 8.6 trillion cubic feet in 2025, as resource depletion causes exploration and development costs to increase. Offshore NA natural gas production is projected to rise slowly to a peak of 3.9 trillion cubic feet in 2008, then decline to 3.6 trillion cubic feet in 2025.

Production of associated-dissolved (AD) natural gas from lower 48 crude oil reserves is projected to increase from 2.5 trillion cubic feet in 2003 to 3.1 trillion cubic feet in 2010 due to a projected increase in offshore AD gas production [*139*]. After 2010, both onshore and offshore AD gas production are projected to decline, and total lower 48 AD gas production falls to 2.4 trillion cubic feet in 2025.

The North Slope Alaska natural gas pipeline is projected to begin transporting Alaskan gas to the lower 48 States in 2016. In 2025, total Alaskan gas production is projected to be 2.2 trillion cubic feet in the reference case, compared with 0.4 trillion cubic feet in 2003.

Growing Production Is Expected from the Rocky Mountain Region

Figure 84. Lower 48 onshore natural gas production by supply region, 1990-2025 (trillion cubic feet)



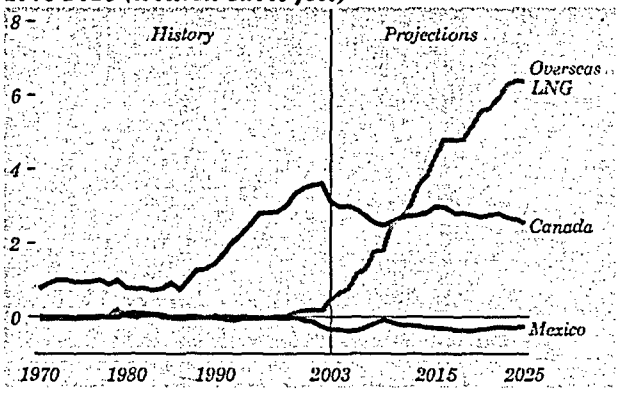
In the reference case, total natural gas supplies are projected to grow by 8.2 trillion cubic feet from 2003 to 2025. Domestic natural gas production is expected to account for 34 percent of the total growth in gas supply, and net imports are projected to account for the remaining 66 percent.

Over the forecast period, the largest increase in lower 48 onshore natural gas production is projected to come from the Rocky Mountain region, primarily from unconventional gas deposits [*140*]. Rocky Mountain natural gas production is projected to increase from 3.7 trillion cubic feet in 2003 to 5.6 trillion cubic feet in 2025 (Figure 84). In 2003, Rocky Mountain production was 27 percent of total lower 48 onshore production. The Rocky Mountain region's share of lower 48 onshore production is projected to increase to 38 percent in 2025. The only other increases in production are expected in the Northeast and Southwest regions. In the Northeast, production rises from 900 billion cubic feet in 2003 to 1.2 trillion cubic feet in 2019 and declines slightly thereafter. In the Southwest, production rises from 1.7 trillion cubic feet in 2003 to 2.4 trillion cubic feet in 2018 and declines to 2.1 trillion cubic feet in 2025.

Natural gas production in the onshore Gulf Coast and Midcontinent regions remains relatively constant through 2011, then declines to 3.8 and 1.9 trillion cubic feet, respectively, in 2025. West Coast production declines throughout the forecast. Regional declines in the projections reflect depletion of the natural gas resource base and increasing costs of gas exploration and development in those regions.

Net Imports of Natural Gas Grow in the Projections

Figure 85. Net U.S. imports of natural gas, 1970-2025 (trillion cubic feet)



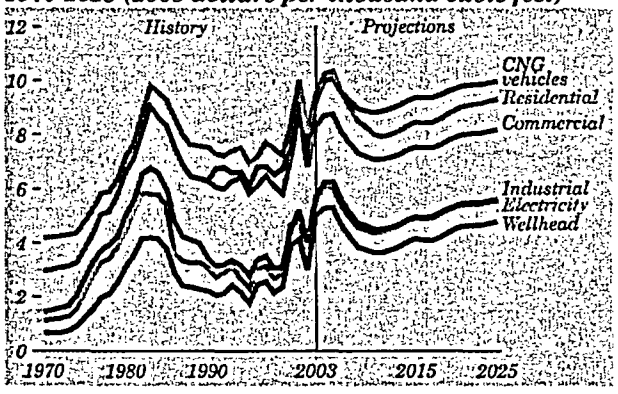
Net imports of natural gas make up the difference between U.S. production and consumption. Imports are expected to be priced competitively with domestic sources. Supplies of natural gas from overseas sources account for most of the projected increase in net imports in the reference case (Figure 85). New LNG terminals are projected to start coming into operation in 2006, and net LNG imports increase to 6.4 trillion cubic feet in 2025.

Net imports of natural gas from Canada are projected to decline from 3.0 trillion cubic feet in 2005 to 2.5 trillion cubic feet in 2009, rise again to 3.0 trillion cubic feet in 2015, and then decline to 2.5 trillion cubic feet in 2025. A steady decline of conventional production in the Western Sedimentary Basin is more than offset by increases in unconventional production in western Canada, conventional production in the MacKenzie Delta and Eastern Canada, and LNG imports. Although a MacKenzie Delta natural gas pipeline is expected to open in 2010, pipeline imports from Canada decline at the end of the forecast, because Canada's gas consumption increases more rapidly than its production.

Mexico has considerable natural gas resources, but the United States historically has been a net exporter of gas to Mexico, where industrial consumers along the border are closer to U.S. supplies than they are to domestic supplies. In the reference case, net U.S. exports to Mexico are projected to increase through 2006, when an LNG import terminal in Baja California, Mexico, begins exporting natural gas from western Mexico to the United States [*141*].

Delivered Prices Follow Projected Trends in Wellhead Prices

Figure 86. Natural gas prices by end-use sector, 1970-2025 (2003 dollars per thousand cubic feet)



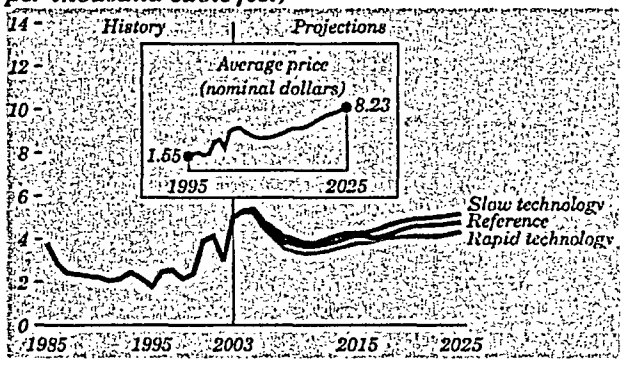
Trends in delivered natural gas prices largely reflect changes in wellhead prices. Wellhead natural gas prices are projected to decline in the early years of the *AEO2005* reference case forecast, as drilling levels increase, new production capacity comes on line, and LNG imports increase in response to current high prices. As a result, end-use delivered prices are projected to fall (Figure 86). After 2011, however, both wellhead and delivered natural gas prices are projected to increase in response to the higher exploration and development costs associated with smaller and deeper gas deposits in the remaining domestic gas resource base.

Transmission and distribution margins in the end-use sectors reflect both the volumes of gas delivered and the infrastructure arrangements of the sectors. The industrial and electricity generation sectors have the lowest end-use prices, because they receive most of their natural gas directly from interstate pipelines, avoiding local distribution charges. In addition, summer-peaking electric generators reduce transmission costs by using interruptible transportation rates during the summer, when there is spare pipeline capacity. As power generators take a larger share of the natural gas market, however, they are expected to rely more on higher cost firm transportation service.

On average, transmission and distribution margins are projected to remain relatively constant in the forecast, because the cost of new facilities largely offset the reduced depreciation expenses of existing facilities. If public opposition prevented the building of new infrastructure, delivered prices could be higher than projected in the reference case.

Technology Advances Could Moderate Future Natural Gas Prices

Figure 87. Lower 48 natural gas wellhead prices in three cases, 1985-2025 (2003 dollars per thousand cubic feet)



In the reference case, average lower 48 wellhead natural gas prices are projected to decline from the 2004 level to $3.64 per thousand cubic feet (2003 dollars) in 2010 and then increase to $4.79 per thousand cubic feet in 2025 (Figure 87). Technically recoverable natural gas resources (Table 28) are expected to be adequate to support projected production increases. As lower 48 conventional natural gas resources are depleted and wellhead prices rise, an increasing proportion of U.S. natural gas supply is projected to come from Alaska, unconventional production, and LNG imports.

In the slow oil and gas technology case, advances in exploration and production technologies are assumed to be 50 percent slower than those assumed in the reference case, which are based on historical rates. As a result, natural gas development costs are higher, wellhead prices are higher ($5.18 per thousand cubic feet in 2025), natural gas consumption is reduced, and LNG imports increase.

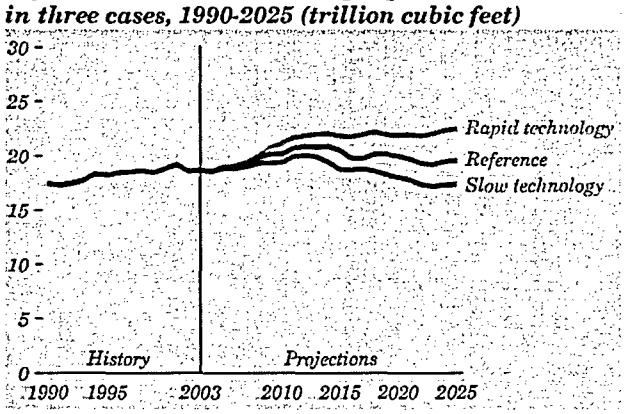
The rapid technology case assumes 50 percent faster technology progress than in the reference case, resulting in lower development costs, lower wellhead prices ($4.35 per thousand cubic feet in 2025), increased consumption of natural gas, and lower LNG imports than are projected in the reference case.

Table 28. Technically recoverable U.S. natural gas resources as of January 1, 2003 (trillion cubic feet)

Proved	Unproved	Total
186.9	1,150.5	1,337.5

Natural Gas Supply Projections Reflect Technological Progress Rates

Figure 88. Lower 48 natural gas production in three cases, 1990-2025 (trillion cubic feet)



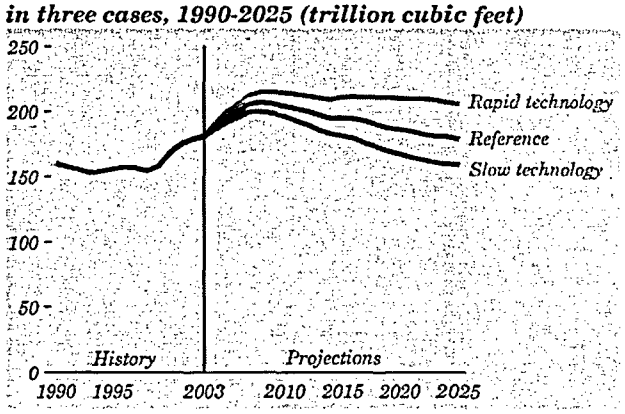
Because the impacts of technological progress are cumulative, the rapid and slow technology cases diverge increasingly from the reference case in the later years of the forecast (Figure 88). In the reference case, lower 48 natural gas production is projected to total 19.6 trillion cubic feet in 2025. The corresponding projections are 22.5 trillion cubic feet in the rapid oil and gas technology case and 17.4 trillion cubic feet in the slow technology case.

The cost-reducing effects of rapid technological progress primarily affect the economic recoverability of the unconventional resource base, because there are more opportunities for technological improvement in the exploration and recovery of unconventional gas than there are for conventional gas. In 2025, unconventional gas production is projected to be 11.0 trillion cubic feet in the rapid technology case and 7.1 trillion cubic feet in the slow technology case, compared with 8.6 trillion cubic feet in the reference case.

The rate of technological progress also affects the contributions of other natural gas supply sources. Because rapid progress is projected to increase the rate of production of lower 48 natural gas resources and reduce wellhead prices, both the Alaska gas pipeline and new LNG terminals are less viable economically in the rapid technology case than in the reference case, and their construction is delayed. In the slow technology case, more LNG terminal capacity is projected to be built, and the Alaska gas pipeline and some LNG terminals are projected to be built earlier. Projected LNG imports in 2025 total 5.7 trillion cubic feet in the rapid technology case and 6.8 trillion cubic feet in the slow technology case.

Rapid Technology Assumptions Raise Natural Gas Reserve Projections

Figure 89. Lower 48 natural gas reserves in three cases, 1990-2025 (trillion cubic feet)



Natural gas wellhead productive capacity directly reflects reserve levels. The *AEO2005* projections for lower 48 natural gas reserves are based on expected levels of natural gas exploration and development drilling resulting from projected cash flows and profitability. In the reference case, lower 48 reserves grow to 207 trillion cubic feet in 2008, then decline slowly to 178 trillion cubic feet in 2025 (Figure 89).

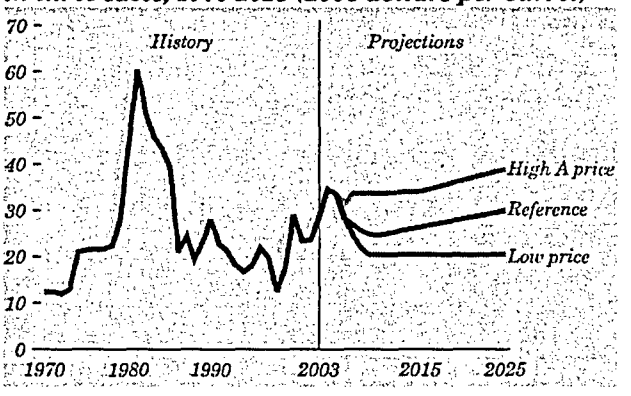
In the rapid technology case, the finding and success rates for gas well drilling are higher than in the reference case, and exploration and development costs are reduced, resulting in more drilling activity and reserve additions. In this case, lower 48 reserves are projected to peak at 215 trillion cubic feet in 2009, then decline to 205 trillion cubic feet in 2025.

In the slow technology case, finding and success rates are lower, exploration and development costs are higher, and drilling activity and reserve additions are lower than projected in the reference case. Lower 48 reserves are projected to peak at 200 trillion cubic feet in 2008, then decline to 159 trillion cubic feet in 2025.

In all three cases, the natural gas resource base is sufficient in the early years of the forecast to support the increases in drilling activity and reserve additions that are stimulated by higher projected prices. As a result, reserve additions early in the forecast generally exceed production. In later years, resource depletion reduces reserve additions per well, and rising costs of gas well development reduce drilling activity. As a result, production generally exceeds reserve additions, causing total reserves to decline toward the end of the forecast.

Oil Prices Are Expected To Decline from Recent Peaks, Then Rise

Figure 90. Lower 48 crude oil wellhead prices in three cases, 1970-2025 (2003 dollars per barrel)



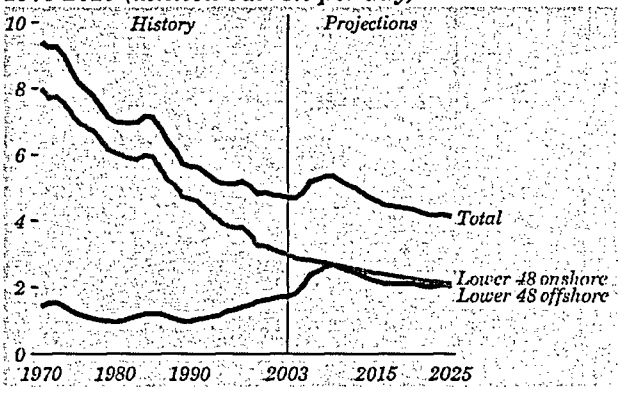
In the *AEO2005* reference case, the average lower 48 crude oil price (as distinct from the world oil price) is projected to decline from current levels to $24.50 per barrel (2003 dollars) in 2010, before increasing to $30.00 per barrel in 2025 (Figure 90). The U.S. price of oil, unlike natural gas, is set in the international marketplace. In the high A world oil price case, the lower 48 crude oil price is projected to be $33.65 per barrel in 2010 and $38.84 per barrel in 2025. In the low world oil price case, the lower 48 price declines to $20.44 per barrel in 2010, then remains relatively stable through 2025.

Between 2003 and 2010, crude oil prices are expected to decline as new deepwater oil fields are brought into production in the Gulf of Mexico and West Africa, new oil sands production is initiated in Canada, and OPEC and Russia expand production capacity. Near-term price expectations are highly uncertain, however, given the potential for political instability in many oil-exporting countries, which could significantly change the world's oil demand and supply picture.

Uncertainty about world oil prices in the longer term is reflected in the low and high A world oil price cases. Crude oil prices are determined largely by the balance between production and consumption and the mix of OPEC and non-OPEC production. In the reference case, oil production and consumption in 2025 are balanced at 120 million barrels per day, with OPEC accounting for 46 percent of total production. The low oil price case projects production of 128 million barrels per day in 2025, with the OPEC share at 51 percent. The high A case projects 114 million barrels per day, with the OPEC share at 37 percent.

Lower 48 Crude Oil Production Is Expected To Decline After 2009

Figure 91. Lower 48 crude oil production by source, 1970-2025 (million barrels per day)



In the reference case, total lower 48 crude oil production is projected to increase from 4.7 million barrels per day in 2003 to 5.4 million barrels per day in 2009, then decline to 4.1 million barrels per day in 2025 (Figure 91). In the low oil price case, lower 48 oil production peaks in 2009 at 5.3 million barrels per day, then declines to 3.9 million barrels per day in 2025. In the high A oil price case, lower 48 production peaks in 2009 at 5.4 million barrels per day and declines to 4.5 million barrels per day in 2025. The projected peaks in oil production are attributable to offshore production, particularly in the Gulf of Mexico, where deepwater oil production is projected to total 2.3 million barrels per day in 2009 (Table 29).

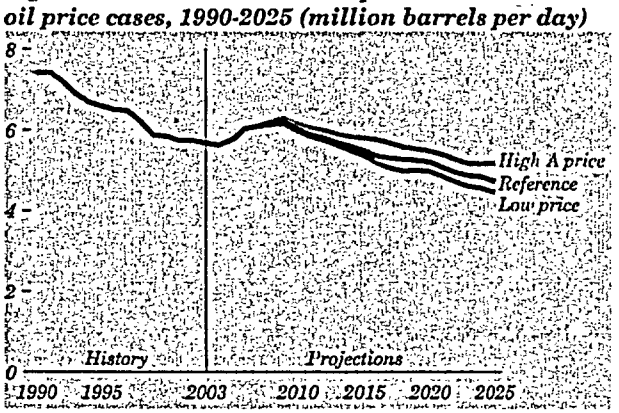
Offshore crude oil production is more sensitive than onshore production to oil prices, because a smaller portion of offshore oil resources has been depleted. In the reference case, total offshore production (including the Gulf of Mexico and offshore California) rises to 2.7 million barrels per day in 2009, then declines to 2.0 million barrels per day in 2025. In the low and high A price cases, the projections for lower 48 offshore production in 2025 are 1.9 million barrels per day and 2.3 million barrels per day, respectively. Onshore lower 48 oil production is projected to decline in all three cases, with 2025 values ranging from 2.0 million barrels per day in the low price case to 2.2 million barrels per day in the high A price case.

Table 29. Crude oil production from Gulf of Mexico offshore, 2003-2025 (million barrels per day)

	2003	2010	2015	2020	2025
Shallow	0.5	0.3	0.3	0.3	0.3
Deep	1.1	2.2	1.8	1.8	1.7
Total	1.6	2.5	2.1	2.1	2.0

U.S. Oil Production Is Marginally Sensitive to World Oil Prices

Figure 92. Total U.S. crude oil production in three oil price cases, 1990-2025 (million barrels per day)



The different paths projected for total U.S. crude oil production in the three world oil price cases reflect differences both in the numbers of new fields developed and in the volumes of oil recovered from existing fields. Total U.S. oil production is only marginally sensitive to crude oil price projections (Figure 92), both because future production is expected to come largely from developed fields, such as Prudhoe Bay, and because development of much of the remaining oil resource base (Table 30) would be uneconomical even with much higher oil prices. In the high A and low world oil price cases, total U.S. production in 2025 is projected at 5.2 and 4.5 million barrels per day, respectively.

The different price paths in the three cases primarily affect the development and production of lower 48 offshore resources (Table 31). Smaller deepwater fields that are not profitable when prices are low are expected to become profitable at higher price levels.

Table 30. Technically recoverable U.S. oil resources as of January 1, 2003 (billion barrels)

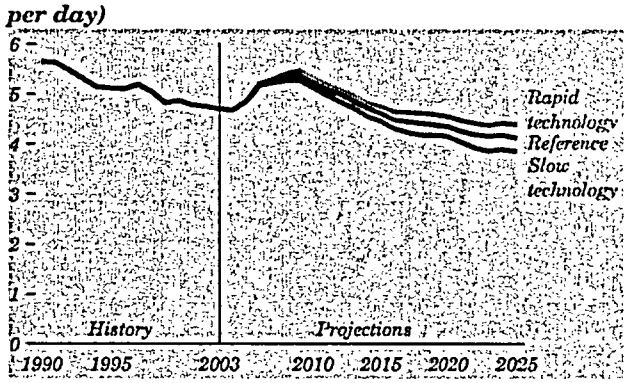
Proved	Unproved	Total
24.0	118.8	142.8

Table 31. Onshore and offshore lower 48 crude oil production in three cases, 2025 (million barrels per day)

	Onshore	Offshore	Total
Low oil price	2.03	1.88	3.91
Reference	2.09	2.03	4.12
High A oil price	2.16	2.30	4.47

More Rapid Technology Advances Could Raise Oil Production

Figure 93. Lower 48 crude oil production in three technology cases, 1990-2025 (million barrels per day)

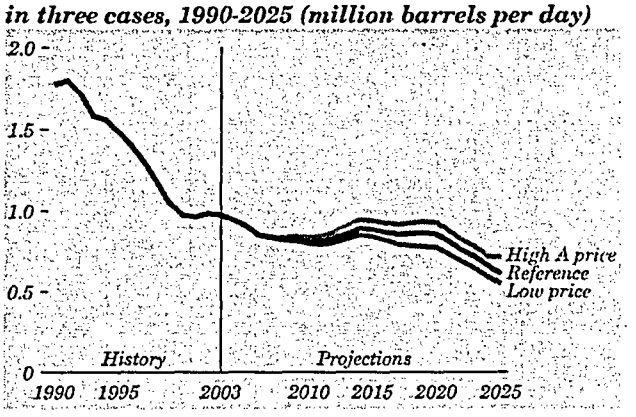


Lower 48 crude oil production is projected to reach 4.4 and 3.9 million barrels per day in 2025 in the rapid and slow technology cases, respectively, compared with 4.1 million barrels per day in the reference case (Figure 93). The technology cases assume the same world oil prices as in the reference case, but the rate of technological progress is assumed to be 50 percent higher (in the rapid technology case) or lower (in the slow technology case) than the historical rate. With domestic oil demand determined largely by oil prices and economic growth rates, consumption is not expected to change significantly in the technology cases. Thus, changes in production resulting from the different rates of technological progress lead to different projected levels of petroleum imports. In 2025, net petroleum imports are projected to range from 18.5 million barrels per day in the rapid technology case to 19.6 million barrels per day in the slow technology case, as compared with 19.1 million barrels per day in the reference case.

In the lower 48 States, offshore crude oil production is more sensitive than onshore production to changes in technology, because there are more opportunities for technological improvement in the less mature areas offshore, particularly in the deepwater Gulf of Mexico. Cumulative offshore production from 2004 through 2025 is projected to be 0.7 billion barrels (4.0 percent) higher in the rapid technology case and 0.8 billion barrels (4.7 percent) lower in the slow technology case than in the reference case. Cumulative onshore production is about 0.4 billion barrels (2.0 percent) higher in the rapid oil and gas technology case and 0.4 billion barrels (1.8 percent) lower in the slow technology case than in the reference case.

Crude Oil Production in Alaska Depends on Oil Prices

Figure 94. Alaskan crude oil production in three cases, 1990-2025 (million barrels per day)



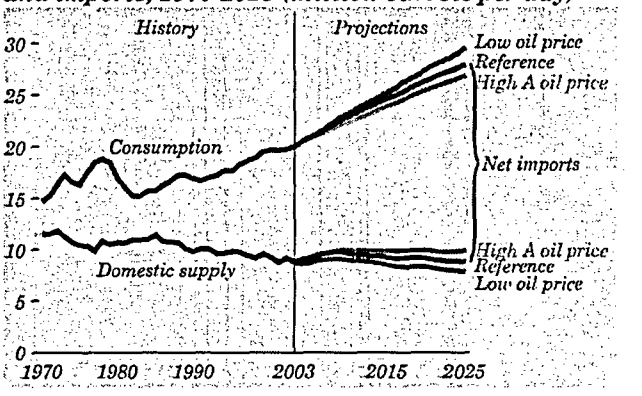
Alaskan crude oil production originates mainly from the North Slope, which includes the National Petroleum Reserve-Alaska (NPR-A) and the State lands surrounding Prudhoe Bay. Because oil and gas producers are prohibited from building permanent roads in NPR-A, exploration and production are expected to be about 30 percent more expensive than is typical for the North Slope of Alaska. Because drilling is currently prohibited in the Arctic National Wildlife Refuge (ANWR), *AEO2005* does not project any production from ANWR; however, an EIA analysis [*142*] projects that if drilling were allowed, production would start 10 years later and reach 900,000 barrels per day in 2025 if the area contains the mean level of resources (10.4 billion barrels) estimated by the U.S. Geological Survey.

In the reference case, crude oil production from Alaska is expected to decline to about 810,000 barrels per day in 2010 (Figure 94). After 2010, increased production from NPR-A raises Alaska's total production to about 890,000 barrels per day in 2014. Depletion of the oil resource base in the North Slope, NPR-A, and southern Alaska oil fields is expected to lead to a decline in the State's total production to about 610,000 barrels per day in 2025.

As in the lower 48 States, oil production in Alaska is marginally sensitive to projected changes in oil prices. Higher prices make more of the reservoir oil in-place profitable. In 2025, Alaska's production is projected to be about 100,000 barrels per day above the reference case level in the high A oil price case and 60,000 barrels per day below the reference case level in the low oil price case.

Imports Fill the Gap Between Domestic Supply and Demand

Figure 95. Petroleum supply, consumption, and imports, 1970-2025 (million barrels per day)



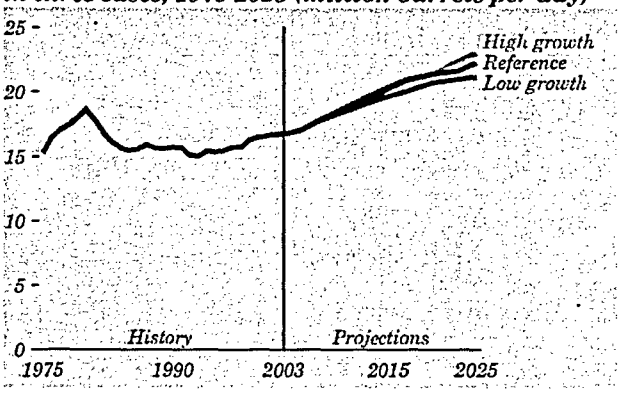
In 2003, net imports of crude oil and refined products accounted for 56 percent of domestic petroleum consumption. Dependence on petroleum imports is projected to reach 68 percent in 2025 in the reference case (Figure 95). The corresponding import shares of total consumption in 2025 are expected to be 63 percent in the high A oil price case and 72 percent in the low oil price case.

The portion of domestic petroleum demand that is supplied by imports depends on the world crude oil price. Because imported products are the most expensive source of petroleum supply, the first effect of assuming crude oil prices above those projected in the reference case is reduced consumption of imported petroleum products. Higher prices also stimulate the production of relatively high-cost domestic crude oil, resulting in lower projected levels of imported crude. Prices below those in the reference case have the opposite effect: U.S. consumption and product imports increase, production of domestic crude oil falls, and the portion of petroleum consumption met by imports rises.

Although crude oil is expected to continue as the major component of petroleum imports, refined products are projected to represent a growing share. More petroleum product imports would be needed as the projected growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products are projected to make up 21 percent of net petroleum imports in 2025 in the low oil price case and 12 percent in the high A oil price case, compared with 16 percent in the reference case, increasing from a 14-percent share in 2003.

Expansion at Existing Refineries Increases U.S. Refining Capacity

Figure 96. Domestic refining capacity in three cases, 1975-2025 (million barrels per day)



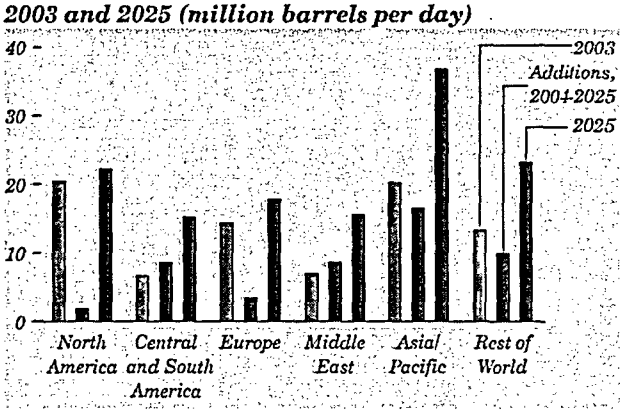
Falling demand for petroleum and deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1996, and 1.4 million barrels per day of distillation capacity was added between 1996 and 2003. Financial and legal considerations make it unlikely that new refineries will be built in the United States, but additions at existing refineries are expected to increase total U.S. refining capacity in all the *AEO2005* cases (Figure 96).

Distillation capacity is projected to grow from the 2003 year-end level of 16.8 million barrels per day to 22.3 million barrels per day in 2025 in the reference case, 21.4 million in the high A oil price case, and 22.5 million in the low price case, as compared with the 1981 peak of 18.6 million barrels per day. Almost all new capacity additions are projected to occur on the Gulf Coast. Existing refineries are expected to continue to be utilized intensively (92 to 95 percent of operable capacity) throughout the forecast. The 2003 utilization rate was 93 percent, well above the lows of 69 percent during the 1980s and 88 percent during the early 1990s but consistent with capacity utilization rates since the mid-1990s.

Distillation is only the first step in the refining process. Improved processing of the intermediate streams obtained from crude distillation is expected to reduce yields of residual fuel, which has a shrinking market, and improve yields of the higher value "light products," such as gasoline, distillate, jet fuel, and liquefied petroleum gas. Further process improvements will be required to reduce the sulfur content of gasoline and some types of distillate fuel.

Asia/Pacific Region Is Expected To Surpass U.S. Refining Capacity

Figure 97. Worldwide refining capacity by region, 2003 and 2025 (million barrels per day)



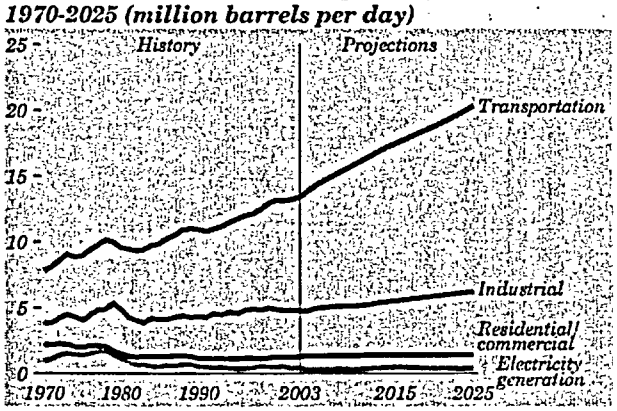
Worldwide crude oil distillation capacity was 82.0 million barrels per day at the end of 2003. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by about 60 percent—to more than 131 million barrels per day—by 2025. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 97).

The Asia/Pacific region has been the fastest growing refining center over the past decade. In the mid-1990s, it surpassed Western Europe as the world's second largest refining center (after North America) in terms of distillation capacity; and in 2003, capacity in the Asia/Pacific region capacity was only 220,000 barrels per day lower than that in North America. While not adding significantly to their distillation capacity, refiners in the United States and Europe have tended to improve product quality and enhance the usefulness of heavier oils through investment in downstream capacity.

Future investments in the refinery operations of developing countries must include configurations that are more advanced than those currently in operation. Their refineries will be called upon to meet increased worldwide demand for lighter products, to upgrade residual fuel, to supply transportation fuels with reduced lead, and to supply both distillate and residual fuels with lower sulfur levels. An additional burden on new refineries will be the need to supply lighter products from crude oils whose quality is expected to deteriorate over the forecast period.

Petroleum Use Increases Mainly in the Transportation Sector

Figure 98. Petroleum consumption by sector, 1970-2025 (million barrels per day)



The transportation sector accounted for two-thirds of U.S. petroleum use in 2003 (Figure 98). In the forecast, population growth and economic growth cause miles traveled to increase across all modes of transit. Although improvements in vehicle technology yield reductions in fuel use per mile traveled, the increases in mileage outweigh increases in efficiency, leading to increases in consumption of gasoline, diesel, and jet fuel.

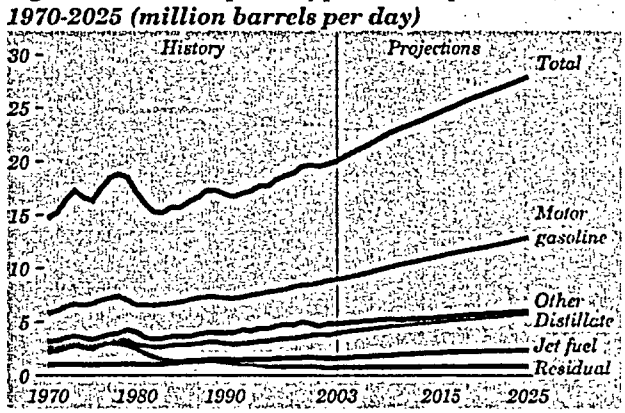
The industrial sector currently accounts for 24 percent of U.S. petroleum demand. In the reference case, industrial consumption is projected to be 1.2 million barrels per day higher in 2025 than it was in 2003, and industrial consumption of liquefied petroleum gas (LPG), largely as a chemical feedstock, increases by about 490,000 barrels per day.

In the residential sector, distillate use is displaced by LPG, natural gas, and electricity for home heating toward the end of the forecast, in systems that require less maintenance than oil furnaces. As a result, residential oil use drops by 88,000 barrels per day from 2003 to 2025. Commercial use of heating oil grows from 246,000 barrels per day in 2003 to 362,000 barrels per day in 2025. The delivered price of distillate to commercial customers is projected to be lower than the price of natural gas throughout the forecast.

Only 3 percent of U.S. electricity is currently generated from refined petroleum, but the electricity sector nearly matches residential petroleum use by the end of the forecast. Consumption of residual and distillate fuel in the electric power sector increase modestly.

Light Products Account for Most of the Increase in Demand for Petroleum

Figure 99. Consumption of petroleum products, 1970-2025 (million barrels per day)



U.S. petroleum consumption is projected to increase by 7.9 million barrels per day from 2003 to 2025 (Figure 99). About 92 percent of the projected growth in petroleum consumption consists of "light products" (including gasoline, diesel, heating oil, jet fuel, kerosene, LPG, and petrochemical feedstocks), which are more difficult and costly to produce than heavy products.

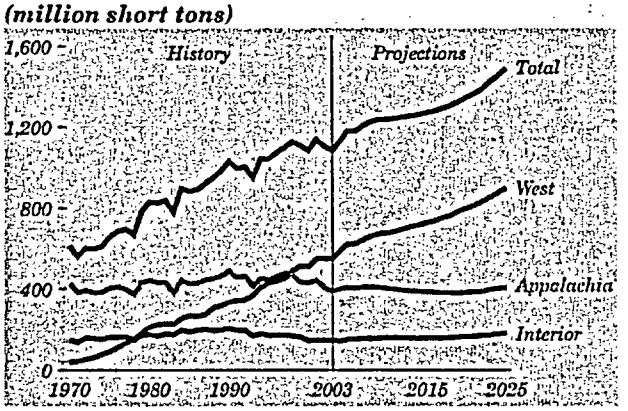
Gasoline continues to make up nearly one-half of all petroleum used in the United States, increasing from 8.9 million barrels per day in 2003 to 12.9 million in 2025, mostly for transportation. Consumption of distillate fuel is also projected to increase, by 1.9 million barrels per day, from 2003 to 2025. Gasoline is used only in spark-ignition engines; distillate is used in furnaces, boilers, diesel engines, and some turbines. Jet fuel consumption is projected to increase by 789,000 barrels per day from 2003 to 2025.

Consumption of "other" petroleum products is projected to increase from 4.8 million barrels per day in 2003 to 6.0 million barrels per day in 2025. LPG used for heating and chemical production is included in the "other" category, along with other chemical feedstocks, still gas used for refinery fuel, and asphalt.

Residual fuel use, constrained by air quality regulations, increases by only 110,000 barrels per day from 2003 to 2025, including an increase of 79,000 barrels per day in residual fuel use for baseload electricity generation. More intensive refinery processing to maximize light product yield and minimize heavy product yield is expected to limit the availability of residual fuel. LPG use also remains about constant.

Emissions Caps Lead to More Use of Low-Sulfur Coal From Western Mines

Figure 102. Coal production by region, 1970-2025 (million short tons)



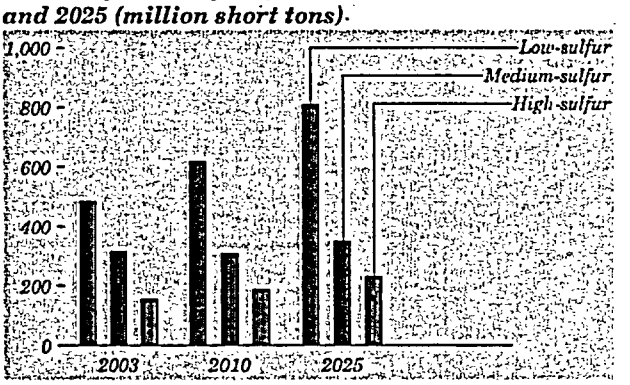
U.S. coal production has remained near 1,100 million tons annually since 1997. In the early years of the *AEO2005* forecast, a projected increase in coal use for electricity generation leads to an increase in production, to 1,238 million tons in 2010. After 2010, coal production increases with projected additions of new, unplanned coal-fired generating capacity, particularly from 2015 to 2025.

Little change is projected for Appalachian coal production (Figure 102). The region has been mined extensively, and increases in demand are likely to be met with coal from other areas. In the Interior region, production is projected to increase by 36 million tons from 2003 to 2025. Western coal production, which has grown steadily since 1970, is projected to continue to increase through 2025, especially in the Powder River Basin, where vast reserves are contained in thick seams accessible to surface mining. Easing of rail transportation bottlenecks will be key for coal producers in the West to take advantage of market opportunities presented by slower growth in Appalachian production, fuel switching at existing power plants, and demand from new power plants expected to be built in the West and Southeast regions.

The use of Western coals can reduce sulfur dioxide emissions by up to 85 percent relative to many types of higher sulfur eastern coals. As coal demand grows over the forecast, however, new coal-fired generating capacity is required to use the best available control technology (scrubbers or advanced coal technologies), which can reduce sulfur emissions by 90 percent or more, providing market opportunities for higher sulfur coal later in the forecast.

Low-Sulfur Coal Continues To Gain Share in the Generation Market

Figure 103. Distribution of domestic coal to the electricity sector by sulfur content, 2003, 2010, and 2025 (million short tons)



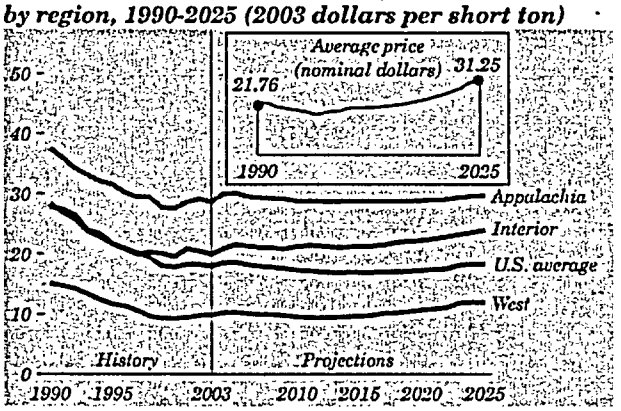
To reduce sulfur dioxide emissions as required under Phase 1 of CAAA90, many generators switched from higher sulfur coals to low-sulfur coal, leading to an excess of sulfur dioxide allowances. The excess allowances generated were banked or sold for use in Phase 2, which took effect on January 1, 2000. Low-sulfur coal will continue to be used in generator compliance strategies and is also expected to be attractive to many generators where it is the least expensive coal available.

Distribution of low-sulfur coal to the electricity sector is projected to increase on average by 3.1 percent per year between 2003 and 2011 (Figure 103) as most banked allowances are used. After 2017, low-sulfur coal maintains about a 58-percent share of domestic coal use for generation, up from 51 percent in 2003. Most of the low-sulfur coal used in 2025 is projected to come from the West, primarily the Powder River Basin and the Rocky Mountain regions. Projected declines in transportation rates contribute to the expected growth in sales of western low-sulfur coal, for which transportation costs are a relatively large part of delivered costs—typically over 60 percent for coal originating from the Powder River Basin, compared with under 25 percent for Central Appalachian coal.

Despite tighter emissions limits in CAAA90 Phase 2, the market for higher sulfur coals will continue in some regions, with 27 gigawatts of capacity expected to be retrofitted with scrubbers by 2025. Although use of higher sulfur coals at unscrubbed plants is expected to decline, their use at retrofitted or new units is projected to increase from 2003 levels.

Average Minemouth Coal Prices Are Not Projected To Rise Significantly

Figure 104. Average minemouth price of coal by region, 1990-2025 (2003 dollars per short ton)



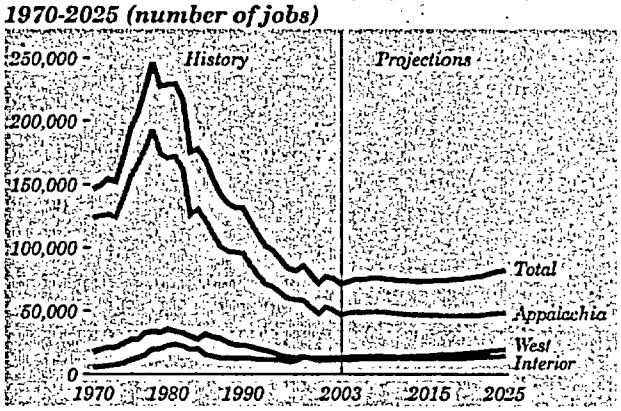
Between 1990 and 1999, the average minemouth price of coal declined by 4.9 percent per year, from $28.26 per ton (2003 dollars) to $18.01 per ton (Figure 104). Increases in U.S. coal mining productivity of 6.3 percent per year during the period helped to reduce mining costs and contributed to the decline in prices. Since 1999, growth in U.S. coal mining productivity has slowed to 1.3 percent per year, and minemouth coal prices have remained virtually unchanged despite some short-term fluctuations. The average in 2003 was $17.93 per ton.

Minemouth coal prices are projected to rise initially in the *AEO2005* reference case, primarily in response to strong growth in the demand for coal in the electric power sector. After 2005, when natural gas prices are in decline, natural-gas-fired generating capacity becomes more competitive, and coal demand grows more slowly. The combination of moderate growth in demand, improvements in mining productivity, and a continuing shift to low-cost coal from Wyoming's Powder River Basin leads to a projected decline in the average minemouth price, from $18.61 per ton in 2005 to around $17.00 per ton shortly after 2010, and it continues at about that level through 2020. After 2020 the price is projected to increase to $18.26 per ton in 2025, as rising natural gas prices and the need for baseload generating capacity result in the construction of new coal-fired generating capacity.

Increases in coal production in the Interior and Western supply regions, combined with limited improvement in coal mining productivity, result in projected minemouth price increases of 0.8 and 0.9 percent per year, respectively, in those regions from 2003 to 2025.

Coal Mine Employment Is Expected To Remain Near Current Levels

Figure 105. U.S. coal mine employment by region, 1970-2025 (number of jobs)



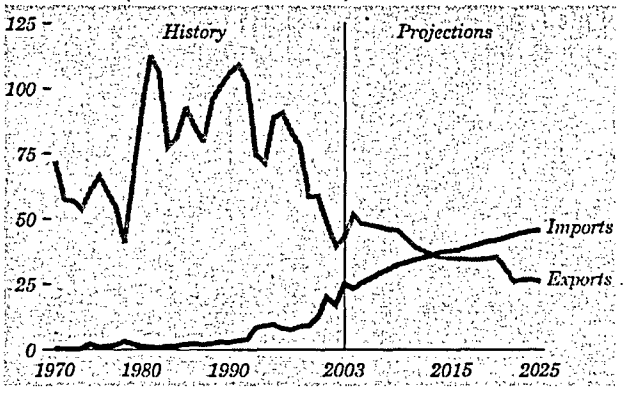
Most jobs in the U.S. coal industry remain east of the Mississippi River, mainly in the Appalachian region (65 percent of total mining jobs in 2003). Most coal production, however, occurs west of the Mississippi River (56 percent in 2003), with the major share from the Powder River Basin. As coal demand increases, pressure to keep prices low will shift more production to mines with higher labor productivity. Large surface mines in the Powder River Basin take advantage of economies of scale, using large earth-moving equipment and combining adjacent mines to increase operating flexibility. Underground mines in northern Appalachia, the Illinois Basin, and the Rocky Mountain region use highly productive and increasingly automated longwall equipment to maximize production while reducing the number of miners required.

Labor productivity is expected to continue to improve in most regions but at a decreasing rate. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

About 11,000 additional jobs are projected to be created in the U.S. coal industry by 2025 (Figure 105). The new mining jobs will be in the most productive surface and underground mines, but jobs will be lost in the less productive mines of Central Appalachia.

Declining U.S. Coal Exports, Rising Imports Are Projected

Figure 106. U.S. coal exports and imports, 1970-2025 (million short tons)



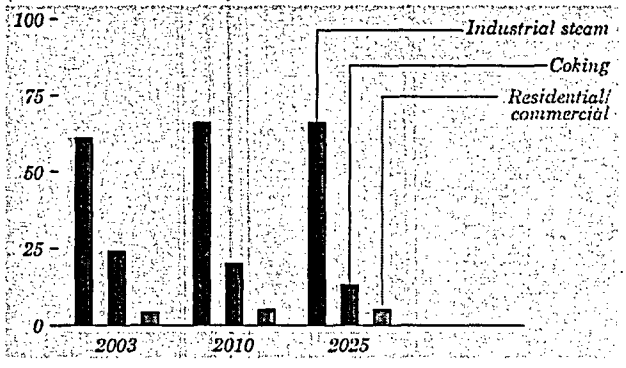
U.S. coal exports declined steadily from 1996 through 2002, from 90 million tons to 40 million tons, despite a substantial increase in world coal trade from 503 million tons in 1996 to 656 million tons in 2002. During the same period, low-cost supplies of coal from China, Colombia, Indonesia, Russia, and Australia satisfied much of the growth in international demand for steam coal, while low-cost supplies of coking coal from Australia supplanted substantial amounts of U.S. coking coal in world markets. Since 2002, U.S. exports have rebounded, however, including increases in exports of steam coal to Canada in 2003 and to overseas customers in 2004.

Although U.S. coal exports are projected to remain above the 2003 level for the next several years, the U.S. share of total world coal trade is ultimately projected to fall from 6 percent in 2003 to 3 percent in 2025, as international competition intensifies and imports of coal to Europe and the Americas grow more slowly or decline. Following a projected rise in 2004, U.S. coal exports decline gradually in the forecast, from 43 million tons in 2003 to 26 million tons in 2025 (Figure 106).

U.S. imports of low-sulfur coal are projected to grow from 25 million tons in 2003 to 46 million tons in 2025. The addition and expansion of existing coal import facilities and the need to meet tighter emission targets are expected to make coal imports an increasingly attractive option for U.S. coal-fired power plants located near the Gulf Coast and the Atlantic seaboard. Much of the additional import tonnage is expected to originate from mines in Colombia, Venezuela, and Indonesia.

U.S. Consumption of Coking Coal Declines in the Forecast

Figure 107. Coal consumption in the industrial and buildings sectors, 2003, 2010, and 2025 (million short tons)



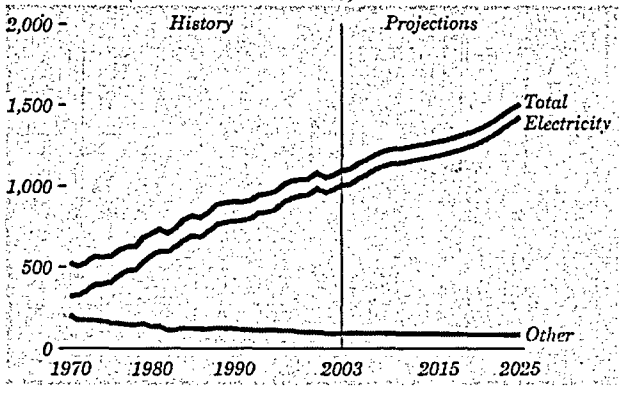
Although most coal is used to generate electricity, 91 million tons (8 percent of consumption) is used annually in the industrial and buildings (residential and commercial) sectors (Figure 107). Steam coal is used in manufacturing paper, chemical, food, and textile products. The key use of coal in these sectors is to produce process steam, which provides heat and mechanical power. Electricity is often produced in conjunction with steam (cogeneration) and is used in the manufacturing process or sold into the electric power grid. Coal is used by the cement industry as an important source of fuel for dry kilns, and the chemical industry also uses coal as a feedstock. Consumption of steam coal in the industrial sector is projected to remain relatively constant in the forecast.

Coal is also used to produce coke, which in turn is used as a source of energy and as a raw material input at blast furnaces to produce iron. Coking coal is the most important source of energy in the iron and steel industry, accounting for 51 percent of the energy consumed in 2003. In the forecast, U.S. consumption of coking coal declines by 2.7 percent per year, from 24 million tons in 2003 to 13 million tons in 2025, as production shifts from coke-based production at integrated steel mills to electric arc furnaces. Coking coal's share of total energy use in the U.S. steel industry is projected to decline to 35 percent in 2025.

Although coal is used to generate much of the electricity consumed in the buildings sectors, its direct consumption accounts for only a minor portion of total energy use in those sectors. Annual coal consumption in the building sectors is projected to remain constant at about 5 million tons.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 108. Electricity and other coal consumption, 1970-2025 (million short tons)



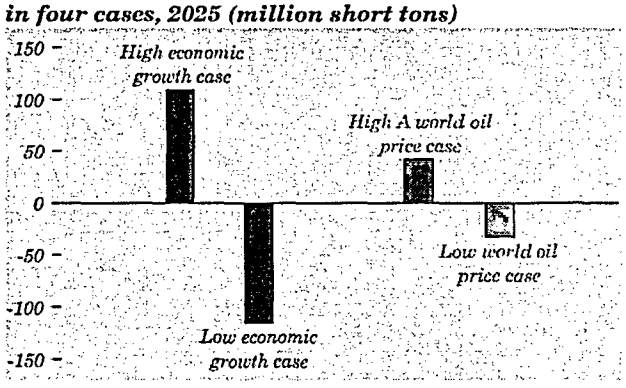
Domestic coal demand is projected to increase by 413 million tons (38 percent) in the reference case forecast, from 1,095 million tons in 2003 to 1,508 million tons in 2025 (Figure 108). Of all the coal consumed in 2003, 92 percent was used for electricity generation, and that share is expected to rise to 94 percent in 2025. Coal use for electricity generation is expected to increase on average, by 1.6 percent per year from 2003 to 2025. Coal accounted for 51 percent of U.S. electricity generation (including combined heat and power) in 2003 and is projected to account for 50 percent in 2025, when more natural gas is expected to be used for generation.

Overall, coal consumption in the electric power sector is expected to grow as existing coal-fired plants are used more intensively and new ones are added after 2011. Nationally, capacity utilization for coal plants (excluding combined heat and power) is expected to rise from 72 percent in 2003 to 83 percent in 2025. Only 3 gigawatts of coal-fired capacity is expected to be retired in the forecast, and 87 gigawatts of new capacity, including 16 gigawatts of integrated gasification combined cycle, is expected to be added—more than half in regions west of the Mississippi River.

New coal-fired generating capacity is expected to result in large increases in coal consumption in the Mountain and East South Central Census Divisions. Western coal will continue to account for the largest share of coal use for electricity generation in the Mountain Census Division, and its share in the East South Central Division is projected to increase from 32 percent in 2003 to 37 percent in 2025.

Higher Economic Growth Stimulates Electricity Generation from Coal

Figure 109. Projected variation from the reference case projection of total U.S. coal demand in four cases, 2025 (million short tons)

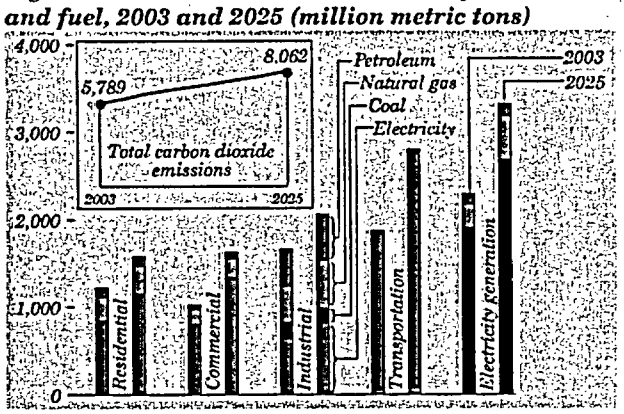


Domestic coal consumption in 2025 is projected to range from 1,393 million tons in the low economic growth cases to 1,617 million tons in the high economic growth case, with coal use for electricity generation making up 219 million tons (98 percent) of the difference. The most significant impact on coal occurs in the later years of the forecast period, when economic conditions influence plans for new electricity generation capacity. Projected additions of coal-fired capacity from 2003 to 2025 are 39 gigawatts higher in the high economic growth case than in the reference case and 37 gigawatts lower in the low economic growth case. Regionally, the Mountain and East South Central Census Divisions show the largest increases in coal consumption in the high economic growth case and the largest declines in the low economic growth case relative to the reference case.

Compared with the economic growth cases, a smaller impact on coal consumption is expected in the world oil price cases (Figure 109). The projection for total U.S. coal demand in 2025 is 33 million tons lower in the low world oil price case than in the reference case and 42 million tons higher in the high A world oil price case. Low oil prices encourage electricity generation from existing oil-fired units, reducing generation from other fuels, including coal. For electricity generation, the low oil price case projects 34 million tons less coal use in 2025 than is projected in the reference case. In the high A world oil price case, elevated prices for low-sulfur distillate are projected to stimulate the coal-to-liquids market. In 2025, 48 million tons of coal is projected to be consumed at coal-to-liquids plants, yielding 62 million barrels of fuel liquids and 34 billion kilowatthours of electricity.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 110. Carbon dioxide emissions by sector and fuel, 2003 and 2025 (million metric tons)

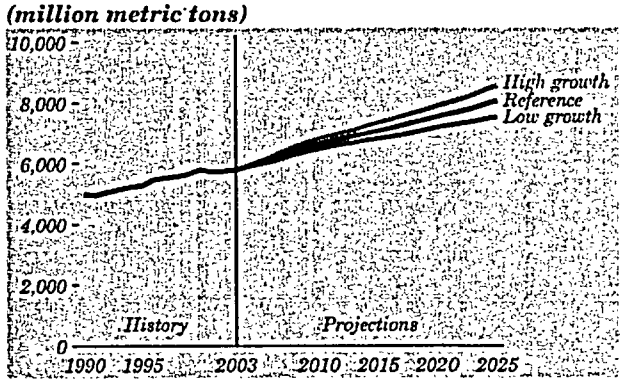


Carbon dioxide emissions from energy use are projected to increase on average by 1.5 percent per year from 2003 to 2025, to 8,062 million metric tons (Figure 110). Emissions per capita are projected to grow by 0.7 percent per year. New carbon dioxide mitigation programs, more rapid improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.2 percent per year, reflecting increased electrification and penetration of computers, electronics, and appliances in the sector. Significant growth in office equipment and computers, as well as floorspace, is also projected for the commercial sector, and carbon dioxide emissions from the sector are projected to increase by 2.1 percent per year from 2003 to 2025. Industrial emissions are projected to grow by 1.0 percent per year, as shifts to less energy-intensive industries and efficiency gains help to moderate the effect of growth in energy use. In the transportation sector, carbon dioxide emissions grow at an annual rate of 1.8 percent. Increases in highway, rail, and air travel are partially offset by efficiency improvements in rail freight and aircraft, but passenger vehicle fuel economy is projected to increase only slightly above 2003 levels. In the electric power sector, continued reliance on coal and growth in natural-gas-fired generation result in a projected average increase in carbon dioxide emissions of 1.7 percent per year and an increase in the sector's share of total emissions to 41 percent in 2025 from 39 percent in 2003.

Emissions Projections Change With Economic Growth Assumptions

Figure 111. Carbon dioxide emissions in three economic growth cases, 1990-2025 (million metric tons)



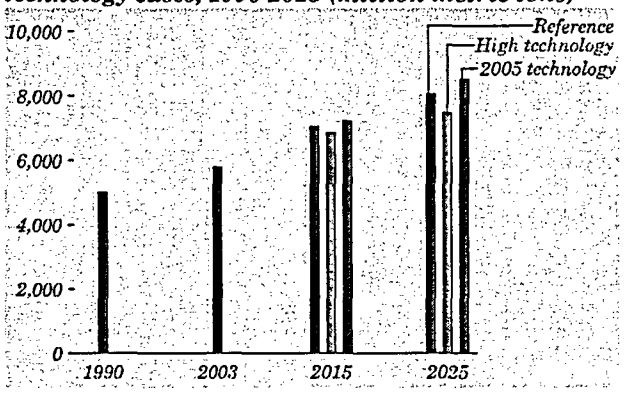
The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. GDP growth in the high growth case averages 3.6 percent per year from 2003 to 2025, compared with 3.1 percent per year in the reference case. In the low economic growth case, GDP growth averages 2.5 percent per year.

Higher projections for manufacturing output and income increase the demand for energy services in the high economic growth case, and projected energy consumption in 2025 is 6 percent higher than in the reference case. As a result, carbon dioxide emissions are projected to be 6 percent higher than in the reference case in 2025, at 8,561 million metric tons (Figure 111). Total energy intensity, measured as primary energy consumption per dollar of GDP, declines by 1.9 percent per year from 2003 to 2025 in the high growth case, as compared with 1.6 percent per year in the reference case. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity for turnover in the stock of energy-using technologies, adding new equipment and increasing the overall efficiency of the capital stock.

Projected total energy consumption in 2025 is 6 percent lower in the low economic growth case than in the reference case, and carbon dioxide emissions in 2025 are 7 percent lower, at 7,530 million metric tons. Energy intensity is projected to decline at an average rate of 1.4 percent per year from 2003 to 2025 in the low economic growth case.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 112. Carbon dioxide emissions in three technology cases, 1990-2025 (million metric tons)

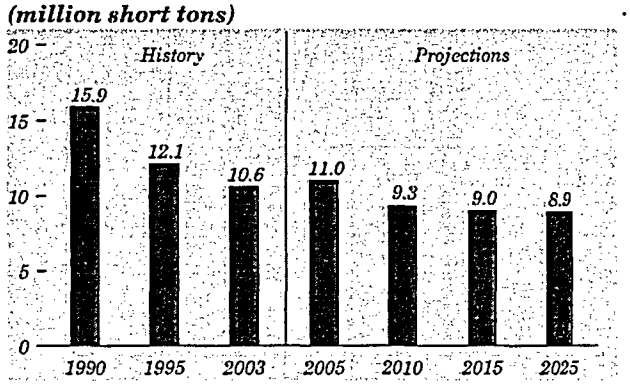


The reference case assumes continuing improvement in energy-consuming and producing technologies, consistent with historic trends, as a result of ongoing research and development. In the high technology case it is assumed that increased spending on research and development will result in earlier introduction, lower costs, and higher efficiencies for end-use technologies than assumed in the reference case. The costs and efficiencies of advanced fossil-fired and new renewable generating technologies are also assumed to improve from reference case values [*143*]. Energy intensity is expected to decline on average by 1.9 percent per year through 2025 in the high technology case, as compared with 1.6 percent in the reference case. As a result, energy consumption is projected to be 5 percent lower than in the reference case in 2025, at 126 quadrillion Btu, and carbon dioxide emissions are projected to be 7 percent lower than in the reference case, at 7,471 million metric tons (Figure 112).

The 2005 technology case assumes that future equipment choices will be made from the equipment and vehicles available in 2005; that new building shell and plant efficiencies will remain at their 2005 levels; and that advanced generating technologies will not improve over time. Energy efficiency improves in the 2005 technology case as new equipment is chosen to replace older stock and the capital stock expands, and energy intensity declines by 1.4 percent per year from 2003 to 2025. Energy consumption reaches 140 quadrillion Btu in 2025 in the 2005 technology case, and carbon dioxide emissions in 2025 are projected to be 6 percent higher than in the reference case, at 8,519 million metric tons.

Sulfur Dioxide Emissions Are Cut in Response to Tightening Regulations

Figure 113. Sulfur dioxide emissions from electricity generation, 1990-2025 (million short tons)



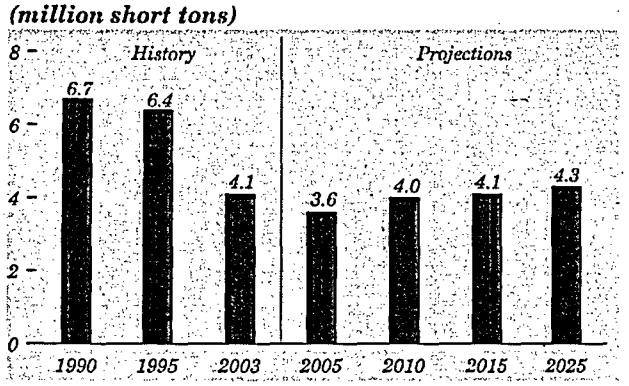
CAAA90 called for annual emissions of SO_2 by electricity generators in the power sector to be reduced to approximately 12 million short tons in 1996, 9.48 million short tons per year from 2000 to 2009, and 8.95 million short tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million short tons per year is not expected to be reached until after 2012. Coal combustion accounts for more than 95 percent of the SO_2 produced by generators.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, which began in 1995, 261 generating units at 110 plants were issued tradable emissions allowances that permitted their SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances could also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by most generators, and only about 12 gigawatts of capacity had been retrofitted with scrubbers by 1995.

Power companies have announced plans to add scrubbers to 22 gigawatts of capacity in order to comply with State or Federal initiatives. About 6 gigawatts of additional capacity is projected to be retrofitted with scrubbers. SO_2 emissions are projected to drop from 10.6 million short tons in 2003 to 8.9 million tons in 2025 (Figure 113). The SO_2 emission allowance price is projected to rise to near $275 per ton in 2010 as banked allowances are used and to remain between $250 and $325 per ton from 2010 through 2025.

Nitrogen Oxide Emissions Are Projected To Fall in the Near Term

Figure 114. Nitrogen oxide emissions from electricity generation, 1990-2025 (million short tons)



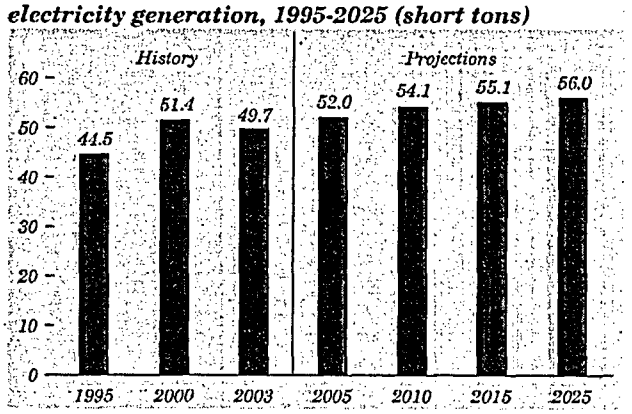
NO_x emissions from electricity generation in the U.S. power sector are projected to fall in the short term as new regulations take effect (Figure 114). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months.

For several years, the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal-fired power plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force plant operators to reduce emissions by more than required under current rules.

The Ozone Transport Rule called for capping NO_x emissions in Midwestern and Eastern States, and limits have been finalized for 19 States. The limits, which apply to NO_x emissions during the 5-month summer season in the 19 States covered, are expected to stimulate additions of emission control equipment to some existing plants. National NO_x emissions are projected to increase from 4.1 million short tons in 2003 to 4.3 million short tons in 2025. Due to the geographical restriction of the cap, coal use and NO_x emissions are expected to increase at plants outside the 19 covered States. Overall, selective catalytic reduction equipment is projected to be added to approximately 74 gigawatts of capacity, and NO_x allowance prices are projected to range from roughly $4,000 to $5,600 per ton between 2005 and 2025.

Mercury Emissions Are Expected To Grow With Increased Coal Use

Figure 115. Mercury emissions from electricity generation, 1995-2025 (short tons)



Mercury is a metallic element that occurs naturally in all types of coal. Its concentration can vary significantly by coal type and origin, even within a single mine. There are no Federal regulations on mercury emissions from power plants, but the EPA is considering mandatory limits. Several States have adopted or are considering mercury control regulations for power plants within their jurisdictions.

Emissions of mercury depend on a variety of site-specific factors, including the amounts of mercury and other compounds (such as chlorine) in the coal, the boiler type and configuration, and the presence of pollution control equipment such as fabric filters, electrostatic precipitators, flue gas desulfurization, and selective catalytic control equipment. Technologies that remove SO_2 and NO_x have shown promise in removing mercury from bituminous coals but have not performed as well with lower ranked coals [*144*]. The U.S. Department of Energy, together with industry partners, is sponsoring research and development programs on advanced technologies to reduce mercury emissions from power plants.

The *AEO2005* reference case assumes no regulation of mercury emissions in the electricity generation sector through 2025, and the average mercury content of coal burned at power plants is assumed to stay relatively constant at about 7.4 pounds per trillion Btu of energy input to coal-fired electricity production. Consequently, with coal use for electricity generation projected to increase, total mercury emissions from power plants are also projected to increase, from 49.7 short tons in 2003 to 56.0 short tons in 2025 (Figure 115).

Forecast Comparisons

Only one other organization—Global Insight, Incorporated (GII)—produces a comprehensive energy projection with a time horizon similar to that of *AEO2005*. Other organizations address one or more aspects of the energy markets. The most recent projection from GII, as well as other forecasts that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2005* projections.

Economic Growth

In *AEO2005* the projected growth in real GDP, based on 2000 chain-weighted dollars, is 3.1 percent per year from 2003 to 2025—slightly higher than the 3.0-percent average annual growth projected in *AEO2004* (Table 32). The *AEO2005* forecast is based on the May 2004 long-range forecast and the August short-term forecast of GII, modified to reflect EIA's view on energy prices, demand, and production.

The average annual GDP growth rate projections for the United States from 2003 through 2009 range from 3.4 to 3.6 percent. The *AEO2005* reference case and GII project the lowest rate at 3.4 percent, and the Office of Management and Budget (OMB) projects the highest rate at 3.6 percent, followed by the Congressional Budget Office (CBO) and Oxford Economic Forecasting (OEF) at 3.5 percent. When the projection period is extended to 2014, the uncertainty in the GDP growth rate is reflected by a widening of the range of GDP growth rate projections (3.1 to 3.5 percent). While *AEO2005* remains in the lower half of the range, the CBO projection reflects a considerable slowing of GDP growth during the 2010 to 2014 period. Because few commercial or private forecast organizations project GDP growth rates for the United States to 2025, comparisons over the entire period from 2003 to 2025 are not readily available. The *AEO2005* reference case projection reflects a slowing of the GDP growth rate after 2015, consistent with an expected slowing of population growth.

World Oil Prices

Comparisons with other oil price forecasts are shown in Table 33. The world oil price measure varies by forecast. In some projections, the measure is the spot price for WTI, Brent, or a basket of crude oils. *AEO2005* uses the annual average U.S. refiner's acquisition cost of imported crude oil, including transportation and fees. There is no simple way to put the forecasts for oil prices on a common basis. The range between the *AEO2005* low and high B world oil price cases spans the range of published forecasts. In fact, the *AEO2005* high B world oil price case is considerably above all the other forecasts for 2025.

Recent variability in crude oil prices demonstrates the uncertainty inherent in forecasting crude oil markets, which generally widens as the time horizon extends into the future. The oil price paths proffered by several organizations (Table 33), including *AEO*, illustrate the uncertainty. For example, for 2010, the price range in the forecasts is from a low of about $22 per barrel projected by Altos Partners (Altos) to a high of almost $35 per barrel projected by Petroleum Industry Research Associates, Inc. (PIRA). The range in the forecasts for 2025 is somewhat narrower but

Table 32. Forecasts of annual average economic growth, 2003-2025

Forecast	Average annual percentage growth		
	2003-2009	2003-2014	2003-2025
AEO2004	3.5	3.2	3.0
AEO2005			
Reference	3.4	3.3	3.1
Low growth	2.9	2.8	2.5
High growth	4.1	3.9	3.6
GII	3.4	3.2	3.1
OMB	3.6	NA	NA
CBO	3.5	3.1	NA
OEF	3.5	3.5	NA

NA = not available.

Table 33. Forecasts of world oil prices, 2010-2025 (2003 dollars per barrel)

Forecast	2010	2015	2020	2025
AEO2004 (reference case)	24.53	25.44	26.41	27.40
AEO2005				
Reference	25.00	26.75	28.50	30.31
High A world oil price	33.99	34.24	36.74	39.24
High B world oil price	37.00	40.67	44.33	48.00
October oil futures	30.99	32.33	33.67	35.00
Low world oil price	20.99	20.99	20.99	20.99
GII	27.08	25.58	26.66	27.12
IEA (reference scenario)	23.25	25.37	27.48	29.07
IEA (high oil price case)	37.00	37.00	37.00	37.00
Altos	21.92	22.67	23.93	24.60
PEL	25.00	27.00	27.00	29.00
PIRA	34.75	39.15	NA	NA
DB	24.00	24.00	24.00	24.00
EEA	26.58	25.55	24.93	NA
SEER	26.13	28.40	28.25	29.00
EVA	28.99	28.39	30.97	34.77

NA = not available.

still substantial, from a low of $24 per barrel projected by Deutsche Bank, A.G. (DB) to a high of nearly $35 per barrel projected by Energy Ventures Analysis, Incorporated (EVA).

Total Energy Consumption

The *AEO2005* forecast of end-use sector energy consumption shows higher growth for petroleum and natural gas than occurred from 1980 to 2003 but lower projected growth in electricity consumption (Table 34). Much of the projected growth in petroleum consumption is driven by increased demand in the industrial sector for petrochemical and manufacturing applications as economic activity expands, and in the transportation sector as improvements in efficiency fail to offset increases in miles traveled. Natural gas consumption is expected to increase in the residential, commercial, and industrial sectors as environmental and economic pressures benefit natural gas at the expense of petroleum and coal consumption. Coal consumption in those end-use sectors is expected to decline slightly as a result of increased fuel switching and growing concern about emissions.

Electricity is expected to remain the fastest growing source of delivered energy. Its growth does not outpace historical rates, however, because many traditional uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. The *AEO2005* projections are generally consistent with the outlook from GII; however, GII projects slower growth in natural gas consumption, electricity consumption, and electricity losses, as well as slightly faster growth in petroleum consumption, resulting from differences in relative prices and projected growth in each sector.

Table 34. Forecasts of average annual growth rates for energy consumption, 2003-2025 (percent)

		Projections	
Energy use	*History 1980-2003*	*AEO2005*	*GII*
*Petroleum**	0.8	1.5	1.6
*Natural gas**	0.2	1.0	0.7
*Coal**	-1.7	-0.6	-0.4
Electricity	2.2	1.9	1.6
Delivered energy	0.7	1.4	1.3
Electricity losses	1.9	1.4	0.9
Primary energy	1.0	1.4	1.2

**Excludes consumption by electricity generators in the electric power sector but includes consumption for end-use combined heat and power generation.*

Electricity

The *AEO2005* projections for the electricity generation sector assume that wholesale electricity markets in most U.S. regions will be restructured, resulting in average wholesale electricity prices that approach long-run marginal costs. The same cannot be said for retail markets at the State level: as of 2003, only 17 States and the District of Columbia had competitive retail markets in operation. Further, a number of States have delayed opening competitive retail markets, Arkansas has repealed retail restructuring, and California has suspended restructuring. The *AEO-2005* cases assume that no additional retail markets will be restructured, but that partial restructuring (particularly in wholesale markets) will lead to increased competition in the electric power industry, lower operating and maintenance costs, and early retirement of inefficient generating units.

Comparison of the *AEO2005* reference case, GII, and EVA forecasts shows some variation in projected electricity sales (Table 35). The forecasts for total electricity sales in 2025 range from 4,982 billion kilowatthours (GII) to 5,396 billion kilowatthours (EVA). The rate of demand growth ranges from 1.6 percent (GII) to 2.0 percent (EVA). All price forecasts reflect competition in wholesale markets and slow growth in electricity demand relative to GDP growth, exerting downward pressure on real electricity prices through 2025. Rising natural gas prices balance some of the downward pressure and tend to push electricity prices up in the later years of the forecasts.

The *AEO2005* reference case projects a slight decline in real electricity prices over the full period of the forecast (except for the industrial sector), although average prices increase slightly during the last several years as capacity margins tighten and natural gas prices climb. In contrast, GII projects a decline in electricity prices over the second half of the forecast as lower natural gas prices to generators ($4.23 per million Btu in the GII forecast, compared with $5.44 per million Btu in the *AEO2005* reference case in 2025) contribute to a small decrease in average electricity prices, from 7.2 cents per kilowatthour in 2015 to 7.1 cents per kilowatthour in 2025. The higher natural gas price projected in the *AEO2005* reference case leads to an increase in average electricity price, from 6.9 cents per kilowatthour in 2015 to 7.3 cents per kilowatthour in 2025.

Both the *AEO2005* reference case and GII projections include some planned capacity additions in the near

Table 35. Comparison of electricity forecasts, 2015 and 2025 (billion kilowatthours, except where noted)

Projection	2003	AEO2005			Other forecasts				
		Reference	Low economic growth	High economic growth	GII	EVA	EEA	SEER	PIRA
					2015				
Average end-use price (2003 cents per kilowatthour)	7.4	6.9	6.7	7.1	7.2	NA	NA	NA	NA
Residential	8.7	8.1	7.7	8.3	8.3	8.1	NA	NA	NA
Commercial	7.9	7.3	6.9	7.5	7.7	7.4	NA	NA	NA
Industrial	5.1	5.0	4.7	5.2	4.8	4.7	NA	NA	NA
Net energy for load, including CHP	3,857	4,912	4,762	5,082	4,667	5,131	4,913	4,472	4,706
Coal	1,971	2,306	2,269	2,354	2,325	2,190	2,255	2,230	2,115
Oil	135	150	146	149	45	22	77	97	97
Natural gas [a]	632	1,171	1,077	1,285	1,035	1,523	1,306	815	1,237
Nuclear	764	826	826	826	800	822	813	794	805
Hydroelectric/other [b]	350	438	426	448	446	538	383	356	430
Nonutility sales to grid [c]	28	59	53	67	NA	NA	41	179	NA
Net imports	5	21	18	20	16	36	38	NA	23
Electricity sales	3,482	4,430	4,295	4,583	4,244	4,571	4,415	NA	NA
Residential	1,280	1,584	1,569	1,604	1,569	1,673	1,561	NA	NA
Commercial/other [d]	1,233	1,680	1,657	1,703	1,539	1,699	1,588	NA	NA
Industrial	969	1,166	1,069	1,276	1,136	1,200	1,266	NA	NA
Capability, including CHP (gigawatts) [e]	948	1,002	981	1,030	989	1,074	1,074	NA	NA
Coal	314	320	316	325	347	330	335	NA	NA
Oil and natural gas	415	455	439	476	408	329	500	NA	NA
Nuclear	99	102	102	102	100	102	102	NA	NA
Hydroelectric/other	119	125	123	126	134	312	138	NA	NA
					2025				
Average end-use price (2003 cents per kilowatthour)	7.4	7.3	7.0	7.6	7.1	NA	NA	NA	NA
Residential	8.7	8.3	8.0	8.7	8.2	8.1	NA	NA	NA
Commercial	7.9	7.6	7.3	8.1	7.7	7.3	NA	NA	NA
Industrial	5.1	5.4	5.1	5.7	4.7	4.7	NA	NA	NA
Net energy for load, including CHP	3,857	5,780	5,444	6,117	5,475	6,100	NA	5,309	NA
Coal	1,971	2,890	2,613	3,179	2,932	2,597	NA	2,578	NA
Oil	135	163	158	168	26	19	NA	94	NA
Natural gas [a]	632	1,406	1,371	1,409	1,267	1,831	NA	1,181	NA
Nuclear	764	830	830	830	773	888	NA	816	NA
Hydroelectric/other [b]	350	480	461	519	464	727	NA	398	NA
Nonutility sales to grid [c]	28	91	74	110	NA	NA	NA	242	NA
Net imports	5	11	11	12	13	40	NA	NA	NA
Electricity sales	3,482	5,219	4,914	5,518	4,982	5,396	NA	NA	NA
Residential	1,280	1,810	1,748	1,850	1,851	2,007	NA	NA	NA
Commercial/other [d]	1,233	2,123	2,047	2,196	1,846	2,058	NA	NA	NA
Industrial	969	1,286	1,119	1,472	1,285	1,331	NA	NA	NA
Capability, including CHP (gigawatts) [e]	948	1,190	1,129	1,248	1,140	1,246	NA	NA	NA
Coal	314	398	361	438	435	390	NA	NA	NA
Oil and natural gas	415	555	535	567	466	387	NA	NA	NA
Nuclear	99	103	103	103	100	110	NA	NA	NA
Hydroelectric/other	119	134	130	141	139	358	NA	NA	NA

[a]Includes supplemental gaseous fuels. [b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, plus a small quantity of petroleum coke. [c]For *AEO2005*, includes only net sales from combined heat and power plants. [d]"Other" includes sales of electricity to government, railways, and street lighting authorities. [e]EIA capacity is net summer capability, including combined heat and power plants. GII capacity is nameplate, excluding cogeneration plants. [f]EVA "other" includes all CHP.

CHP = combined heat and power. NA = not available.

Sources: ***AEO2005:*** AEO2005 National Energy Modeling System, runs AEO2005.D102004A (reference case), LM2005.D102004A (low economic growth case), and HM2005.D102004A (high economic growth case). **GII:** Global Insight, Inc., *Summer 2004 U.S. Energy Outlook* (August 2004). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2004). **SEER:** Strategic Energy and Economic Research, Inc., *2004 Energy Outlook* (October 2004). **PIRA:** PIRA Research Group (October 2004).

term, with the *AEO2005* reference case expecting about 28 gigawatts through 2005 and GII expecting about 14 gigawatts. Virtually all the projected capacity additions are natural gas fired. These two forecasts project that prices will fall in the near term as a result of excess total capacity.

All the forecasts except for GII project that demand will grow fastest in the commercial sector, and that more cycling and baseload capability will be built than peaking units. All the forecasts show significant net additions to coal-fired capacity: 84 gigawatts through 2025 in the *AEO2005* reference case and 121 gigawatts through 2025 in the GII forecast. Both GII and the *AEO2005* reference case project no nuclear retirements; however, EVA projects 8 gigawatts of nuclear capacity additions by 2025.

The fuel mix in the EVA forecast differs from that in the *AEO2005* reference case and the other forecasts. All the forecasts, except for EVA, project that coal will provide about one-half and natural gas about one-quarter of the growth in electricity generation over the forecast period. The EVA forecast assumes that legislation similar to the Clear Skies Act—including further restrictions on SO_2, NO_x, and mercury emissions—will be in effect by 2010. The EVA forecast also includes a tax of $5 per ton on carbon dioxide emissions, beginning in 2013. *AEO2005* does not assume either passage of the Clear Skies Act or any carbon tax throughout the forecast horizon. In the EVA forecast, the combination of further environmental restrictions and a tax on carbon dioxide leads to greater growth in hydroelectric generation.

Natural Gas

There are considerable differences among published forecasts of natural gas prices, production, consumption, and imports (Table 36). The differences highlight the uncertainty of future market trends. Because the forecasts depend heavily on the underlying assumptions that shape them, the assumptions made in each forecast should be considered when different projections are compared.

Over the period from 2007 to 2025, the *AEO2005* reference case is within the range of projections for total natural gas consumption in the other forecasts. The lowest projected totals for natural gas consumption in 2005 are from the DB forecast, and the highest are from the EVA forecast. For residential and commercial natural gas consumption, DB projects the strongest growth from 2003 to 2025, and the GII forecast has the lowest projected consumption levels. The *AEO2005* reference case projections for 2025 fall in the high end of the range for residential consumption and in the mid-range for commercial consumption. Natural gas consumption in the industrial and electric power sectors is more difficult to compare, given potential definitional differences. The EVA forecast shows the fastest growth in natural gas consumption from 2003 to 2025 in combined totals for the industrial and electric power sectors, whereas the DB forecast shows much slower growth than the other forecasts.

Natural gas for domestic consumption is supplied by domestic production and net imports. All forecasts show domestic production providing a decreasing share of total natural gas supply. The Altos forecast shows a smaller shift in that direction, with significantly lower net imports and significantly higher domestic production. Three of the forecasts—*AEO2005* reference case, GII, and DB—project that net imports will supply about 30 percent of end-use consumption by 2025. EVA projects that 36 percent of consumption will be supplied by net imports, Strategic Energy & Economic Research, Incorporated (SEER) projects 26 percent, and Altos 18 percent (for Altos, the percentage is calculated as net imports divided by the sum of production and net imports).

The volume of net imports varies significantly among the forecasts, as does the mix of net imports. GII, SEER, and Altos expect a decline in net pipeline imports of more than 50 percent between 2003 and 2025, the *AEO2005* reference case projects a more modest decline of about 20 percent, and EVA anticipates an increase in net pipeline imports of 30 percent (DB is not included in this comparison because of definitional differences). All the forecasts project strong growth in LNG imports, with net LNG imports in 2025 ranging from 4.6 trillion cubic feet in the Altos forecast to 8.3 trillion cubic feet in the EVA forecast (again, DB is excluded from this comparison). The *AEO2005* reference case is more conservative than most of the forecasts for LNG imports: GII, EVA, and SEER all project higher levels of LNG imports in 2025 than are projected in the *AEO2005* reference case.

Wellhead natural gas price projections for 2025 in the *AEO2005* reference case are higher than those in all the other available forecasts, with the exception of Altos. Wellhead natural gas prices in the EEA and PIRA forecasts exceed those in the *AEO2005* reference case in 2015. Of the three forecasts that project

Table 36. Comparison of natural gas forecasts, 2015 and 2025 (trillion cubic feet, except where noted)

Projection	2003	AEO2005 reference case	Other forecasts						
			GII[a]	EEA[b]	EVA	PIRA	DB	SEER	Altos
					2015				
Lower 48 wellhead price (2003 dollars per thousand cubic feet)	4.98	4.16	3.84	4.69	3.71	5.14c	3.66	3.90	3.92
Dry gas production[d]	19.07	20.77	19.28	21.39[e]	20.22[f]	17.34	21.24	20.24	22.48
Net imports	3.30	7.02	6.94	7.97	9.82	9.77	3.76	6.98	5.78
Pipeline	2.86	2.69	1.63	2.94	4.64	4.66	2.75[g]	2.71	1.15
LNG[h]	0.44	4.33	5.31	5.03	5.18	5.11	1.01 i	4.26	4.63
Consumption	21.97	27.96	26.29	28.87	29.72	27.22	24.99	27.21	NA
Residential	5.10	5.74	5.40	5.75	5.52	5.39	5.71	5.57	NA
Commercial	3.14	3.58	3.24	3.56	3.68	3.56	3.65	3.58	NA
Industrial[j]	7.03	8.26	7.67[k]	7.73[l]	8.00[m]	6.30[n]	7.90	8.09	NA
Electricity generators[o]	4.93	8.39	8.01[p]	9.59[q]	10.24	9.88[r]	5.93	7.81	NA
Other[s]	1.77	1.99	1.96	2.23	2.28[t]	2.09	1.81	2.17	NA
End-use prices (2003 dollars per thousand cubic feet)									
Residential	9.62	8.45	8.36	8.29	NA	NA	NA	8.89	NA
Commercial	8.32	7.54	7.22	7.50	NA	NA	NA	7.63	NA
Industrial[j]	5.72	4.96	5.15[u]	5.79	NA	NA	NA	5.25	NA
Electricity generators[o]	5.55	4.90	4.21	5.49	NA	NA	NA	4.77	NA
					2025				
Lower 48 wellhead price (2003 dollars per thousand cubic feet)	4.98	4.79	3.96	NA	3.98	NA	3.66	4.26	5.78
Dry gas production[d]	19.07	21.83	20.43	NA	21.51[f]	NA	18.84	21.99	24.10
Net imports	3.30	8.66	8.49	NA	12.01	NA	8.19	7.84	5.15
Pipeline	2.86	2.29	0.97	NA	3.72	NA	4.75[g]	1.31	0.51
LNG[h]	0.44	6.37	7.52	NA	8.29	NA	3.44[i]	6.53	4.64
Consumption	21.97	30.67	29.00	NA	33.58	NA	27.03	29.83	NA
Residential	5.10	5.99	5.87	NA	5.88	NA	6.30	5.88	NA
Commercial	3.14	4.05	3.52	NA	4.07	NA	4.13	4.04	NA
Industrial[j]	7.03	9.00	8.06[k]	NA	8.96[m]	NA	8.72	8.95	NA
Electricity generators[o]	4.93	9.43	9.42[p]	NA	12.10	NA	6.23	8.60	NA
Other[s]	1.77	2.20	2.13	NA	2.57[t]	NA	1.64	2.35	NA
End-use prices (2003 dollars per thousand cubic feet)									
Residential	9.62	9.33	8.34	NA	NA	NA	NA	9.48	NA
Commercial	8.32	8.19	7.22	NA	NA	NA	NA	7.99	NA
Industrial[j]	5.72	5.63	5.22[u]	NA	NA	NA	NA	5.61	NA
Electricity generators[o]	5.55	5.55	4.31	NA	NA	NA	NA	5.13	NA

NA = not available.

[a]Summer 2004 (previously DRI-WEFA). Conversion factors: 1,000 cubic feet = 1.027 million Btu for production, 1.028 million Btu for end-use consumption, 1.019 million Btu for electric power. [b]The EEA projection shows a cyclical price trend; forecast values for an isolated year may be misleading. [c]Henry Hub daily cash natural gas price in 2003 dollars per thousand cubic feet. [d]Does not include supplemental fuels. [e]Includes Alaska production. [f]Wet natural gas production. [g]Includes net pipeline imports from Mexico, Canada, and the Bahamas. [h]Includes LNG imports into Florida via the Bahamas. [i]Includes net LNG imports into the United States only. [j]Includes consumption for combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public; excludes consumption by nonutility generators. [k]Excludes gas used in cogeneration or other nonutility generation. [l]Includes natural gas consumed in cogeneration. [m]Includes transportation fuel consumed in natural gas vehicles. [n]Excludes gas demand for nonutility generation. [o]Includes consumption of energy by electricity-only and CHP plants; includes small power producers and exempt wholesale generators. [p]Includes gas used in cogeneration or other nonutility generation. [q]Includes independent power producers and excludes cogenerators. [r]Equals the sum of gas demand for nonutility generation plus gas demand for utility generation. [s]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [t]Includes lease, plant, and pipeline fuel. [u]On-system sales or system gas (i.e., does not include gas delivered for the account of others).

Sources: **2003 and *AEO2005*:** AEO2005 National Energy Modeling System, run AEO2005.D102004A (reference case). **GII:** Global Insight, Inc., *U.S. Energy Outlook* (Summer 2004). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2004). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **PIRA:** PIRA Energy Group (October 2004). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 11, 2004. **Altos:** Altos North American Regional Gas Model (NARG) Base Case (September 2004).

end-use prices for 2025 (*AEO2005*, GII, and SEER), SEER shows the highest end-use-to-wellhead margins for the electric power sector, and the *AEO2005* reference case shows the lowest end-use-to-wellhead margins for the industrial sector. For the residential and commercial sectors, the projected margins in the *AEO2005* reference case fall between GII on the low end and SEER on the high end of the available forecasts. Industrial sector margins are notably lower in the *AEO2005* reference case than in the other forecasts, and electric power sector margins are notably lower in the GII forecast (where some of the differences may reflect definitional variations) than in the other forecasts.

Petroleum

The *AEO2005* projections for petroleum can be compared with forecasts from DB, GII, EVA, and PIRA. The basis of comparison varies, depending on the coverage of the other forecasts. The *AEO2005* projections for petroleum product demand, domestic production of crude oil and natural gas liquids, and imports of crude oil and petroleum products through 2025 are compared with the DB and GII forecasts in Table 37, which also shows comparisons with the EVA forecast for total U.S. imports of crude oil and petroleum products through 2025 and with the PIRA forecast through 2015.

Consistent with expected economic growth, rising demand for petroleum products is a feature of all the forecasts. DB, GII, and the *AEO2005* reference case expect total product demand in 2025 to be about 40 percent higher than in 2003. DB and GII, however, project a different slate of products. Both expect gasoline and distillate demand in 2025 that is several hundred thousand barrels per day below the *AEO2005* reference case levels. GII's projected distillate demand is 710,000 barrels per day lower in 2025 than the *AEO2005* reference case, and gasoline demand is 410,000 barrels per day lower in 2025 than the *AEO2005* reference case.

GII's forecast assumes that light and heavy vehicles will travel fewer miles in 2025 than assumed in the *AEO2005* reference case. Light vehicles use primarily gasoline, and heavy vehicles use primarily distillate. For air travel, GII assumes stronger growth than *AEO2005*, and the GII projection of jet fuel demand is 460,000 barrels per day higher than the *AEO2005* reference case in 2025. GII projects that "other" petroleum product demand will be about 730,000 barrels per day higher than shown in the *AEO2005* reference case in 2025, due mostly to higher industrial consumption of petroleum. DB's jet fuel projection for 2025 is slightly below the *AEO2005* reference case, but its "other" petroleum product projection is 880,000 barrels per day higher.

PIRA's forecast is the only one that envisions a reversal of gasoline demand growth in the future. In 2015, PIRA projects gasoline demand that is 380,000 barrels per day lower than its projection for 2010. The PIRA projections of gasoline demand and total petroleum product demand in 2015 are the lowest of all the forecasts, at 1.89 and 1.55 million barrels per day below the respective *AEO2005* reference case projections. Diesel displaces gasoline between 2010 and 2015 in PIRA's forecast, which also assumes somewhat less highway travel than does the *AEO2005* reference case. Jet fuel demand in 2015 is slightly higher in the PIRA forecast, and "other" petroleum product demand is 820,000 barrels per day higher than projected in the *AEO2005* reference case.

In all the forecasts, imports are needed to meet more than one-half of U.S. petroleum demand, and the import share of total demand is projected to increase. In 2003, 56 percent of demand was met by imports, and that share is projected to rise to 68 percent in 2025 in *AEO2005*. DB is less optimistic about domestic oil and gas production. In 2025, DB projects that crude oil production will be 710,000 barrels per day lower and natural gas liquids 760,000 barrels per day lower than projected in the *AEO2005* reference case. With DB's total petroleum demand projection about the same as that in the *AEO2005* reference case, the fraction of demand projected to be met by imports in 2025 is more than 6 percentage points above the *AEO2005* reference case projection.

GII is somewhat more optimistic about domestic crude oil and natural gas liquids production in 2025 than the *AEO2005* reference case. In 2025, GII projects that total crude oil production will be 90,000 barrels per day higher and natural gas liquids production 320,000 barrels per day higher than projected in the *AEO2005* reference case. GII is less optimistic than the *AEO2005* reference case, however, about domestic refinery expansion. Crude oil imports are 3.76 million barrels per day lower in 2025 in the GII forecast, but petroleum product imports are 3.84 million barrels per day higher than in the *AEO2005* reference case. Despite somewhat lower total demand and lower crude imports, GII projects an import share that is 0.9 percentage points higher in 2025 than in the

AEO2005 reference case. The reason is that volume gains from domestic processing of imported crude are counted as domestic production. Substitution of product imports for crude imports therefore increases the import share of product supplied.

PIRA expects the lowest level of crude oil and petroleum product imports in 2015 among the forecasts compared, due in part to relatively low projections of product demand. EVA projects the highest level of crude oil and petroleum product imports among all the forecasts, 2.18 million barrels per day above the *AEO2005* reference case in 2025.

Coal

There is a great deal of uncertainty about the possible enactment of environmental regulations that would affect coal demand in the United States. Various programs that would restrict emissions of mercury, fine particulates ($PM_{2.5}$) and greenhouse gases are being discussed and introduced by the U.S. Environmental Protection Agency and the U.S. Congress. The *AEO2005* reference case does not anticipate when and how new environmental requirements may take effect, whereas the other forecasts may include such assumptions. All the coal forecasts included in Table 38 incorporate the current requirements of the Clean Air Act Amendments of 1990 and the NO_x SIP call that affects 19 eastern and midwestern States over the forecast period. EVA assumes that legislation similar to the Clean Air Interstate Rule and the Clean Air Mercury Rule will be enacted and will include further restrictions on emissions of SO_2, NO_x, and mercury. EVA's forecast also includes a $5 per ton fee on carbon dioxide emissions beginning in 2013. The *AEO2005*, Hill, and GII forecasts do not include mandated reductions in mercury or carbon dioxide emissions.

Table 37. Comparison of petroleum forecasts, 2015 and 2025 (million barrels per day, except where noted)

Projection	2003	AEO2005			Other forecasts			
		Reference	Low world oil price	High world oil price	GII	DB	EVA	PIRA
				2015				
Crude oil and NGL production	7.41	7.46	7.32	7.83	7.41	6.51	NA	NA
Crude oil	5.69	5.49	5.37	5.81	5.17	4.91	NA	5.05
Natural gas liquids	1.72	1.96	1.95	2.02	2.24	1.61	NA	NA
Total net imports	11.24	15.40	16.19	14.10	15.18	16.17	17.70	14.68
Crude oil	9.65	13.28	13.73	12.74	11.07	NA	NA	NA
Petroleum products	1.58	2.12	2.45	1.36	4.11	NA	NA	NA
Petroleum demand	20.00	24.67	25.25	23.95	24.19	24.34	NA	23.12
Motor gasoline	8.93	11.17	11.38	10.76	10.98	10.86	NA	9.28
Jet fuel	1.57	2.15	2.16	2.13	2.23	1.96	NA	2.20
Distillate fuel	3.95	5.07	5.25	4.95	4.62	4.79	NA	4.72
Residual fuel	0.77	0.85	0.96	0.79	0.63	0.87	NA	0.68
Other	4.77	5.42	5.50	5.32	3.42	5.85	NA	6.24
Import share of product supplied (percent)	56.2	62.4	64.1	58.9	64.3	66.5	NA	64.0
				2025				
Crude oil and NGL production	7.41	6.77	6.45	7.30	7.19	5.30	NA	NA
Crude oil	5.69	4.73	4.46	5.18	4.82	4.02	NA	NA
Natural gas liquids	1.72	2.04	1.99	2.12	2.36	1.28	NA	NA
Total net imports	11.24	19.11	21.19	16.48	19.19	20.83	21.29	NA
Crude oil	9.65	16.11	16.63	14.83	12.35	NA	NA	NA
Petroleum products	1.58	3.00	4.55	1.65	6.84	NA	NA	NA
Petroleum demand	20.00	27.93	29.55	26.85	27.71	27.92	NA	NA
Motor gasoline	8.93	12.89	13.37	12.33	12.48	12.30	NA	NA
Jet fuel	1.57	2.36	2.46	2.34	2.82	2.30	NA	NA
Distillate fuel	3.95	5.81	6.68	5.63	5.10	5.51	NA	NA
Residual fuel	0.77	0.88	1.03	0.79	0.60	0.96	NA	NA
Other	4.77	5.98	6.01	5.76	6.71	6.86	NA	NA
Import share of product supplied (percent)	56.2	68.4	71.7	63.1	69.3	74.6	NA	NA

NA = Not available.

Sources: ***AEO2005:*** AEO2005 National Energy Modeling System, runs AEO2005.D102004A (reference case), LW2005.D102004A (low world oil price case), and HW2005.D102004A (high world oil price case). **GII:** Global Insight, Inc., *U.S. Energy Outlook* (Summer 2004). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski, November 11, 2004. **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **PIRA:** PIRA Energy Group (October 2004).

Table 38. Comparison of coal forecasts, 2015, 2020, and 2025 (million short tons, except where noted)

Projection	2003	AEO2005			Other forecasts		
		Reference	Low economic growth	High economic growth	EVA	Hill	GII
				2015			
Production	1,083	1,270	1,249	1,294	1,150	1,239[a]	1,189
Consumption by sector							
Electricity generation	1,004	1,185	1,166	1,208	1,082	1,173	1,100
Coking plants	24	18	17	18	21	23	20
Industrial/other	62	71	69	72	60	62	68
Total	1,095	1,273	1,252	1,297	1,163	1,258	1,188
Net coal exports	18.0	-2.8	-2.8	-2.8	-20.6	-19.0	-1.6
Exports	43.0	34.9	34.9	34.9	24.7	25.0	29.1
Imports	25.0	37.7	37.7	37.7	45.3	44.0	30.7
Minemouth price							
(2003 dollars per short ton)	17.93	16.89	16.62	17.10	19.35[b]	17.28[c,d]	NA
(2003 dollars per million Btu)	0.86	0.84	0.83	0.85	0.94[b]	0.84[c,d]	NA
Average delivered price to electricity generators							
(2003 dollars per short ton)	25.86	24.42	24.07	24.76	27.26[b]	26.89[d]	24.62[e]
(2003 dollars per million Btu)	1.28	1.23	1.22	1.25	1.36[b]	1.31[d]	1.19
				2020			
Production	1,083	1,345	1,295	1,397	1,231	1,285[a]	1,287
Consumption by sector							
Electricity generation	1,004	1,267	1,219	1,317	1,174	1,233	1,204
Coking plants	24	15	15	15	20	22	18
Industrial/other	62	71	69	73	58	59	68
Total	1,095	1,352	1,303	1,405	1,252	1,314	1,290
Net coal exports	18.0	-6.6	-6.6	-7.2	-28.3	-29.0	-6.0
Exports	43.0	35.2	35.2	34.5	26.0	22.0	25.8
Imports	25.0	41.7	41.7	41.7	54.3	51.0	31.8
Minemouth price							
(2003 dollars per short ton)	17.93	17.25	16.79	17.89	19.38[b]	17.85[c,d]	NA
(2003 dollars per million Btu)	0.86	0.86	0.83	0.89	0.95[b]	0.87[c,d]	NA
Average delivered price to electricity generators							
(2003 dollars per short ton)	25.86	24.66	24.00	25.41	27.46[b]	28.14[d]	23.70[e]
(2003 dollars per million Btu)	1.28	1.25	1.21	1.28	1.38[b]	1.37[d]	1.15
				2025			
Production	1,083	1,488	1,373	1,597	1,328	NA	1,365
Consumption by sector							
Electricity generation	1,004	1,425	1,312	1,531	1,284	NA	1,288
Coking plants	24	13	13	13	18	NA	16
Industrial/other	62	71	68	73	55	NA	68
Total	1,095	1,508	1,393	1,617	1,357	NA	1,372
Net coal exports	18.0	-19.6	-18.8	-19.6	-36.9	NA	-9.2
Exports	43.0	26.1	26.9	26.1	27.4	NA	23.7
Imports	25.0	45.7	45.7	45.7	64.3	NA	32.9
Minemouth price							
(2003 dollars per short ton)	17.93	18.26	17.11	19.78	19.60[b]	NA	NA
(2003 dollars per million Btu)	0.86	0.91	0.85	0.98	0.97[b]	NA	NA
Average delivered price to electricity generators							
(2003 dollars per short ton)	25.86	25.95	24.46	27.76	27.75[b]	NA	22.85[e]
(2003 dollars per million Btu)	1.28	1.31	1.24	1.39	1.39[b]	NA	1.10

[a]Coal production in the Hill & Associates forecast was estimated as total coal consumption minus imports plus exports.
[b]The average coal price is a weighted average of the projected spot market FOB mine price for all domestic coal.
[c]The minemouth price represents an average for domestic steam coal only. Exports and coking coal are not included in the average.
[d]The prices provided by Hill & Associates were converted from 2004 dollars to 2003 dollars in order to be consistent with *AEO2005*.
[e]Estimated by multiplying the delivered price of coal in dollars per million Btu by the average heat content of coal delivered to electricity generators in million Btu per short ton.

Btu = British thermal unit. NA = Not available.

Sources: ***AEO2005***: AEO2005 National Energy Modeling System, runs AEO2005.D102004A (reference case), LM2005.D102004A (low economic growth case), and HM2005.D102004A (high economic growth case). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2004). **Hill:** Hill & Associates, Inc., *The Outlook for U.S. Steam Coal: Long-Term Forecast to 2022* (August 2004). **GII:** Global Insight, Inc., *U.S. Energy Outlook* (Summer 2004). **PIRA:** PIRA Energy Group (October 2004).

Given the more restrictive assumptions of the EVA forecast, it is not surprising that the *AEO2005* reference case and Hill forecasts project significantly higher levels of coal consumption than EVA. While GII projects total coal consumption levels that are the most similar to EVA's in 2025, its projection of industrial consumption over the forecast is similar to that in *AEO2005*. The *AEO2005* reference case projects higher coal consumption levels than Hill (by about 3 percent in 2020) and EVA (by about 10 percent in 2025). All four forecasts show significant increases in coal consumption over the forecast period.

Both *AEO2005* and Hill project a decline in real minemouth coal prices from 2003 to 2015 but expect growth in real prices thereafter. EVA forecasts an 8-percent price increase (based on short tons) between 2003 and 2015 and an additional small increase between 2015 and 2025. The EVA forecast includes lower coal consumption and higher minemouth coal prices over all periods than either the *AEO2005* reference case or the Hill forecast.

As western coal production makes further inroads into markets traditionally served by eastern coal, the average heat content of the coals produced and consumed will drop as well, reflecting the lower thermal content per ton of western coals. The *AEO2005* reference case and EVA forecasts indicate similar average heat content (calculated by dividing dollars per ton by dollars per million Btu). The average heat content of coal production in the *AEO2005* reference case, EVA, and Hill forecasts is roughly 20.1 to 20.6 million Btu per ton in 2015, 2020, and 2025, compared with the 2003 base level of 20.9 million Btu per ton. The forecast similarities suggest that comparable shares of western production are included in the three projections.

Gross exports of coal represent a small and declining part of domestic coal production. In the *AEO2005* reference case, the share of total production that is exported is projected to fall from 4 percent in 2003 to roughly 2 percent in 2025. Currently, coal is the only domestic energy resource for which exports still exceed imports. All the forecasts project that the United States eventually will import more coal than it exports. GII projects the lowest level of coal imports, only 8 million tons more in 2025 than in 2003. Both EVA and Hill project a faster rate of increase in net coal imports, with 19 to 21 million tons more coal imported than exported in 2015. EVA projects net coal imports in 2025 equal to almost twice the tonnage projected in the *AEO2005* reference case (37 million and 20 million tons, respectively). Strong price competition from other exporters and the loss of markets as Europe moves away from coal for environmental reasons are among the causes for the long-term decline in U.S. exports. The coal forecasts reflect the uncertainties facing the U.S. coal industry as it simultaneously adapts to pressures arising from increasing regulatory restrictions on coal production, domestic and international environmental regulations, restructuring of the U.S. electricity generation industry, and increasing competition from the relatively undeveloped coalfields of international competitors.

List of Acronyms

AD	Associated-dissolved (natural gas)
AEO2004	*Annual Energy Outlook 2004*
AEO2005	*Annual Energy Outlook 2005*
Altos	Altos Partners
AMT	Alternative Minimum Tax
ANWR	Arctic National Wildlife Refuge
Btu	British thermal unit
CAFE	Corporate average fuel economy
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CBECS	Commercial Buildings Energy Consumption Survey (EIA)
CBO	Congressional Budget Office
CCCC	Climate Change Credit Corporation
CH_4	Methane
CHP	Combined heat and power
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DB	Deutsche Bank, A.G.
E85	Fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
ETBE	Ethyl tertiary butyl ether
EVA	Energy Ventures Analysis, Incorporated
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FSU	Former Soviet Union
GDP	Gross domestic product
GII	Global Insight, Incorporated
GTL	Gas-to-liquids
HAPs	Hazardous air pollutants
Hill	Hill & Associates
IRAC	U.S. average refiner's acquisition cost of imported crude oil
ITC	Investment Tax Credit
LFG	Landfill gas
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MACT	Maximum Achievable Control Technology
mpg	Miles per gallon
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
N_2O	Nitrous oxide
NA	Nonassociated (natural gas)
NAAQS	1997 National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NBP	NO_x budget program (Connecticut)
NEMS	National Energy Modeling System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NHTSA	National Highway Traffic Safety Administration
NO_x	Nitrogen oxides
NPR-A	National Petroleum Reserve-Alaska
NRC	U.S. Nuclear Regulatory Commission
NRLM	Nonroad locomotive and marine diesel fuel
NYMEX	New York Mercantile Exchange
OEF	Oxford Economic Forecasting
OMB	Office of Management and Budget
OPEC	Organization of Petroleum Exporting Countries
pCAIR	Proposed Clean Air Interstate Rule
PECO	Pennsylvania Electric Company
PEL	Petroleum Economics, Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
PM	Particulate matter
ppm	Parts per million
PTC	Renewable energy production tax credit
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Solar photovoltaics
RFG	Reformulated gasoline
RPS	Renewable portfolio standard
SAGE	System for Analysis of Global Energy Markets (EIA)
SCR	Selective catalytic reduction
SEER	Seasonal energy efficiency ratio
SEER	Strategic Energy & Economic Research, Incorporated
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SUV	Sport utility vehicle
TVA	Tennessee Valley Authority
ULSD	Ultra-low-sulfur diesel fuel
VEETC	Volumetric Ethanol Excise Tax Credit
WTI	West Texas Intermediate crude oil

Notes and Sources

Text Notes

Overview

[1] The projections in *AEO2005* are based on Federal and State laws and regulations in effect on October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections.

Legislation and Regulations

[2] The SEER is a measure of cooling performance that is used to rate the efficiency of central air conditioners and heat pumps. It is defined as the ratio of cooling output (in Btu) to total electric energy input (in watthours) during normal annual usage.

[3] National Resources Defense Council v. Abraham, U.S. Court of Appeals, 2nd District.

[4] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters," 40 CFR Part 63 (February 26, 2004), web site www.epa.gov/ttn/atw/boiler/ria-final.pdf.

[5] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Industrial Boilers and Process Heaters NESHAP*, EPA-452/R-04-002 (Washington, DC, February 2004), web site www.epa.gov/ttn/atw/boiler/ria-final.pdf.

[6] U.S. Environmental Protection Agency, "Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel: Final Rule," 40 CFR Parts 9, 69, et al. (May 11, 2004).

[7] Tier 4 refers to the fourth set of emissions standards applying to nonroad diesel emissions. The standards do not apply to locomotive and marine applications, which are covered by separate EPA regulations.

[8] U.S. Environmental Protection Agency, "Control of Emissions of Air Pollution From New Locomotive Engines and New Marine Compression Ignition Engines Less Than 30 Liters per Cylinder: Proposed Rule," 40 CFR Parts 92 and 94 (June 29, 2004).

[9] U.S. Environmental Protection Agency, *Clean Air Nonroad Diesel Summary*, EPA-420-F-04-029 (Washington, DC, May 2004), web site www. epa.gov/otaq/regs/nonroad/equip-hd/2004fr/420f04029.htm.

[10] The EPA has designated seven regional Credit Trading Areas (CTAs) in the United States, organized along State lines. See web site www.npradc.org/issues/fuels/pdf/diesel_summary.pdf.

[11] Transmix is the mixture in a pipeline at the interface between adjoining batches of petroleum product with dissimilar physical characteristics, which cannot be absorbed into adjoining batches.

[12] U.S. Environmental Protection Agency, *Clean Air Nonroad Diesel Rule Facts and Figures*, EPA-420-F-04-037 (Washington, DC, May 2004), web site www.epa.gov/nonroad-diesel/2004fr/420f04037.htm.

[13] This section describes the bill known as PL 108-357 (H.R. 4520), "American Jobs Creation Act of 2004." For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid= f:h4520enr.txt.pdf.

[14] Carry-back refers to the practice of using a credit from taxable income for a prior tax period. Carry-forward refers to using a credit in a future taxable period.

[15] The reference price for a taxable year is the price in the calendar year preceding the claendar year in which the taxable year begins. This price is determined as: (a) in the case of qualified crude oil production, the Secretary of the Treasury's estimate of the average annual wellhead price per barrel for all domestic crude oil (the price of which is not subject to regulation by the United States), and (b) in the case of qualified natural gas production, the Secretary of the Treasury's estimate of the average annual wellhead price per 1,000 cubic feet for all domestic natural gas.

[16] Extension of the in-service date for wind, closed-loop biomass, and poultry litter through 2005 was also part of the Working Families Tax Relief Act of 2004.

[17] Transmix is the mixture in a pipeline at the interface between adjoining batches of petroleum product with dissimilar physical characteristics, which cannot be absorbed into adjoining batches.

[18] This section describes the bill known as P.L. 108-311 (H.R. 1308), "Working Families Tax Relief Act of 2004." For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_public_ laws&docid=f:publ311.108.pdf.

[19] This section describes the bill known as P.L. 108-324 (H.R. 4837), "Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005." For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_ cong_public_laws&docid=f:publ324.108.pdf.

[20] Connecticut Department of Environmental Protection, "Regulations of Connecticut State Agencies (RCSA)," Title 22a, Section 22a-174-1 to 22a-174-200, "Abatement of Air Pollution," web site www.dep.state.ct.us/air2/regs/mainregs.htm.

[21] State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), "Comparison of State Multi-Pollutant Strategies for Power Plants" (April 2003).

[22] Northeast States for Coordinated Air Use Management, "Mercury Emissions from Coal-Fired Power Plants —The Case for Regulatory Action" (October 2003), web site www.nescaum.org.

[23] State of Maine, "An Act to Provide Leadership in Addressing the Threat of Climate Change," Chapter 237, H.P. 622—L.D. 845, Session Laws of the State of Maine, 121st Legislature (Approved May 21, 2003), web site http://janus. state.me.us/legis.

[24] Maine Greenhouse Gas Initiative, web site http://maineghg.raabassociates.org.

[25] Massachusetts Department of Environmental Protection, "Regulations and Notices," web site www.mass.gov/dep/bwp/daqc/daqcpubs.htm#regs.

[26] Massachusetts Department of Environmental Protection, "Emission Control Plans," web site www.mass.gov/dep/bwp/daqc/daqcpubs.htm#ecp.

[27] Web site www.mass.gov/ocd/climate.html.

[28] Massachusetts Department of Environmental Protection, web sites www.mass.gov/dep/bwp/hgres.htm and www.mass.gov/dep/bwp/daqc/daqcpubs.htm#regs.

[29] "Air Quality Standards, Definitions, Sampling and Reference Methods and Air Pollution Control Regulations for the Entire State of Missouri," Chapter 6, web site www.sos.mo.gov/adrules/csr/current/10csr/10csr.asp.

[30] State of New Hampshire, New Hampshire Code of Administrative Rules, "Multiple Pollutant and Annual Budget Trading and Banking Program," Chapter Env-A2900, web site www.des.state.nh.us/rules/air.htm.

[31] B.G. Rabe, "Greenhouse and Statehouse: The Evolving State Government Role in Climate Change" (Pew Center on Global Climate Change, November 2002), web site www.pewclimate.org.

[32] State of New York, Department of Environmental Conservation, "Acid Deposition Reduction Budget Trading Programs," web site www.dec.state.ny.us/website/dar/adopted.html.

[33] State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), "Comparison of State Multi-Pollutant Strategies for Power Plants" (April 2003).

[34] North Carolina Department of Environment and Natural Resources, *Implementation of the "Clean Smokestacks Act"* (May 30, 2003), web site http://daq.state.nc.us/news/leg/.

[35] North Carolina Department of Environment and Natural Resources, *Mercury Clean Smokestacks Act Second Interim Report* (September 2004), web site http://daq.state.nc.us/news/leg/.

[36] North Carolina Department of Environment and Natural Resources, *CO_2 Clean Smokestacks Act, Second Interim Report* (September 2004), web site http://daq.state.nc.us/news/leg/.

[37] North Carolina Department of Environment and Natural Resources, web site http://daq.state.nc.us/news/leg/.

[38] State of Oregon, Oregon Administrative Rules, Chapter 345, Division 24, "Specific Standards for Siting Non-Nuclear Facilities and Related or Supporting Facilities," web site http://arcweb.sos.state.or.us/banners/rules.htm.

[39] Energy Information Administration, "State Electricity Profiles for Oregon, 2002," web site www.eia.doe.gov/emeu/states/main_or.html.

[40] S. Sadler, "Oregon Carbon Dioxide Emission Standards for New Energy Facilities," Oregon Office of Energy, Oregon Energy Facility Siting Council, Rule Division 24, OAR 345-024-0500 (1997), web sites www.energy.state.or.us and www.climatetrust.org.

[41] Assuming a plant heat rate of 10,000 Btu per kilowatthour and a CO_2 emission factor of 25.50 kg carbon per million Btu.

[42] Texas Natural Resource Conservation Commission, web site www.tnrcc.state.tx.us/permitting/airperm/grandfathered.

[43] Web sites http://www1.leg.wa.gov/legislature and www.efsec.wa.gov.

[44] On December 7, 2004, the Alliance of Automobile Manufacturers and several California auto dealerships filed suit in the U.S. District Court in Fresno, California, against A.B. 1493.

[45] Conversion methodology assumes 70.22 kilograms of carbon dioxide per million Btu of gasoline and 125,000 Btu per gallon of gasoline, which equates to 8.78 kilograms of carbon dioxide per gallon of gasoline.

[46] The Clean Air Act allows States to opt out of Federal light-duty vehicle exhaust emissions standard requirements if they choose to adopt California's standards. Connecticut, New Jersey, and Rhode Island have also passed legislation adopting California's light vehicle emissions standards, excluding the new greenhouse gas emission standards. The California Low Emission Vehicle Program (LEVP) requires more stringent criteria emission standards and minimum sales requirements for zero-emission vehicles, which include hybrid, electric, and fuel cell vehicles. Because these States were not expected to adopt the California light vehicle greenhouse gas emission standards, the associated light vehicle fuel economy impact from the sales of zero-emission vehicles due to their opting into the California LEVP are not represented in the *AEO2005* reference case and, therefore, were not included in the A.B. 1493 sensitivity cases.

[47] California Environmental Protection Agency Air Resources Board, *Addendum Presenting And Describing Revisions To: Initial Statement of Reasons For Proposed Rulemaking, Public Hearing To Consider Adoption of Regulations To Control Greenhouse Gas Emissions From Motor Vehicles* (September 10, 2004), p. 1, web site www.arb.ca.gov/regact/grnhsgas/addendum.pdf.

[48] California Environmental Protection Agency Air Resources Board, *Addendum Presenting And Describing Revisions To: Initial Statement of Reasons For Proposed Rulemaking, Public Hearing To Consider Adoption of Regulations To Control Greenhouse Gas Emissions From Motor Vehicles* (September 10, 2004), Table 8.2-1, p. 17, web site www.arb.ca.gov/regact/grnhsgas/addendum.pdf.

[49] Percentages derived from EMFAC model runs (April 23, 2002) provided by Jonathan Taylor, California Air Resources Board (December 20, 2004).

[50] The NEMS model does not capture State-specific sales, stocks, or vehicle miles traveled. The impact of the fuel economy equivalent standards were modeled nationally and applied regionally in subsequent runs based on State-specific distributions of light vehicle energy use and travel.

[51] Analysis of the National Highway Traffic Safety Administration model year 2001 CAFE data indicated that 12.3 percent of new light trucks sold (trucks less than 8,500 pounds gross vehicle weight) have a loaded vehicle weight less than 3,750 pounds.

[52] The EMFAC model was used to develop the baseline CO_2 equivalent emissions in the CARB analysis. Reductions were estimated on the basis of a NESCCAF model and applied to the EMFAC baseline.

[53] Census Division 9 includes the following States: Alaska, California, Hawaii, Oregon, and Washington.

[54] Census Division 1 includes the following States: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Census Division 2 includes the following States: New Jersey, New York, and Pennsylvania.

[55] Energy Information Administration, *Analysis of S. 1844, the Clear Skies Act of 2003; S. 843, the Clean Air Planning Act of 2003; and S. 366, the Clean Power Act of 2003*, SR/OIAF/2004-05 (Washington, DC, May 2005),

web site www.eia. doe.gov/oiaf/servicerpt/csa/pdf/sroiaf (2004)05.pdf.

[56] U.S. Environmental Protection Agency, "Interstate Air Quality Rule," web site www.epa.gov/interstateair quality.

[57] *Federal Register*, Vol. 69, No. 20, 40 CFR parts 51, 72, 75, and 96 (January 30, 2004).

[58] *Federal Register*, Vol. 69, No. 112, 40 CFR Parts 51, 72, 73, 74, 77, 78, and 96 (June 10, 2004).

[59] U.S. Environmental Protection Agency, "Utility Mercury Reductions Rule," web site www.epa.gov/air/mercuryrule.

[60] *Federal Register*, Vol. 69, No. 20, 40 CFR Parts 60 and 63 (January 30, 2004).

[61] *Federal Register*, Vol. 69, No. 51, 40 CFR Parts 60, 72, and 75 (March 16, 2004).

[62] Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003), Table 8.2a, p. 224.

[63] The bill covers emissions of the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (NO_x), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

[64] This section describes the provisions proposed in S.A. 3546 and H.R. 4067, both titled the Climate Stewardship Act of 2004. For the full text of the bill, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills& docid=f:h4067ih.txt.pdf.

[65] The commercial sector includes government entities.

[66] In the definition of a covered entity, the clarification that the 10,000 metric ton threshold applies to emissions "from any single facility owned by the entity" was not present in the original version of the bill (S. 139). Because few commercial facilities would have emissions above the threshold, most entities in the commercial sector would be exempt. Addition of the "single facility" restriction clears up a key uncertainty in the definition of a "covered entity" in S. 139. The most recent bill also requires that all of a covered entity's emissions be subject to allowance requirements—not just the emissions from facilities that exceed the threshold. This interpretation suggests a possible avoidance strategy: an entity might design, organize, and operate its facilities to ensure that no single facility's emissions exceeded the threshold.

[67] The bill allows each covered entity to obtain 15 percent of its emission allowances from alternative compliance sources, including purchase of allowances from certified reduction or sequestration programs, both domestically and abroad. As an incentive for early action, entities reducing their emissions below 1990 levels by 2010 may be granted a limit of 20 percent of their target reductions from alternative compliance sources from 2010 to 2016.

[68] Covered entities would be required to submit allowances for their covered emissions or, to a limited extent, offsetting emission reduction credits from noncovered entities. Therefore, the covered emissions, less any offset credits, would be subject to the allowance cap.

[69] This provision would require the entity to show that a specific capital project is underway to reduce emissions and to return any allowances borrowed, at an effective interest rate of 10 percent per year. In addition, borrowed allowances would count against the limit on alternative compliance offsets. Therefore, in the aggregate, allowance borrowing would likely be minimal.

[70] The emissions for 2000 cited in the bill match the levels reported in U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000*, EPA-430-R-02-003 (Washington, DC, April 2002), after adjusting for the residential and agricultural sectors and U.S. territories.

[71] Energy Information Administration, *Analysis of S. 139, the Climate Stewardship Act of 2003*, SR/OIAF/2003-02 (Washington, DC, June 2003). For the full report, see web site www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf. For a summary, see web site www.eia.doe.gov/oiaf/servicerpt/ml/pdf/summary.pdf. A followup analysis of the amended (single phase) version of the bill, *Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003*, is available at web site www.eia.doe.gov/oiaf/analysispaper/sacsa/index.html.

[72] A provision entitled "Dedicated Program for Sequestration in Agricultural Soils" would allow an entity to satisfy up to 1.5 percent of its total allowance submission requirements with registered increases in net carbon sequestration in agricultural soils. Entities would remain subject to an overall limit on offsets of 15 percent, or 20 percent if they met certain early action criteria.

[73] Refineries, as industrial entities, would be required to obtain allowance permits for the fuel they burned in refining oil, in addition to allowances for downstream emissions of the transportation fuel they sold. The costs would be passed on to consumers.

Issues in Focus

[74] For a description of the SAGE model, see Energy Information Administration, *International Energy Outlook 2004*, DOE/EIA-0484(2004) (Washington, DC, April 2004).

[75] For a detailed review of real GDP and oil projections by country and region, see *International Energy Outlook 2004*.

[76] A more rigorous determination of income elasticities, which controlled for price changes, was also undertaken. It involved a statistical estimation of the relationship between the projected demand for oil and projected real GDP and world oil prices. The numbers quoted here for income elasticities are similar to those that were statistically estimated.

[77] For a recent study and a review of the empirical literature see D. Gately and H.G. Huntington, "The Asymmetric Effects of Changes in Price and Income on Energy and Oil Demand," OP50, Energy Modeling Forum (Stanford, CA: Stanford University, August 2001).

[78] D. Gately and H.G. Huntington, "The Asymmetric Effects of Changes in Price and Income on Energy and Oil Demand," OP50, Energy Modeling Forum (Stanford, CA: Stanford University, August 2001).

[79] Cumulative production in a year is obtained by multiplying oil production per day by 365. For oil-producing countries, it is assumed that oil is sold domestically at the same world oil price.

[80] G.A. Smook, *Handbook for Pulp and Paper Technologies*, 2nd Edition (Bellingham, WA: Angus Wilde Publications, 1992).

[81] American Forest and Paper Association, *Statistics of Paper, Paperboard and Wood Pulp*, 41st Edition (Washington, DC, 2004).

[82] American Forest and Paper Association, *Statistics of Paper, Paperboard and Wood Pulp*, 41st Edition (Washington, DC, 2004).

[83] Note that the output forecasts were disaggregated into the four components of bulk chemicals in previous *AEOs*. The history and prospects for agricultural chemicals were discussed in *Annual Energy Outlook 2004*.

[84] American Chemical Council, *Guide to the Business of Chemistry 2003*, p. 169.

[85] For example, PotashCorp, "The PotashCorp Letter" (June 2003).

[86] For example, see Celanese AG, "Celanese To Source Methanol from Southern Chemical Company" (press release, July 22, 2003).

[87] National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2004).

[88] National Highway Traffic Safety Administration, *Automotive Fuel Economy Program Annual Update Calendar Year 2002* (Washington, DC, September 2003), Table II-4.

[89] U.S. Environmental Protection Agency, *Light-Duty Automotive Technology and Fuel Economy Trends: 1975 Through 2004* (Ann Arbor, MI, April 2004), Table E-3.

[90] S.C. Davis and S.W. Diegel, *Transportation Energy Data Book Edition 24*, ORNL-6970 (Oak Ridge, TN: Oak Ridge National Laboratory, October 2003), Table 4.9.

[91] "President Announces Clear Skies & Global Climate Change Initiatives" (February 14, 2002), web site www.whitehouse.gov/news/releases/2002/02/20020214-5.html.

[92] See the Addendum to the *Global Climate Change Policy Book*, web site www.whitehouse.gov/news/releases/2002/02/climatechange.html. The BAU projections cited in the Addendum are somewhat higher than those in a Policies and Measures case developed by the EPA for the *U.S. Climate Action Report 2002*. EIA has adjusted the Addendum projections to reflect the most recent (2002 and 2003) data on emissions published by EIA, as well as to estimate the intervening years of the projections (the EPA projections were provided for 5-year intervals). In addition, EIA has extrapolated the projections to estimate emissions for 2025.

[93] U.S. Department of State, *U.S. Climate Action Report 2002* (Washington, DC, May 2002), Chapter 5, "Projected Greenhouse Gas Emissions," pp. 70-80, web site http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsUSClimateActionReport.html.

[94] U.S. Environmental Protection Agency, *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions*, EPA 30-R-99-013 (Washington, DC, September 1999), web site www.epa.gov/ghginfo/pdfs/07-complete.pdf; and *Addendum to the U.S. Methane Emissions 1990-2020: Update for Inventories, Projections, and Opportunities for Reductions* (December 2001), web site www.epa.gov/ghginfo/pdfs/final_addendum2.pdf.

[95] U.S. Environmental Protection Agency, *U.S. High GWP Gas Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions*, EPA 000-F-97-000 (Washington, DC, June 2001), web site www.epa.gov/ghginfo/pdfs/gwp_gas_emissions_6_01.pdf.

[96] U.S. Environmental Protection Agency, *U.S. Adipic Acid and Nitric Acid N_2O Emissions 1990-2020: Inventories, Projections and Opportunities for Reductions* (Washington, DC, December 2001), web site www.epa.gov/ghginfo/pdfs/adipic.pdf.

[97] A degree-day is defined as the difference between the average daily temperature (in degrees Fahrenheit) and 65. Averages above 65 degrees Fahrenheit count as cooling degree-days, and averages below 65 degrees Fahrenheit count as heating degree-days. For example, if the average temperature on a given day is 40 degrees Fahrenheit, then 25 heating degree-days are counted.

[98] The rate was later raised to 15 percent by the Crude Oil Windfall Profits Act of 1980, which extended the credit to December 31, 1985, when it was allowed to lapse for wind.

[99] Dollars are expressed in year 2003 values, except as otherwise noted.

[100]See IRS Form 8835, "Renewable Electricity Production Credit," for the year 2003, web site www.irs.gov/pub/irs-pdf/f8835.pdf.

[101]Interstate Renewable Energy Council, Database of State Incentives for Renewable Energy, web site www.dsire.org (September 22, 2003). Note: 425 megawatts, the original mandated term in 1994, has been extended to 825 megawatts in 2006 and 1,125 megawatts in 2010.

[102]"Tax Relief Extension Act of 1999," Public Law 106-170.

[103]The American Wind Energy Association estimates 1,697 megawatts of installations of all sizes in 2001 (see web site www.awea.org/faq/ instcap.html).

[104]"Job Creation and Worker Assistance Act of 2002," Public Law 107-147.

[105]The American Wind Energy Association estimates 1,689 megawatts net capacity growth in 2003 (see web site www.awea.org/faq/instcap.html).

[106]Wind power facilities also receive a 5-year accelerated depreciation allowance on Federal income tax.

[107]For further discussion of cost and performance improvements, see C. Namovicz, "Modeling Wind and Intermittent Generation in the National Energy Modeling System (NEMS)," in American Wind Energy Association, *WindPower 2003 Conference Proceedings* (2003).

[108]Cost includes "busbar" costs plus transmission interconnection charge, but does not include additional grid services that may be required to facilitate integration of wind power. Excellent wind resources refer to sites in wind power Class 6 or better, defined by the Pacific Northwest Laboratory as a site with an annual average wind speed at 50 meter hub height of 8.0 meters per second (17.9 miles per hour) or higher. See D.L. Elliot et al., *Wind Energy Resource Atlas of the United States* (Pacific Northwest Laboratory, March 1987), p. 3.

[109]Note that the levelized cost of both natural gas and coal plants depends on expected utilization rates. For comparison purposes, an 85-percent utilization rate is assumed for coal and 87 percent for combined cycle.

Effective utilization rates (capacity factors) for current-technology wind plants range from 33 to 40 percent, depending on quality of the wind resource. The 40-percent capacity factor corresponds to the lowest levelized wind cost.

[*110*]Claiming the PTC precludes these facilities from claiming the 10-percent investment tax credit also available to geothermal and solar plants. Also, the tax credit applies only to generation sold to a non-related party, and thus would not be available to facilities using photovoltaics or other "distributed generation" technology to provide on-site power.

[*111*]For example, leading Danish wind turbine manufacturer Vestas announced in early 2003 plans to build a significant factory in Oregon, but uncertainty over PTC extension was cited as the primary reason for delaying or curtailing the plan. See B. Jacklet, *Portland Tribune* (June 13, 2003), web site www.portlandtribune.com/archview.cgi?id=18698.

[*112*]The distributed generation projections for the residential and commercial sectors currently use an average electricity price in energy savings calculations without specific consideration of the time-of-day or demand-charge rates applicable to some customers. These projections focus only on baseload electricity requirements. However, potential investment decisions involving PV systems do use an "air-conditioning" electricity price in energy savings calculations, since maximum PV generation correlates with the air conditioning season.

[*113*]Distributed generation technologies are assumed to receive the grid's marginal cost of generation—the avoided cost of generation only, without transmission and distribution costs that are included in the retail rate.

[*114*]PV installed costs are per kilowatt of peak capacity and represent grid-connected systems with no battery storage or power backup. Installed costs for all other distributed generation technologies represent grid-connected CHP systems. Installed capital costs for all technologies include costs for equipment, labor and materials, interconnection, project and construction management, engineering and contingency fees.

[*115*]Electrical conversion efficiency for PV is the system efficiency as opposed to solar cell efficiency. For a more detailed description of residential and commercial distributed generation assumptions, including combined electrical and thermal efficiency for CHP systems, see *Assumptions for the Annual Energy Outlook 2005*, web site www.eia.doe.gov/oiaf/aeo/assumption/index.html.

[*116*]For PV and fuel cell technologies, a doubling of cumulative shipments results in an assumed 13-percent reduction in installed capital costs. For microturbines, a doubling results in an assumed 10-percent reduction in costs.

[*117*]ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* (January 2000), p. 17.

[*118*]Absorption chillers use heat instead of an electric motor in the compression phase of the cooling cycle. The waste heat produced during the generation process may be used with an absorption chiller to provide cooling in a CHP system.

[*119*]A discussion of the regulation issues and a database providing basic State-by-State permitting information for distributed generation projects is on the Energy and Environmental Analysis, Inc., web site at www.eea-inc.com/rrdb/DGRegProject/guide.html.

[*120*]The IEEE standard was announced in July 2003. See web site http://standards.ieee.org/announcements/1547idr.html.

[*121*]The types of pollutants responsible for designation as a nonattainment zone vary by region. A list of nonattainment areas is available at web site www.epa.gov/oar/oaqps/greenbk.

[*122*]Distributed generation projections in the buildings sectors are developed at the Census division level to include variation between geographical regions. There are nine Census divisions in the United States. For a map showing the States included in each division, see web site www.eia.doe.gov/geography.html.

[*123*]Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" (preliminary).

[*124*]Current tax law includes a 10-percent investment tax credit available to businesses that install a qualifying solar PV system. In addition, commercial PV owners may depreciate their equipment using an accelerated depreciation schedule and a 5-year economic life. The depreciable basis only needs to be reduced by half of the investment tax credit.

[*125*]See Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

[*126*]For further information on the California Energy Commission rebate program, see web site www.energy.ca.gov/renewables/emerging_renewables. html. For a discussion of State renewable energy requirements see T. Petersik, "State Renewable Energy Requirements and Goals: Status Through 2003" (July 2004), web site www.eia.doe.gov/oiaf/analysispaper/rps/index.html. For information on renewable energy incentives throughout the United States, see the North Carolina Solar Center's Database of State Incentives for Renewable Energy, web site www.dsireusa.org.

[*127*]The buildings sector technology cases assume that current equipment and building standards are met but do not include feedback effects on energy prices or economic growth.

[*128*]The high technology case assumptions call for PV costs to decline by 17 percent, fuel cell costs to decline by 29 percent, and costs for microturbines to decline by 13 percent with a doubling of cumulative shipments.

Market Trends

[*129*]Energy-intensive industries include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.

[130]The reference case assumes the Organization of Petroleum Exporting Countries' (OPEC) members will continue to demonstrate a disciplined production approach that reflects a strategy of price defense in which the larger producers are willing to increase or decrease production levels to maintain fairly stable prices (in real dollar terms) to discourage the development of alternative crude oil supplies or energy sources, allow for continued robust worldwide economic growth, and maintain compliance with quotas, particularly for smaller OPEC producers. Under this strategy, prices are assumed to be kept in a range from $27 to $30 per barrel in 2003 dollars, near the high end of the current OPEC price target range. Since OPEC, particularly the Persian Gulf nations, are expected to be the dominant supplier of oil in the international market over the mid-term, the organization's production choices will significantly affect world oil prices. The low oil price scenario could result from a future market where all oil production becomes more competitive. The high A and B price scenarios could result from a more cohesive and market-assertive OPEC with lower production goals and other non-financial (geopolitical) considerations or from the development of a less optimistic oil resource situation than currently expected.

[131]The intensities shown were disaggregated using the divisia index. The divisia index is a weighted sum of growth rates and is separated into a sectoral shift or "output" effect and an energy efficiency or "substitution" effect. It has at least two properties that make it superior to other indexes. First, it is not sensitive to where in the time period or in which direction the index is computed. Second, when the effects are separated, the individual components have the same magnitude, regardless of which is calculated first. See Energy Information Administration, "Structural Shift and Aggregate Energy Efficiency in Manufacturing" (unpublished working paper in support of the National Energy Strategy, May 1990); and Boyd et al., "Separating the Changing Effects of U.S. Manufacturing Production from Energy Efficiency Improvements," *Energy Journal*, Vol. 8, No. 2 (1987).

[132]Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence. Alternative fuels include ethanol, electricity, hydrogen, natural gas, and propane.

[133]Small light trucks (compact pickup trucks and compact vans) are used primarily as passenger vehicles, whereas medium light trucks (compact utility trucks and standard vans) and large light trucks (standard utility trucks and standard pickup trucks) are used more heavily for commercial purposes.

[134]Values for incremental investments and energy expenditure savings are discounted back to 2004 at a 7-percent real discount rate.

[135]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); J. DeCicco et al., *Technical Options for Improving the Fuel Economy of U.S. Cars and Light Trucks by 2010-2015* (Washington, DC: American Council for an Energy Efficient Economy, April 2001); M.A. Weiss et al., *On the Road in 2020: A Life-Cycle Analysis of New Automotive Technologies* (Cambridge, MA: Massachusetts Institute of Technology, October 2000); A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001); and Energy and Environmental Analysis, Inc., *Documentation of Technologies included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (prepared for Energy Information Administration, September 30, 2002).

[136]Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and combined heat and power capacity. The costs reflect the arithmetic average of the regional cost.

[137]*AEO2005* does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2002, EIA estimates that as much as 134 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2002, plus an additional 362 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See *Annual Energy Review 2003*, Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

[138]Avoided cost estimates the incremental cost of fuel and capacity displaced by a unit of the specified resource and more accurately reflects its as-dispatched energy value than comparison to the levelized cost of other individual technologies. It does not reflect system reliability cost nor does it necessarily indicate the lowest cost alternative for meeting system energy and capacity needs.

[139]Associated-dissolved natural gas is produced in conjunction with crude oil. Nonassociated gas is produced without crude oil production.

[140]Unconventional gas includes tight (low permeability), sandstone gas, shale gas, and coalbed methane.

[141]Gas exports from the United States to Mexico continue to exceed imports from Mexico through the end of the projections.

[142]Energy Information Administration, *Analysis of Oil and Gas Production in the Arctic National Wildlife Refuge*, SR/OIAF/2004-04 (Washington, DC, March 2004).

[143]**Buildings:** Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004). Industrial: EIA, *Industrial Model: Update on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001). **Transportation:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993); and A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne,

IL: Argonne National Laboratory, 2001). **Fossil-fired generating technologies:** U.S. Department of Energy, Office of Fossil Energy. **Renewable generating technologies:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997).

[*144*]U.S. Environmental Protection Agency, *Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report*, EPA-600/R-01-109, April 2002, Table ES-1, Page ES-10.

Table Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, D, and E of this report.

Table 1. Total energy supply and disposition in the *AEO2005* reference case: summary, 2002-2025: AEO-2005 National Energy Modeling System, run AEO2005.D102004A. **Notes:** Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

Table 2. Impacts of 13 SEER central air conditioner and heat pump standard compared with 12 SEER standard, 2006-2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A and SEER12.D110204A. **Note:** Future costs and savings (energy bill savings, equipment cost increase, and net present value) are discounted back to 2005 at a 7-percent real discount rate.

Table 3. Final nonroad diesel emissions standards: U.S. Environmental Protection Agency, *Clean Air Nonroad Diesel Rule, Exhaust Emission Standards*, EPA-420-F-04-032 (Washington, DC, May 2004), web site www.epa.gov/nonroad-diesel/2004fr/420f04032.htm. **Notes:** For rated engine power 25 to less than 75 horsepower, the 3.5 standard includes both NO_x and nonmethane hydrocarbons. For rated engine power 750 horsepower or more, the 5.0 standard for NO_x applies to generator sets over 1,200 horsepower. For all generator sets, the 0.02 standard for particulate matter applies to generator sets, and the 0.03 standard applies to other engines; the 0.50 standard for NO_x applies to generator sets only.

Table 4. Timeline for implementing nonroad diesel fuel sulfur limits: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Notes:** For all standards, the effective date is June 1 of the year indicated. For small refiners in 2014 and after, the NRLM diesel downgrade to 500 ppm is allowed indefinitely; the 15 ppm standard is required at the refinery gate only.

Table 5. Key projections for distillate fuel markets in two cases, 2007-2014: AEO2005 National Energy Modeling System, runs AEO2005.D102004A and AEO2005.NONONROAD.D102704A.

Table 6. Basic features of State renewable energy requirements as of December 31, 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Notes:** The Minnesota mandate specifies various dates, beginning in 2003. The original requirement for 125 megawatts of biomass capacity has been reduced. For the Minnesota goal, specific characteristics are being determined. See web site www.puc.state.mn.us, Docket 03-869. NS = not specified in the State requirement. NA = not applicable.

Table 7. Estimated capacity contributing to State renewable energy programs through 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Notes:** Biomass includes biomass co-firing and cogeneration capacity, but none is known to have been built. In Arizona, a 3-megawatt biomass-fueled plant slated for 2003 entered service in early 2004 and is not shown here. In addition to capacity shown here, the Salt River project added a 4-megawatt landfill gas project under a separate requirement. In California, new capacity that contributes to the State's RPS requirement but was built for other reasons. In Wisconsin, 20 kilowatts of solar capacity was also built. The RPS also spurred biomass co-firing in varying proportions at 79 megawatts of existing fossil-fueled capacity, as well as refurbishment and operation of 7.2 megawatts of existing hydroelectric capacity. Pennsylvania's program has resulted in 10 megawatts of new renewables capacity. In addition, 118 megawatts of new wind capacity in Pennsylvania and 66 megawatts in West Virginia were supported by separate sustainable development funds. Fewer than one-half of the States accept mass-burn municipal solid waste, and specific requirements vary by State. Totals shown in the table may not equal the sum of their components, due to independent rounding.

Table 8. Existing State air emissions legislation with potential impacts on the electricity generation sector: Sources cited in the text.

Table 9. CARB CO_2 equivalent emission standards for light-duty vehicles, model years 2009-2016: California Air Resources Board, *Staff Report: Initial Statement of Reasons for Proposed Rulemaking, Public Hearing To Consider Adoption of Regulations To Control Greenhouse Gas Emissions From Motor Vehicles* (Sacramento, CA, August 6, 2004).

Table 10. CARB fuel economy equivalent standards for light-duty vehicles, model years 2009-2016: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 11. Comparison of key factors in the CARB and EIA analyses, 2020: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 12. Emissions targets in multi-pollutant legislation: Energy Information Administration, *Analysis of S. 1844, the Clear Skies Act of 2003; S. 843, the Clean Air Planning Act of 2003; and S. 366, the Clean Power Act of 2003*, SR/OIAF/2004-05 (Washington, DC, May 2005), web site www.eia.doe.gov/oiaf/servicerpt/csa/pdf/sroiaf(2004)05.pdf. **Notes:** The limits on NO_x emissions under S. 1844 are split between two regions: 1.47 million tons in Zone 1 (the East) in 2008 to 2017 and 0.72 million tons in Zone 2 (the West) from 2008 through 2017; and 1.07 million tons in Zone 1 and 0.72 million tons in Zone 2 in 2018. The 2009 limit on SO_2 emissions under S. 366 is split between

two regions: 0.275 million tons in the West and 1.975 million tons in the other regions. Under S. 366, minimum facility-specific reductions of mercury emissions without trading are required in 2008. Under S. 843, minimum facility-specific reductions of mercury emissions between 50 percent (2009 to 2012) and 70 percent (after 2012) are required. Under S. 366, the 2009 limit on CO_2 emissions from the electricity sector is the estimated 1990 emissions level. Under S. 843, the 2009 to 2012 limit on CO_2 emissions is based on EIA's *AEO2004* projection of 2006 emissions, and the limit for 2013 and subsequent years is based on the estimated 2001 emissions level.

Table 13. Key projections from EIA's 2004 analysis of proposed multi-pollutant control bills, 2025: Energy Information Administration, AEO2004 National Energy Modeling System, runs AEO2004.D101703E, INBASE. D040904A, INCS3PWS.D040904A, INCA4P.D040904A, INCA4PLO.D040904A, and INJF4P.D041604A. **Note:** mercury emissions in 2003 are NEMS estimates, not actual amounts.

Table 14. Historical emissions and proposed future caps for the combination of affected pCAIR States: 2002: U.S. Environmental Protection Agency, web site http://cfpub.epa.gov/gdm. **Future emissions caps:** U.S. Environmental Protection Agency, web site www.epa.gov/interstateair quality/rule.html.

Table 15. Key electricity sector projections from EIA's analysis of proposed pCAIR regulations, 2015 and 2025: 2003 SO_2 allowance price: U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/auctions/2003/03summary.html. **Other 2003 values and projections:** Energy Information Administration, AEO-2005 National Energy Modeling System, runs AEO2005. D102004A and CAIR2005.D010505A. **Note:** Coal-fired capacity retrofits include currently planned and unplanned (projected) FGD and SCR installations.

Table 16. Projected growth in world gross domestic product, oil consumption, and oil intensity in the *AEO2005* reference case, 2003-2025: United States: AEO2005 National Energy Modeling System, run AEO2005.D102004A. **Other countries:** Energy Information Administration, *International Energy Outlook 2004*, DOE/EIA-0484(2004) (Washington, DC, April 2004).

Table 17. Key projections in the reference case, 2003-2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 18. Key projections in the high A world oil price case, 2003-2025: AEO2005 National Energy Modeling System, run HW2005.D102004A.

Table 19. Key projections in the high B world oil price case, 2003-2025: AEO2005 National Energy Modeling System, run VHW2005.D010705A.

Table 20. Key projections in the low world oil price case, 2003-2025: AEO2005 National Energy Modeling System, run LW2005.D102004A.

Table 21. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 22. Levelized costs of new conventional and renewable generation in two cases, 2010: AEO2005 National Energy Modeling System, runs AEO2005. D102004A and PTCEXT05.D102904A. **Notes:** Cost "at the busbar," does not include transmission investment or additional costs to accommodate intermittent renewable resources. Costs reflect national averages for best available regional resources; comparative costs within specific regions may differ significantly. Fuel costs are slightly reduced with the PTC, reflecting reduced demand from the electric power sector. It is assumed that PV will continue to take advantage of the higher-value investment tax credit (ITC) rather than the PTC. Avoided costs represent estimates of the incremental cost of fuel and capacity displaced by a unit of the specified resource and more accurately reflect their as-dispatched energy value. They do not reflect system reliability costs, nor do they necessarily indicate the lowest cost alternative for meeting system energy and capacity needs.

Table 23. Renewable electricity capacity and generation in two cases, 2005, 2015, and 2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A and PTCEXT05.D102904A.

Table 24. Projected installed costs and electrical conversion efficiencies for distributed generation technologies by year and technology, 2004, 2010, 2020, 2025: Energy Information Administration, *Assumptions to the Annual Energy Outlook 2005*, DOE/EIA-0554 (2005) (Washington, DC, February 2005), web site www.eia.doe.gov/oiaf/aeo/assumption/index.html.

Table 25. Buildings sector distributed electricity generation in alternative cases: difference from the reference case in 2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, BLDFRZN. D102104A, BLDHIGH.D110404A, LW2005.D102004A, and HW2005.D102004A.

Table 26. New car and light truck horsepower ratings and market shares, 1990-2025: History: U.S. Environmental Protection Agency, Office of Transportation and Air Quality, *Light-Duty Automotive Technology And Fuel Economy Trends: 1975-2003*, EPA-420-S-03-004, April 2003. **Projections:** AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 27. Costs of producing electricity from new plants, 2015 and 2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 28. Technically recoverable U.S. natural gas resources as of January 1, 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 29. Crude oil production from Gulf of Mexico offshore, 2003-2025: AEO2005 National Energy Modeling System, run AEO2005.D102004A.

Table 30. Technically recoverable U.S. oil resources as of January 1, 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 31. Onshore and offshore lower 48 crude oil production in three cases, 2025: AEO2005 National Energy Modeling System, runs AEO2005.D102004A, LW2005. D102004A, and HW2005.D102004A.

Figure Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, D, and E of this report.

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Appendixes

Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Production							
Crude Oil and Lease Condensate	12.15	12.03	12.75	11.63	11.03	10.01	-0.8%
Natural Gas Plant Liquids	2.56	2.34	2.66	2.67	2.80	2.81	0.8%
Dry Natural Gas	19.48	19.58	20.97	21.33	22.48	22.42	0.6%
Coal	22.70	22.66	25.10	25.56	27.04	29.90	1.3%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[1]	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other[2]	1.12	0.93	0.97	0.78	0.77	0.82	-0.5%
Total	**71.94**	**71.42**	**77.79**	**77.73**	**80.35**	**82.73**	**0.7%**
Imports							
Crude Oil[3]	19.93	21.08	24.69	28.98	32.29	35.16	2.4%
Petroleum Products[4]	4.75	5.16	6.06	6.32	6.83	8.27	2.2%
Natural Gas	4.11	4.02	5.71	8.00	8.95	9.70	4.1%
Other Imports[5]	0.56	0.69	0.92	1.07	1.15	1.23	2.6%
Total	**29.35**	**30.95**	**37.38**	**44.37**	**49.22**	**54.36**	**2.6%**
Exports							
Petroleum[6]	2.05	2.13	2.14	2.21	2.26	2.32	0.4%
Natural Gas	0.52	0.70	0.65	0.81	0.86	0.83	0.8%
Coal	1.03	1.12	1.06	0.88	0.89	0.65	-2.5%
Total	**3.60**	**3.95**	**3.86**	**3.90**	**4.01**	**3.80**	**-0.2%**
Discrepancy[7]	**-0.30**	**0.18**	**0.05**	**-0.09**	**-0.05**	**0.10**	**N/A**
Consumption							
Petroleum Products[8]	38.41	39.09	44.84	48.07	51.30	54.42	1.5%
Natural Gas	23.59	22.54	26.11	28.69	30.73	31.47	1.5%
Coal	21.98	22.71	24.95	25.71	27.27	30.48	1.3%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[1]	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Other[9]	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Net Imports - Petroleum	**22.64**	**24.10**	**28.61**	**33.10**	**36.87**	**41.11**	**2.5%**
Prices (2003 dollars per unit)							
World Oil Price (dollars per barrel)[10]	24.10	27.73	25.00	26.75	28.50	30.31	0.4%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	3.06	4.98	3.64	4.16	4.53	4.79	-0.2%
Coal Minemouth Price (dollars per ton)	18.23	17.93	17.30	16.89	17.25	18.26	0.1%
Average Electricity Price (cents per kilowatthour)	7.4	7.4	6.6	6.9	7.2	7.3	-0.1%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 natural gas wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2002 coal minemouth prices: EIA, *Annual Coal Report 2003*, DOE/EIA-0584(2003) (Washington, DC, September 2004). 2003 petroleum supply values and 2002 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002*, DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2002 and 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004).
Projections: EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Energy Consumption							
Residential							
Distillate Fuel	0.92	0.96	0.90	0.88	0.83	0.77	-1.0%
Kerosene	0.06	0.07	0.09	0.09	0.09	0.09	0.8%
Liquefied Petroleum Gas	0.57	0.54	0.57	0.61	0.64	0.67	0.9%
Petroleum Subtotal	1.54	1.58	1.56	1.58	1.56	1.53	-0.1%
Natural Gas	5.04	5.25	5.68	5.90	6.05	6.17	0.7%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	-1.0%
Renewable Energy[1]	0.39	0.40	0.40	0.39	0.39	0.38	-0.3%
Electricity	4.32	4.37	5.02	5.40	5.79	6.18	1.6%
Delivered Energy	**11.30**	**11.61**	**12.67**	**13.29**	**13.80**	**14.26**	**0.9%**
Electricity Related Losses	9.62	9.71	10.80	11.29	11.77	12.35	1.1%
Total	**20.92**	**21.31**	**23.47**	**24.58**	**25.56**	**26.62**	**1.0%**
Commercial							
Distillate Fuel	0.50	0.52	0.62	0.66	0.71	0.77	1.8%
Residual Fuel	0.08	0.07	0.07	0.07	0.08	0.08	0.2%
Kerosene	0.02	0.02	0.03	0.03	0.03	0.03	0.5%
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.11	0.11	0.5%
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.2%
Petroleum Subtotal	0.74	0.75	0.86	0.91	0.96	1.02	1.4%
Natural Gas	3.20	3.22	3.49	3.69	3.91	4.17	1.2%
Coal	0.09	0.10	0.10	0.10	0.10	0.10	-0.1%
Renewable Energy[3]	0.08	0.09	0.09	0.09	0.09	0.09	0.0%
Electricity	4.12	4.13	5.00	5.63	6.33	7.12	2.5%
Delivered Energy	**8.23**	**8.29**	**9.53**	**10.41**	**11.38**	**12.49**	**1.9%**
Electricity Related Losses	9.18	9.18	10.76	11.77	12.86	14.25	2.0%
Total	**17.40**	**17.46**	**20.29**	**22.18**	**24.24**	**26.74**	**2.0%**
Industrial[4]							
Distillate Fuel	0.99	1.03	1.04	1.08	1.14	1.19	0.7%
Liquefied Petroleum Gas	2.17	2.09	2.30	2.44	2.59	2.74	1.2%
Petrochemical Feedstock	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	0.21	0.28	0.34	0.38	0.38	0.38	1.4%
Motor Gasoline[2]	0.30	0.31	0.31	0.33	0.35	0.37	0.9%
Other Petroleum[5]	4.26	4.30	4.69	4.69	5.02	5.23	0.9%
Petroleum Subtotal	9.15	9.31	10.17	10.43	11.03	11.47	1.0%
Natural Gas	7.75	7.19	8.10	8.50	8.89	9.26	1.2%
Lease and Plant Fuel[6]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Natural Gas Subtotal	8.90	8.34	9.31	9.73	10.21	10.57	1.1%
Metallurgical Coal	0.65	0.67	0.55	0.48	0.42	0.37	-2.7%
Steam Coal	1.37	1.39	1.42	1.42	1.42	1.42	0.1%
Net Coal Coke Imports	0.06	0.05	0.06	0.05	0.05	0.05	-0.2%
Coal Subtotal	2.08	2.11	2.03	1.95	1.89	1.83	-0.6%
Renewable Energy[7]	1.78	1.79	2.07	2.19	2.34	2.50	1.5%
Electricity	3.32	3.31	3.78	3.98	4.19	4.39	1.3%
Delivered Energy	**25.23**	**24.86**	**27.35**	**28.27**	**29.66**	**30.76**	**1.0%**
Electricity Related Losses	7.38	7.35	8.13	8.31	8.52	8.78	0.8%
Total	**32.61**	**32.21**	**35.47**	**36.58**	**38.19**	**39.53**	**0.9%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Transportation							
Distillate Fuel[8]	5.42	5.54	6.95	7.67	8.35	9.05	2.3%
Jet Fuel[9]	3.34	3.26	4.04	4.45	4.74	4.89	1.9%
Motor Gasoline[2]	16.48	16.64	19.14	20.81	22.31	24.04	1.7%
Residual Fuel	0.65	0.62	0.56	0.57	0.58	0.58	-0.3%
Liquefied Petroleum Gas	0.02	0.02	0.06	0.07	0.08	0.09	6.0%
Other Petroleum[10]	0.20	0.24	0.26	0.27	0.29	0.31	1.2%
Petroleum Subtotal	26.10	26.31	31.00	33.84	36.35	38.97	1.8%
Pipeline Fuel Natural Gas	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Compressed Natural Gas	0.01	0.02	0.06	0.08	0.10	0.11	7.6%
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	6.7%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.08	0.08	0.09	0.10	0.11	0.12	2.0%
Delivered Energy	**26.88**	**27.07**	**31.85**	**34.75**	**37.39**	**40.04**	**1.8%**
Electricity Related Losses	0.17	0.17	0.19	0.21	0.22	0.24	1.5%
Total	**27.05**	**27.24**	**32.04**	**34.96**	**37.61**	**40.28**	**1.8%**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.83	8.04	9.51	10.28	11.03	11.78	1.8%
Kerosene	0.09	0.11	0.14	0.14	0.14	0.13	0.6%
Jet Fuel[9]	3.34	3.26	4.04	4.45	4.74	4.89	1.9%
Liquefied Petroleum Gas	2.86	2.75	3.03	3.22	3.42	3.60	1.2%
Motor Gasoline[2]	16.82	16.98	19.49	21.18	22.70	24.45	1.7%
Petrochemical Feedstock	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	0.93	0.97	0.97	1.02	1.03	1.03	0.3%
Other Petroleum[12]	4.45	4.52	4.93	4.94	5.30	5.53	0.9%
Petroleum Subtotal	37.53	37.96	43.58	46.75	49.90	52.98	1.5%
Natural Gas	16.00	15.68	17.33	18.17	18.94	19.70	1.0%
Lease and Plant Fuel[6]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Pipeline Natural Gas	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Natural Gas Subtotal	17.83	17.48	19.23	20.13	21.09	21.85	1.0%
Metallurgical Coal	0.65	0.67	0.55	0.48	0.42	0.37	-2.7%
Steam Coal	1.47	1.50	1.53	1.52	1.52	1.52	0.1%
Net Coal Coke Imports	0.06	0.05	0.06	0.05	0.05	0.05	-0.2%
Coal Subtotal	2.18	2.22	2.14	2.06	2.00	1.94	-0.6%
Renewable Energy[13]	2.25	2.28	2.55	2.67	2.82	2.97	1.2%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	11.84	11.88	13.89	15.11	16.41	17.81	1.9%
Delivered Energy	**71.63**	**71.82**	**81.39**	**86.73**	**92.23**	**97.56**	**1.4%**
Electricity Related Losses	26.35	26.40	29.88	31.57	33.37	35.62	1.4%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Electric Power[14]							
Distillate Fuel	0.20	0.33	0.39	0.40	0.42	0.45	1.4%
Residual Fuel	0.68	0.80	0.87	0.92	0.98	0.98	0.9%
Petroleum Subtotal	0.88	1.13	1.26	1.32	1.40	1.43	1.1%
Natural Gas	5.76	5.06	6.87	8.56	9.64	9.61	3.0%
Steam Coal	19.80	20.49	22.81	23.65	25.28	28.54	1.5%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[15]	3.54	3.62	4.30	4.46	4.75	5.14	1.6%
Electricity Imports	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**38.19**	**38.28**	**43.77**	**46.68**	**49.79**	**53.43**	**1.5%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Total Energy Consumption							
Distillate Fuel	8.03	8.37	9.90	10.68	11.45	12.23	1.7%
Kerosene	0.09	0.11	0.14	0.14	0.14	0.13	0.6%
Jet Fuel[9]	3.34	3.26	4.04	4.45	4.74	4.89	1.9%
Liquefied Petroleum Gas	2.86	2.75	3.03	3.22	3.42	3.60	1.2%
Motor Gasoline[2]	16.82	16.98	19.49	21.18	22.70	24.45	1.7%
Petrochemical Feedstock	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	1.61	1.77	1.84	1.94	2.01	2.02	0.6%
Other Petroleum[12]	4.45	4.52	4.93	4.94	5.30	5.53	0.9%
Petroleum Subtotal	38.41	39.09	44.84	48.07	51.30	54.42	1.5%
Natural Gas	21.76	20.74	24.21	26.73	28.59	29.32	1.6%
Lease and Plant Fuel[6]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Pipeline Natural Gas	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Natural Gas Subtotal	23.59	22.54	26.11	28.69	30.73	31.47	1.5%
Metallurgical Coal	0.65	0.67	0.55	0.48	0.42	0.37	-2.7%
Steam Coal	21.27	21.99	24.34	25.17	26.80	30.07	1.4%
Net Coal Coke Imports	0.06	0.05	0.06	0.05	0.05	0.05	-0.2%
Coal Subtotal	21.98	22.71	24.95	25.71	27.27	30.48	1.3%
Nuclear Power	8.14	7.97	8.49	8.62	8.67	8.67	0.4%
Renewable Energy[16]	5.79	5.89	6.85	7.13	7.57	8.10	1.5%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports	0.07	0.02	0.03	0.07	0.05	0.04	4.1%
Total	**97.99**	**98.22**	**111.27**	**118.29**	**125.60**	**133.18**	**1.4%**
Energy Use and Related Statistics							
Delivered Energy Use	71.63	71.82	81.39	86.73	92.23	97.56	1.4%
Total Energy Use	97.99	98.22	111.27	118.29	125.60	133.18	1.4%
Population (millions)	288.60	291.39	310.12	323.55	336.99	350.64	0.8%
Gross Domestic Product (billion 1996 dollars)	10075	10381	13084	15216	17634	20292	3.1%
Carbon Dioxide Emissions (million metric tons)	5750.5	5788.7	6626.8	7052.4	7519.6	8062.3	1.5%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2002 and 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2002 and 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Residential	**15.02**	**15.81**	**14.33**	**14.98**	**15.64**	**16.13**	**0.1%**
Primary Energy[1]	8.33	9.68	8.35	8.74	9.21	9.62	-0.0%
Petroleum Products[2]	10.04	11.27	10.44	10.76	11.36	11.93	0.3%
Distillate Fuel	8.37	9.57	8.29	8.49	8.85	9.12	-0.2%
Liquefied Petroleum Gas	12.98	14.58	14.25	14.45	15.06	15.65	0.3%
Natural Gas	7.82	9.22	7.79	8.21	8.66	9.07	-0.1%
Electricity	25.22	25.42	22.96	23.63	24.12	24.24	-0.2%
Commercial	**15.06**	**15.63**	**13.76**	**14.87**	**15.70**	**16.20**	**0.2%**
Primary Energy[1]	6.57	7.92	6.81	7.20	7.54	7.82	-0.1%
Petroleum Products[2]	6.95	8.03	7.13	7.28	7.55	7.84	-0.1%
Distillate Fuel	6.15	7.03	6.30	6.49	6.76	7.06	0.0%
Residual Fuel	4.27	4.96	4.26	4.52	4.81	5.08	0.1%
Natural Gas	6.62	8.08	6.87	7.33	7.68	7.96	-0.1%
Electricity	23.35	23.24	19.93	21.25	22.10	22.40	-0.2%
Industrial[3]	**6.39**	**7.78**	**6.85**	**7.24**	**7.75**	**8.13**	**0.2%**
Primary Energy	4.93	6.49	5.55	5.83	6.27	6.64	0.1%
Petroleum Products[2]	6.53	8.29	7.24	7.42	7.88	8.36	0.0%
Distillate Fuel	6.33	7.24	6.78	7.19	7.37	7.73	0.3%
Liquefied Petroleum Gas	8.48	12.57	10.02	10.22	10.74	11.35	-0.5%
Residual Fuel	3.94	4.59	3.87	4.10	4.34	4.62	0.0%
Natural Gas[4]	3.89	5.56	4.37	4.82	5.23	5.47	-0.1%
Metallurgical Coal	1.88	1.85	1.82	1.76	1.75	1.68	-0.4%
Steam Coal	1.60	1.55	1.56	1.55	1.56	1.60	0.1%
Electricity	14.73	15.03	13.84	14.62	15.47	15.75	0.2%
Transportation	**10.07**	**11.46**	**10.95**	**10.95**	**11.16**	**11.46**	**0.0%**
Primary Energy	10.04	11.43	10.93	10.92	11.13	11.44	0.0%
Petroleum Products[2]	10.04	11.43	10.93	10.93	11.13	11.44	0.0%
Distillate Fuel[5]	9.55	10.92	10.76	10.71	10.66	10.85	-0.0%
Jet Fuel[6]	6.05	6.46	6.25	6.29	6.58	6.93	0.3%
Motor Gasoline[7]	11.32	12.93	12.32	12.26	12.52	12.81	-0.0%
Residual Fuel	3.83	4.49	3.74	4.01	4.28	4.56	0.1%
Liquefied Petroleum Gas[8]	15.15	16.65	15.24	15.28	15.66	16.24	-0.1%
Natural Gas[9]	7.23	9.04	8.56	9.11	9.45	9.69	0.3%
Ethanol (E85)[10]	14.65	16.23	17.11	17.37	17.22	18.13	0.5%
Electricity	20.03	20.64	18.81	19.59	19.99	19.96	-0.2%
Average End-Use Energy	**10.26**	**11.50**	**10.56**	**10.95**	**11.42**	**11.83**	**0.1%**
Primary Energy	7.85	9.32	8.61	8.83	9.18	9.55	0.1%
Electricity	21.60	21.74	19.36	20.35	21.11	21.38	-0.1%
Electric Power[11]							
Fossil Fuel Average	1.90	2.24	2.06	2.28	2.45	2.46	0.4%
Petroleum Products	4.37	5.28	4.55	4.77	5.10	5.42	0.1%
Distillate Fuel	5.69	6.48	5.36	5.53	6.01	6.33	-0.1%
Residual Fuel	3.99	4.79	4.19	4.44	4.71	5.00	0.2%
Natural Gas	3.69	5.46	4.27	4.81	5.20	5.44	-0.0%
Steam Coal	1.27	1.28	1.25	1.23	1.25	1.31	0.1%

Table A3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Average Price to All Users[12]							
Petroleum Products[2]	9.09	10.51	9.91	10.00	10.29	10.66	0.1%
Distillate Fuel	8.71	9.90	9.53	9.72	9.79	10.03	0.1%
Jet Fuel	6.05	6.46	6.25	6.29	6.58	6.93	0.3%
Liquefied Petroleum Gas	9.52	13.04	10.99	11.21	11.74	12.34	-0.3%
Motor Gasoline[7]	11.32	12.93	12.31	12.25	12.51	12.80	-0.0%
Residual Fuel	3.93	4.66	3.99	4.25	4.52	4.81	0.1%
Natural Gas	5.15	6.86	5.52	5.92	6.30	6.59	-0.2%
Coal	1.29	1.30	1.27	1.25	1.27	1.32	0.1%
Ethanol (E85)[10]	14.65	16.23	17.11	17.37	17.22	18.13	0.5%
Electricity	21.60	21.74	19.36	20.35	21.11	21.38	-0.1%
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)							
Residential	163.90	177.17	175.88	193.21	209.76	223.86	1.1%
Commercial	122.69	128.15	129.92	153.52	177.28	200.93	2.1%
Industrial	124.40	147.11	139.57	152.35	169.93	184.96	1.0%
Transportation	263.73	302.59	341.13	372.46	407.83	449.31	1.8%
Total Non-Renewable Expenditures	674.72	755.02	786.50	871.55	964.80	1059.05	1.5%
Transportation Renewable Expenditures	0.01	0.02	0.03	0.05	0.07	0.08	7.2%
Total Expenditures	**674.73**	**755.04**	**786.54**	**871.60**	**964.87**	**1059.13**	**1.6%**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]*Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.*
Btu = British thermal unit.
Note: Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 prices for motor gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2002 residential and commercial natural gas delivered prices: EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2002 and 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 transportation sector natural gas delivered prices are based on EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and estimated state and federal taxes. 2003 transportation sector natural gas delivered prices are model results. 2002 and 2003 coal prices based on: EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2002 and 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Households (millions)							
Single-Family	74.87	76.15	84.29	89.62	94.55	99.50	1.2%
Multifamily	29.22	29.51	31.12	32.34	33.69	35.08	0.8%
Mobile Homes	6.38	6.35	6.63	7.15	7.55	7.90	1.0%
Total	**110.47**	**112.01**	**122.03**	**129.11**	**135.78**	**142.48**	**1.1%**
Average House Square Footage	**1730**	**1742**	**1823**	**1871**	**1912**	**1950**	**0.5%**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	102.3	103.6	103.8	102.9	101.6	100.1	-0.2%
Total Energy Consumption	189.4	190.3	192.4	190.4	188.3	186.8	-0.1%
(thousand Btu per square foot)							
Delivered Energy Consumption	59.1	59.5	57.0	55.0	53.1	51.3	-0.7%
Total Energy Consumption	109.5	109.2	105.5	101.8	98.5	95.8	-0.6%
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.39	0.40	0.44	0.45	0.46	0.47	0.7%
Space Cooling	0.71	0.65	0.71	0.73	0.76	0.80	0.9%
Water Heating	0.37	0.37	0.38	0.38	0.38	0.37	0.1%
Refrigeration	0.41	0.40	0.36	0.35	0.35	0.36	-0.5%
Cooking	0.10	0.10	0.11	0.12	0.13	0.13	1.1%
Clothes Dryers	0.24	0.24	0.26	0.26	0.27	0.29	0.8%
Freezers	0.13	0.13	0.12	0.12	0.12	0.13	-0.1%
Lighting	0.76	0.78	0.92	0.99	1.06	1.13	1.7%
Clothes Washers[1]	0.03	0.03	0.04	0.05	0.06	0.06	3.3%
Dishwashers[1]	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Color Televisions	0.12	0.13	0.19	0.23	0.27	0.28	3.5%
Personal Computers	0.07	0.07	0.10	0.12	0.13	0.15	3.5%
Furnace Fans	0.08	0.08	0.10	0.10	0.11	0.12	1.5%
Other Uses[2]	0.88	0.95	1.26	1.46	1.65	1.85	3.1%
Delivered Energy	**4.32**	**4.37**	**5.02**	**5.40**	**5.79**	**6.18**	**1.6%**
Natural Gas							
Space Heating	3.52	3.70	4.00	4.17	4.28	4.36	0.8%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	12.9%
Water Heating	1.14	1.17	1.27	1.29	1.30	1.32	0.6%
Cooking	0.21	0.21	0.23	0.25	0.26	0.27	1.2%
Clothes Dryers	0.07	0.07	0.09	0.10	0.11	0.12	2.3%
Other Uses[3]	0.10	0.10	0.10	0.10	0.10	0.09	-0.3%
Delivered Energy	**5.04**	**5.25**	**5.68**	**5.90**	**6.05**	**6.17**	**0.7%**
Distillate							
Space Heating	0.79	0.84	0.78	0.77	0.73	0.68	-1.0%
Water Heating	0.13	0.12	0.12	0.11	0.10	0.10	-1.0%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Delivered Energy	**0.92**	**0.96**	**0.90**	**0.88**	**0.83**	**0.77**	**-1.0%**
Liquefied Petroleum Gas							
Space Heating	0.31	0.30	0.29	0.30	0.31	0.30	0.1%
Water Heating	0.05	0.05	0.05	0.05	0.05	0.05	0.1%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.6%
Other Uses[3]	0.18	0.17	0.20	0.23	0.26	0.28	2.4%
Delivered Energy	**0.57**	**0.54**	**0.57**	**0.61**	**0.64**	**0.67**	**0.9%**
Marketed Renewables (wood)[5]	0.39	0.40	0.40	0.39	0.39	0.38	-0.3%
Other Fuels[6]	0.07	0.08	0.10	0.10	0.10	0.10	0.6%

Table A4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Delivered Energy Consumption by End-Use							
Space Heating	5.46	5.72	6.00	6.19	6.26	6.29	0.4%
Space Cooling	0.71	0.65	0.71	0.73	0.76	0.80	0.9%
Water Heating	1.69	1.71	1.82	1.83	1.84	1.85	0.3%
Refrigeration	0.41	0.40	0.36	0.35	0.35	0.36	-0.5%
Cooking	0.34	0.34	0.37	0.39	0.42	0.44	1.1%
Clothes Dryers	0.31	0.31	0.35	0.37	0.38	0.40	1.2%
Freezers	0.13	0.13	0.12	0.12	0.12	0.13	-0.1%
Lighting	0.76	0.78	0.92	0.99	1.06	1.13	1.7%
Clothes Washers	0.03	0.03	0.04	0.05	0.06	0.06	3.3%
Dishwashers	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Color Televisions	0.12	0.13	0.19	0.23	0.27	0.28	3.5%
Personal Computers	0.07	0.07	0.10	0.12	0.13	0.15	3.5%
Furnace Fans	0.08	0.08	0.10	0.10	0.11	0.12	1.5%
Other Uses[7]	1.16	1.22	1.56	1.79	2.00	2.23	2.8%
Delivered Energy	**11.30**	**11.61**	**12.67**	**13.29**	**13.80**	**14.26**	**0.9%**
Electricity Related Losses	**9.62**	**9.71**	**10.80**	**11.29**	**11.77**	**12.35**	**1.1%**
Total Energy Consumption by End-Use							
Space Heating	6.32	6.61	6.94	7.13	7.21	7.22	0.4%
Space Cooling	2.29	2.11	2.24	2.27	2.32	2.41	0.6%
Water Heating	2.51	2.53	2.64	2.63	2.61	2.60	0.1%
Refrigeration	1.33	1.30	1.15	1.08	1.07	1.08	-0.8%
Cooking	0.56	0.57	0.61	0.64	0.67	0.70	0.9%
Clothes Dryers	0.84	0.85	0.91	0.92	0.94	0.97	0.6%
Freezers	0.43	0.42	0.37	0.37	0.37	0.38	-0.4%
Lighting	2.45	2.51	2.91	3.07	3.21	3.39	1.4%
Clothes Washers	0.10	0.10	0.13	0.15	0.18	0.19	2.9%
Dishwashers	0.08	0.08	0.08	0.09	0.09	0.09	0.8%
Color Televisions	0.40	0.43	0.60	0.70	0.81	0.85	3.2%
Personal Computers	0.22	0.23	0.32	0.37	0.41	0.45	3.2%
Furnace Fans	0.26	0.27	0.31	0.32	0.33	0.35	1.2%
Other Uses[7]	3.13	3.32	4.28	4.83	5.35	5.93	2.7%
Total	**20.92**	**21.31**	**23.47**	**24.58**	**25.56**	**26.62**	**1.0%**
Non-Marketed Renewables							
Geothermal[8]	0.00	0.00	0.00	0.01	0.01	0.01	7.6%
Solar[9]	0.02	0.02	0.03	0.03	0.04	0.04	2.7%
Total	**0.02**	**0.02**	**0.03**	**0.04**	**0.04**	**0.05**	**3.3%**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and spa heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2001*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Total Floorspace (billion square feet)							
Surviving	68.8	70.1	79.0	85.9	93.6	101.8	1.7%
New Additions	2.1	2.1	2.3	2.5	2.6	3.0	1.6%
Total	**70.9**	**72.1**	**81.2**	**88.4**	**96.2**	**104.8**	**1.7%**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	116.0	114.8	117.3	117.7	118.3	119.2	0.2%
Electricity Related Losses	129.4	127.2	132.5	133.1	133.7	136.0	0.3%
Total Energy Consumption	245.4	242.0	249.7	250.8	252.0	255.2	0.2%
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.14	0.15	0.16	0.16	0.16	0.16	0.4%
Space Cooling[1]	0.46	0.42	0.45	0.48	0.51	0.54	1.2%
Water Heating[1]	0.14	0.14	0.15	0.15	0.16	0.16	0.7%
Ventilation	0.16	0.16	0.17	0.18	0.19	0.20	0.9%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	-0.1%
Lighting	1.09	1.10	1.28	1.37	1.44	1.52	1.5%
Refrigeration	0.20	0.20	0.23	0.24	0.26	0.28	1.6%
Office Equipment (PC)	0.13	0.14	0.24	0.29	0.33	0.36	4.5%
Office Equipment (non-PC)	0.31	0.31	0.45	0.57	0.70	0.87	4.8%
Other Uses[2]	1.47	1.48	1.84	2.17	2.56	3.00	3.3%
Delivered Energy	**4.12**	**4.13**	**5.00**	**5.63**	**6.33**	**7.12**	**2.5%**
Natural Gas							
Space Heating[1]	1.32	1.36	1.43	1.47	1.51	1.56	0.7%
Space Cooling[1]	0.01	0.01	0.02	0.02	0.02	0.03	4.0%
Water Heating[1]	0.57	0.57	0.66	0.72	0.78	0.85	1.8%
Cooking	0.26	0.26	0.31	0.34	0.37	0.40	2.0%
Other Uses[3]	1.03	1.02	1.08	1.15	1.23	1.33	1.2%
Delivered Energy	**3.20**	**3.22**	**3.49**	**3.69**	**3.91**	**4.17**	**1.2%**
Distillate							
Space Heating[1]	0.20	0.22	0.32	0.37	0.42	0.47	3.5%
Water Heating[1]	0.07	0.07	0.07	0.07	0.08	0.08	0.4%
Other Uses[4]	0.23	0.23	0.22	0.22	0.21	0.21	-0.3%
Delivered Energy	**0.50**	**0.52**	**0.62**	**0.66**	**0.71**	**0.77**	**1.8%**
Marketed Renewables (biomass)	0.08	0.09	0.09	0.09	0.09	0.09	0.0%
Other Fuels[5]	0.33	0.33	0.34	0.34	0.34	0.35	0.2%
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.66	1.73	1.90	2.00	2.09	2.20	1.1%
Space Cooling[1]	0.47	0.43	0.47	0.49	0.53	0.57	1.3%
Water Heating[1]	0.77	0.78	0.88	0.94	1.01	1.09	1.5%
Ventilation	0.16	0.16	0.17	0.18	0.19	0.20	0.9%
Cooking	0.29	0.29	0.34	0.37	0.40	0.43	1.8%
Lighting	1.09	1.10	1.28	1.37	1.44	1.52	1.5%
Refrigeration	0.20	0.20	0.23	0.24	0.26	0.28	1.6%
Office Equipment (PC)	0.13	0.14	0.24	0.29	0.33	0.36	4.5%
Office Equipment (non-PC)	0.31	0.31	0.45	0.57	0.70	0.87	4.8%
Other Uses[6]	3.14	3.15	3.56	3.96	4.43	4.98	2.1%
Delivered Energy	**8.23**	**8.29**	**9.53**	**10.41**	**11.38**	**12.49**	**1.9%**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electricity Related Losses	**9.18**	**9.18**	**10.76**	**11.77**	**12.86**	**14.25**	**2.0%**
Total Energy Consumption by End-Use							
Space Heating[1]	1.98	2.06	2.24	2.32	2.41	2.52	0.9%
Space Cooling[1]	1.48	1.37	1.44	1.49	1.56	1.66	0.9%
Water Heating[1]	1.08	1.08	1.20	1.26	1.33	1.41	1.2%
Ventilation	0.52	0.52	0.55	0.55	0.56	0.59	0.6%
Cooking	0.36	0.36	0.41	0.43	0.46	0.49	1.4%
Lighting	3.51	3.55	4.04	4.23	4.36	4.56	1.1%
Refrigeration	0.64	0.65	0.71	0.75	0.80	0.85	1.2%
Office Equipment (PC)	0.43	0.44	0.76	0.90	1.01	1.08	4.2%
Office Equipment (non-PC)	0.99	1.00	1.41	1.75	2.13	2.61	4.5%
Other Uses[6]	6.41	6.44	7.52	8.49	9.63	10.98	2.5%
Total	**17.40**	**17.46**	**20.29**	**22.18**	**24.24**	**26.74**	**2.0%**
Non-Marketed Renewable Fuels							
Solar[7]	0.02	0.02	0.03	0.03	0.03	0.04	2.1%

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
N/A = Not applicable.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Value of Shipments (billion 1996 dollars)							
Manufacturing	3826	3851	4836	5392	6046	6733	2.6%
Nonmanufacturing	1240	1254	1329	1458	1587	1736	1.5%
Total	**5067**	**5105**	**6165**	**6850**	**7633**	**8469**	**2.3%**
Energy Prices (2003 dollars per million Btu)							
Distillate Oil	6.33	7.24	6.78	7.19	7.37	7.73	0.3%
Liquefied Petroleum Gas	8.48	12.57	10.02	10.22	10.74	11.35	-0.5%
Residual Oil	3.94	4.59	3.87	4.10	4.34	4.62	0.0%
Motor Gasoline	11.22	12.79	11.68	11.62	11.90	12.21	-0.2%
Natural Gas	3.89	5.56	4.37	4.82	5.23	5.47	-0.1%
Metallurgical Coal	1.88	1.85	1.82	1.76	1.75	1.68	-0.4%
Steam Coal	1.60	1.55	1.56	1.55	1.56	1.60	0.1%
Electricity	14.73	15.03	13.84	14.62	15.47	15.75	0.2%
Energy Consumption (quadrillion Btu)[1]							
Distillate	0.99	1.03	1.04	1.08	1.14	1.19	0.7%
Liquefied Petroleum Gas	2.17	2.09	2.30	2.44	2.59	2.74	1.2%
Petrochemical Feedstocks	1.22	1.32	1.48	1.52	1.55	1.57	0.8%
Residual Fuel	0.21	0.28	0.34	0.38	0.38	0.38	1.4%
Motor Gasoline	0.30	0.31	0.31	0.33	0.35	0.37	0.9%
Petroleum Coke	1.02	1.00	1.07	1.17	1.30	1.38	1.5%
Still Gas	1.40	1.48	1.77	1.57	1.65	1.68	0.6%
Asphalt and Road Oil	1.24	1.22	1.16	1.21	1.30	1.43	0.7%
Miscellaneous Petroleum[2]	0.60	0.61	0.69	0.73	0.77	0.75	1.0%
Petroleum Subtotal	9.15	9.31	10.17	10.43	11.03	11.47	1.0%
Natural Gas	7.75	7.19	8.10	8.50	8.89	9.26	1.2%
Lease and Plant Fuel[3]	1.14	1.15	1.20	1.23	1.32	1.31	0.6%
Natural Gas Subtotal	8.90	8.34	9.31	9.73	10.21	10.57	1.1%
Metallurgical Coal and Coke[4]	0.71	0.72	0.61	0.53	0.47	0.42	-2.4%
Steam Coal	1.37	1.39	1.42	1.42	1.42	1.42	0.1%
Coal Subtotal	2.08	2.11	2.03	1.95	1.89	1.83	-0.6%
Renewables[5]	1.78	1.79	2.07	2.19	2.34	2.50	1.5%
Purchased Electricity	3.32	3.31	3.78	3.98	4.19	4.39	1.3%
Delivered Energy	**25.23**	**24.86**	**27.35**	**28.27**	**29.66**	**30.76**	**1.0%**
Electricity Related Losses	7.38	7.35	8.13	8.31	8.52	8.78	0.8%
Total	**32.61**	**32.21**	**35.47**	**36.58**	**38.19**	**39.53**	**0.9%**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)							
Distillate	0.19	0.20	0.17	0.16	0.15	0.14	-1.6%
Liquefied Petroleum Gas	0.43	0.41	0.37	0.36	0.34	0.32	-1.1%
Petrochemical Feedstocks	0.24	0.26	0.24	0.22	0.20	0.19	-1.5%
Residual Fuel	0.04	0.05	0.05	0.06	0.05	0.04	-0.9%
Motor Gasoline	0.06	0.06	0.05	0.05	0.05	0.04	-1.4%
Petroleum Coke	0.20	0.20	0.17	0.17	0.17	0.16	-0.8%
Still Gas	0.28	0.29	0.29	0.23	0.22	0.20	-1.7%
Asphalt and Road Oil	0.24	0.24	0.19	0.18	0.17	0.17	-1.6%
Miscellaneous Petroleum[2]	0.12	0.12	0.11	0.11	0.10	0.09	-1.3%
Petroleum Subtotal	1.81	1.82	1.65	1.52	1.44	1.35	-1.3%
Natural Gas	1.53	1.41	1.31	1.24	1.16	1.09	-1.1%
Lease and Plant Fuel[3]	0.23	0.23	0.20	0.18	0.17	0.15	-1.7%
Natural Gas Subtotal	1.76	1.63	1.51	1.42	1.34	1.25	-1.2%
Metallurgical Coal and Coke[4]	0.14	0.14	0.10	0.08	0.06	0.05	-4.7%
Steam Coal	0.27	0.27	0.23	0.21	0.19	0.17	-2.2%
Coal Subtotal	0.41	0.41	0.33	0.28	0.25	0.22	-2.9%
Renewables[5]	0.35	0.35	0.34	0.32	0.31	0.29	-0.8%
Purchased Electricity	0.65	0.65	0.61	0.58	0.55	0.52	-1.0%
Delivered Energy	**4.98**	**4.87**	**4.44**	**4.13**	**3.89**	**3.63**	**-1.3%**
Electricity Related Losses	1.46	1.44	1.32	1.21	1.12	1.04	-1.5%
Total	**6.44**	**6.31**	**5.75**	**5.34**	**5.00**	**4.67**	**-1.4%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Industrial Combined Heat and Power							
Capacity (gigawatts)	24.95	24.87	29.50	32.23	36.03	40.09	2.2%
Generation (billion kilowatthours)	147.19	139.59	171.71	192.47	220.64	250.10	2.7%

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2002 and 2003 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2002 and 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 consumption values based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 shipments: Global Insight industry model, August 2004. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Key Indicators							
Level of Travel							
(billion vehicle miles traveled)							
Light-Duty Vehicles less than 8,500 pounds	2557	2602	3017	3354	3680	4053	2.0%
Commercial Light Trucks[1]	64	65	78	87	96	107	2.3%
Freight Trucks greater than 10,000 pounds	210	214	268	300	336	373	2.6%
(billion seat miles available)							
Air	908	932	1152	1327	1455	1520	2.2%
(billion ton miles traveled)							
Rail	1328	1352	1576	1690	1833	2001	1.8%
Domestic Shipping	606	592	649	669	706	733	1.0%
Energy Efficiency Indicators							
(miles per gallon)							
New Light-Duty Vehicle[2]	24.6	25.1	25.7	26.1	26.5	26.9	0.3%
New Car[2]	28.9	29.5	29.7	30.3	30.6	31.0	0.2%
New Light Truck[2]	21.3	21.8	22.9	23.4	24.1	24.6	0.6%
Light-Duty Stock[3]	20.0	20.0	20.1	20.4	20.7	21.0	0.2%
New Commercial Light Truck[1]	14.1	14.6	15.2	15.6	16.0	16.4	0.5%
Stock Commercial Light Truck[1]	13.8	14.0	14.7	15.1	15.5	15.9	0.6%
Freight Truck	6.0	6.0	6.0	6.2	6.4	6.6	0.4%
(seat miles per gallon)							
Aircraft	55.2	55.3	59.2	62.1	65.2	68.5	1.0%
(ton miles per thousand Btu)							
Rail	2.9	2.9	3.1	3.3	3.4	3.6	1.0%
Domestic Shipping	2.3	2.3	2.3	2.4	2.4	2.4	0.2%
Energy Use by Mode							
(quadrillion Btu)							
Light-Duty Vehicles	15.58	15.78	18.45	20.24	21.85	23.69	1.9%
Commercial Light Trucks[1]	0.58	0.58	0.67	0.72	0.78	0.84	1.7%
Bus Transportation	0.24	0.25	0.26	0.27	0.27	0.27	0.3%
Freight Trucks	4.39	4.46	5.56	6.11	6.60	7.10	2.1%
Rail, Passenger	0.11	0.12	0.13	0.15	0.16	0.17	1.7%
Rail, Freight	0.47	0.47	0.51	0.52	0.54	0.56	0.8%
Shipping, Domestic	0.26	0.26	0.28	0.29	0.30	0.31	0.8%
Shipping, International	0.59	0.56	0.51	0.52	0.52	0.52	-0.3%
Recreational Boats	0.31	0.31	0.33	0.35	0.37	0.39	1.0%
Air	2.87	2.74	3.43	3.83	4.11	4.25	2.0%
Military Use	0.64	0.69	0.80	0.81	0.82	0.83	0.9%
Lubricants	0.20	0.20	0.21	0.23	0.25	0.27	1.4%
Pipeline Fuel	0.69	0.65	0.70	0.73	0.82	0.84	1.2%
Total	**26.92**	**27.07**	**31.85**	**34.75**	**37.39**	**40.04**	**1.8%**
(million barrels per day oil equivalent)							
Light-Duty Vehicles	8.19	8.29	9.72	10.65	11.49	12.45	1.9%
Commercial Light Trucks[1]	0.30	0.30	0.35	0.38	0.41	0.44	1.7%
Bus Transportation	0.12	0.12	0.13	0.13	0.13	0.13	0.3%
Freight Trucks	2.09	2.13	2.66	2.92	3.16	3.40	2.2%
Rail, Passenger	0.05	0.06	0.06	0.07	0.07	0.08	1.7%
Rail, Freight	0.22	0.22	0.24	0.25	0.25	0.26	0.8%
Shipping, Domestic	0.12	0.12	0.13	0.13	0.14	0.14	0.8%
Shipping, International	0.26	0.25	0.22	0.23	0.23	0.23	-0.3%
Recreational Boats	0.16	0.16	0.18	0.19	0.19	0.20	1.0%
Air	1.39	1.33	1.66	1.85	1.99	2.06	2.0%
Military Use	0.31	0.33	0.39	0.39	0.40	0.40	0.9%
Lubricants	0.09	0.09	0.10	0.11	0.12	0.13	1.4%
Pipeline Fuel	0.35	0.33	0.35	0.37	0.42	0.43	1.2%
Total	**13.65**	**13.73**	**16.19**	**17.67**	**19.00**	**20.36**	**1.8%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004); Federal Highway Administration, *Highway Statistics 2001* (Washington, DC, November 2002); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 2001*, DOE/EIA-0214(2001) (Washington, DC, November 2004) U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2003/2002* (Washington, DC, 2003); EIA, *Fuel Oil and Kerosene Sales 2002*, DOE/EIA-0535(2002) (Washington, DC, November 2003); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Generation by Fuel Type							
Electric Power Sector[1]							
Power Only[2]							
Coal	1881	1916	2169	2251	2440	2836	1.8%
Petroleum	83	106	112	118	124	128	0.9%
Natural Gas[3]	457	407	634	854	1038	1048	4.4%
Nuclear Power	780	764	813	826	830	830	0.4%
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	0.1%
Renewable Sources[4]	311	318	389	398	412	430	1.4%
Distributed Generation (Natural Gas)	0	0	0	0	1	3	N/A
Total	**3503**	**3501**	**4109**	**4438**	**4836**	**5267**	**1.9%**
Combined Heat and Power[5]							
Coal	31	34	33	34	34	33	-0.1%
Petroleum	7	7	6	7	7	7	0.1%
Natural Gas	151	149	188	200	196	186	1.0%
Renewable Sources	6	6	4	4	4	4	-1.7%
Total	**197**	**197**	**230**	**244**	**240**	**230**	**0.7%**
Total Net Generation	**3700**	**3699**	**4339**	**4683**	**5076**	**5497**	**1.8%**
Less Direct Use	50	50	66	65	65	65	1.2%
Net Available to the Grid	**3650**	**3649**	**4273**	**4617**	**5011**	**5432**	**1.8%**
Commercial and Industrial Generation[6]							
Coal	21	21	21	21	21	21	N/A
Petroleum	5	6	9	10	12	13	3.8%
Natural Gas	83	76	100	117	141	169	3.7%
Other Gaseous Fuels[7]	6	6	4	5	5	5	-0.4%
Renewable Sources[4]	34	35	43	45	50	55	2.0%
Other[8]	9	10	10	10	10	10	-0.0%
Total	**159**	**153**	**187**	**208**	**238**	**273**	**2.7%**
Less Direct Use	131	126	139	149	164	182	1.7%
Total Sales to the Grid	**28**	**28**	**48**	**59**	**74**	**91**	**5.5%**
Total Electricity Generation	**3860**	**3852**	**4526**	**4890**	**5314**	**5770**	**1.9%**
Total Net Generation to the Grid	**3678**	**3677**	**4322**	**4676**	**5085**	**5522**	**1.9%**
Net Imports	**22**	**5**	**9**	**21**	**15**	**11**	**4.1%**
Electricity Sales by Sector							
Residential	1267	1280	1471	1584	1696	1810	1.6%
Commercial	1208	1210	1466	1651	1854	2088	2.5%
Industrial	972	969	1107	1166	1229	1286	1.3%
Transportation	22	23	26	29	32	35	2.0%
Total	**3469**	**3481**	**4070**	**4430**	**4811**	**5220**	**1.9%**
Direct Use	182	175	204	214	229	248	1.6%
Total Electricity Use	**3651**	**3657**	**4274**	**4644**	**5040**	**5467**	**1.8%**
End-Use Prices[9]							
(2003 cents per kilowatthour)							
Residential	8.6	8.7	7.8	8.1	8.2	8.3	-0.2%
Commercial	8.0	7.9	6.8	7.3	7.5	7.6	-0.2%
Industrial	5.0	5.1	4.7	5.0	5.3	5.4	0.2%
Transportation	6.8	7.0	6.4	6.7	6.8	6.8	-0.2%
All Sectors Average	**7.4**	**7.4**	**6.6**	**6.9**	**7.2**	**7.3**	**-0.1%**
Prices by Service Category[9]							
(2003 cents per kilowatthour)							
Generation	4.7	4.8	4.1	4.5	4.7	4.9	0.1%
Transmission	0.6	0.5	0.6	0.6	0.7	0.7	1.0%
Distribution	2.1	2.1	2.0	1.9	1.8	1.8	-0.7%

Table A8. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electric Power Sector Emissions[1]							
Sulfur Dioxide (million tons)	10.19	10.59	9.29	8.97	8.95	8.95	-0.8%
Nitrogen Oxide (million tons)	4.37	4.12	3.99	4.09	4.18	4.29	0.2%
Mercury (tons)	50.08	49.70	54.08	55.12	55.45	55.97	0.5%

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), and supporting databases. 2002 and 2003 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2002 and 2003 prices: EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electric Power Sector[2]							
Power Only[3]							
Coal Steam	305.8	305.2	304.6	310.6	334.6	389.2	1.1%
Other Fossil Steam[4]	131.5	128.6	119.4	101.1	100.0	99.4	-1.2%
Combined Cycle	70.3	106.9	136.4	147.9	176.8	189.4	2.6%
Combustion Turbine/Diesel	118.6	124.8	132.7	141.8	168.0	188.6	1.9%
Nuclear Power[5]	98.9	99.2	100.6	102.2	102.7	102.7	0.2%
Pumped Storage	20.7	20.8	20.9	20.9	20.9	20.9	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	90.2	92.0	95.0	96.3	99.0	102.9	0.5%
Distributed Generation[7]	0.0	0.0	0.4	1.1	3.1	6.9	N/A
Total	**836.1**	**877.5**	**909.9**	**921.9**	**1005.0**	**1100.0**	**1.0%**
Combined Heat and Power[8]							
Coal Steam	5.1	5.1	5.1	5.0	5.0	5.0	0.0%
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	N/A
Combined Cycle	29.1	31.3	33.5	33.5	33.5	33.5	0.3%
Combustion Turbine/Diesel	5.1	5.1	5.1	5.1	5.1	5.1	0.0%
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	N/A
Total	**40.6**	**42.8**	**45.1**	**45.0**	**45.0**	**45.0**	**0.2%**
Cumulative Planned Additions[9]							
Coal Steam	0.0	0.0	1.8	1.8	1.8	1.8	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	28.3	28.3	28.3	28.3	N/A
Combustion Turbine/Diesel	0.0	0.0	3.9	3.9	3.9	3.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	2.7	2.8	2.9	3.0	N/A
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**0.0**	**0.0**	**36.7**	**36.8**	**36.9**	**37.0**	**N/A**
Cumulative Unplanned Additions[9]							
Coal Steam	0.0	0.0	0.0	6.5	30.6	85.1	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	3.5	15.3	44.2	56.8	N/A
Combustion Turbine/Diesel	0.0	0.0	5.9	19.7	47.4	69.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.2	1.3	4.0	7.7	N/A
Distributed Generation[7]	0.0	0.0	0.4	1.1	3.1	6.9	N/A
Total	**0.0**	**0.0**	**9.9**	**44.0**	**129.1**	**226.4**	**N/A**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**46.6**	**80.8**	**166.0**	**263.4**	**N/A**
Cumulative Retirements[10]							
Coal Steam	0.0	0.0	2.4	3.0	3.0	3.0	N/A
Other Fossil Steam[4]	0.0	0.0	9.3	27.5	28.6	29.2	N/A
Combined Cycle	0.0	0.0	0.1	0.4	0.4	0.4	N/A
Combustion Turbine/Diesel	0.0	0.0	1.9	6.6	8.1	9.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Total	**0.0**	**0.0**	**13.8**	**37.6**	**40.1**	**42.6**	**N/A**
Total Electric Power Sector Capacity	**876.7**	**920.3**	**954.9**	**966.9**	**1050.0**	**1145.0**	**1.0%**

Table A9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Commercial and Industrial Generators[11]							
Coal	4.2	4.1	4.1	4.1	4.1	4.1	-0.0%
Petroleum	1.0	0.7	1.5	1.5	1.7	1.7	4.2%
Natural Gas	14.2	14.4	17.4	19.7	22.8	26.7	2.9%
Other Gaseous Fuels	1.8	1.8	1.5	1.6	1.6	1.7	-0.3%
Renewable Sources[6]	5.4	5.4	6.8	7.3	8.3	9.9	2.7%
Other	0.7	0.7	0.7	0.7	0.7	0.7	N/A
Total	**27.2**	**27.1**	**32.1**	**34.9**	**39.2**	**44.8**	**2.3%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**5.0**	**7.8**	**12.1**	**17.7**	**N/A**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.5 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2003.
[10]Cumulative retirements after December 31, 2003.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	138.9	136.7	105.5	82.4	50.6	37.9	-5.7%
Gross Domestic Economy Trade	173.9	198.5	206.9	178.8	133.2	101.6	-3.0%
Gross Domestic Trade	**312.8**	**335.2**	**312.3**	**261.2**	**183.8**	**139.5**	**-3.9%**
Gross Domestic Firm Power Sales (million 2003 dollars)	7037.4	6926.5	5344.6	4176.6	2564.5	1919.7	-5.7%
Gross Domestic Economy Sales (million 2003 dollars)	5357.4	7959.8	7280.2	7408.5	5938.8	4682.6	-2.4%
Gross Domestic Sales (million 2003 dollars)	**12394.7**	**14886.3**	**12624.9**	**11585.1**	**8503.3**	**6602.3**	**-3.6%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	9.5	11.3	2.2	1.5	0.5	0.0	-23.4%
Economy Imports From Canada and Mexico	26.8	18.2	29.3	38.7	31.0	25.1	1.5%
Gross Imports From Canada and Mexico	**36.3**	**29.5**	**31.4**	**40.2**	**31.5**	**25.2**	**-0.7%**
Firm Power Exports To Canada and Mexico	5.6	5.5	1.0	0.7	0.2	0.0	N/A
Economy Exports To Canada and Mexico	8.7	19.5	21.3	18.3	15.9	14.0	-1.5%
Gross Exports To Canada and Mexico	**14.3**	**24.9**	**22.3**	**18.9**	**16.1**	**14.0**	**-2.6%**

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2002 and 2003 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 1999. 2002 and 2003 Mexican electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 2002 Canadian international electricity trade data: National Energy Board, *Annual Report 2001*. 2003 Canadian electricity trade data: National Energy Board, *Annual Report 2002*. **Projections:** Energy Information Administration, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Crude Oil							
Domestic Crude Production[1]	5.74	5.68	6.02	5.49	5.21	4.73	-0.8%
Alaska	0.98	0.97	0.81	0.88	0.86	0.61	-2.1%
Lower 48 States	4.75	4.71	5.22	4.61	4.35	4.12	-0.6%
Net Imports	9.13	9.65	11.31	13.28	14.80	16.11	2.4%
Gross Imports	9.14	9.66	11.32	13.29	14.81	16.12	2.4%
Exports	0.01	0.01	0.01	0.01	0.01	0.01	-0.9%
Other Crude Supply[2]	0.07	-0.03	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**14.94**	**15.31**	**17.33**	**18.77**	**20.01**	**20.84**	**1.4%**
Other Petroleum Supply							
Natural Gas Plant Liquids	1.88	1.72	1.96	1.96	2.04	2.04	0.8%
Net Product Imports	1.41	1.58	2.06	2.12	2.31	3.00	2.9%
Gross Refined Product Imports[3]	1.61	1.85	1.99	1.87	1.90	2.47	1.3%
Unfinished Oil Imports	0.41	0.34	0.59	0.76	0.91	1.02	5.2%
Blending Components	0.37	0.41	0.48	0.52	0.55	0.60	1.7%
Exports	0.97	1.01	0.99	1.03	1.05	1.08	0.3%
Refinery Processing Gain[4]	0.98	1.00	1.11	1.36	1.50	1.56	2.0%
Other Inputs[5]	0.67	0.69	0.53	0.46	0.46	0.50	-1.5%
Total Primary Supply[6]	**19.89**	**20.30**	**22.98**	**24.67**	**26.32**	**27.93**	**1.5%**
Refined Petroleum Products Supplied							
Motor Gasoline[7]	8.85	8.93	10.28	11.17	11.97	12.89	1.7%
Jet Fuel[8]	1.61	1.57	1.95	2.15	2.29	2.36	1.9%
Distillate Fuel[9]	3.79	3.95	4.70	5.07	5.44	5.81	1.8%
Residual Fuel	0.70	0.77	0.80	0.85	0.88	0.88	0.6%
Other[10]	4.75	4.77	5.25	5.42	5.74	5.98	1.0%
Total	**19.71**	**20.00**	**22.98**	**24.67**	**26.32**	**27.93**	**1.5%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.26	1.28	1.33	1.38	1.41	1.42	0.5%
Industrial[11]	4.82	4.87	5.33	5.49	5.81	6.05	1.0%
Transportation	13.24	13.35	15.76	17.21	18.48	19.82	1.8%
Electric Power[12]	0.39	0.50	0.56	0.59	0.62	0.64	1.1%
Total	**19.71**	**20.00**	**22.98**	**24.67**	**26.32**	**27.93**	**1.5%**
Discrepancy[13]	**0.18**	**0.29**	**-0.00**	**0.00**	**0.00**	**-0.00**	**N/A**
World Oil Price (2003 dollars per barrel)[14]	24.10	27.73	25.00	26.75	28.50	30.31	0.4%
Import Share of Product Supplied	0.54	0.56	0.58	0.62	0.65	0.68	0.9%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2003 dollars)	91.94	113.78	125.14	153.97	180.07	215.89	3.0%
Domestic Refinery Distillation Capacity[15]	16.8	16.8	18.7	20.2	21.4	22.3	1.3%
Capacity Utilization Rate (percent)	91.0	93.0	94.0	94.2	94.8	94.9	0.1%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers; natural gas converted to liquid fuel; and coal converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[12]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Average refiner acquisition cost for imported crude oil.
[15]End-of-year operable capacity.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2002 data: EIA, *Petroleum Supply Annual 2002*, DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2003 data: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A12. Petroleum Product Prices
(2003 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
World Oil Price (2003 dollars per barrel)	**24.10**	**27.73**	**25.00**	**26.75**	**28.50**	**30.31**	**0.4%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	116.1	132.7	114.9	117.7	122.7	126.4	-0.2%
Liquefied Petroleum Gas	111.6	125.4	122.6	124.2	129.5	134.6	0.3%
Commercial							
Distillate Fuel	85.1	97.3	86.9	89.5	93.2	97.3	0.0%
Residual Fuel	63.9	74.3	63.7	67.7	71.9	76.0	0.1%
Residual Fuel (2003 dollars per barrel)	26.84	31.21	26.77	28.44	30.21	31.92	0.1%
Industrial[1]							
Distillate Fuel	87.7	100.2	93.3	98.8	101.2	106.2	0.3%
Liquefied Petroleum Gas	73.0	108.1	86.1	87.9	92.3	97.6	-0.5%
Residual Fuel	59.0	68.7	57.9	61.4	64.9	69.1	0.0%
Residual Fuel (2003 dollars per barrel)	24.76	28.84	24.33	25.77	27.27	29.02	0.0%
Transportation							
Diesel Fuel (distillate)[2]	131.6	150.4	147.5	146.8	146.1	148.6	-0.1%
Jet Fuel[3]	81.7	87.2	84.3	85.0	88.8	93.5	0.3%
Motor Gasoline[4]	140.4	160.3	152.4	151.6	154.9	158.5	-0.1%
Liquid Petroleum Gas	130.3	143.2	131.1	131.4	134.7	139.7	-0.1%
Residual Fuel	57.4	67.3	56.0	60.0	64.1	68.3	0.1%
Residual Fuel (2003 dollars per barrel)	24.09	28.25	23.50	25.21	26.92	28.68	0.1%
Ethanol (E85)[5]	137.6	152.4	160.5	163.0	161.6	170.1	0.5%
Electric Power[6]							
Distillate Fuel	79.0	89.8	74.4	76.7	83.3	87.8	-0.1%
Residual Fuel	59.7	71.7	62.7	66.5	70.5	74.9	0.2%
Residual Fuel (2003 dollars per barrel)	25.05	30.12	26.32	27.91	29.63	31.45	0.2%
Refined Petroleum Product Prices[7]							
Distillate Fuel	120.3	136.7	131.0	133.4	134.4	137.7	0.0%
Jet Fuel[3]	81.7	87.2	84.3	85.0	88.8	93.5	0.3%
Liquefied Petroleum Gas	81.8	112.1	94.5	96.4	101.0	106.1	-0.3%
Motor Gasoline[4]	140.4	160.3	152.2	151.5	154.8	158.4	-0.1%
Residual Fuel	58.8	69.8	59.8	63.6	67.7	72.0	0.1%
Residual Fuel (2003 dollars per barrel)	24.71	29.32	25.11	26.72	28.43	30.22	0.1%
Average	**118.2**	**136.6**	**128.3**	**129.1**	**132.4**	**136.8**	**0.0%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[3]Includes only kerosene type.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: *2002 and 2003 prices for motor gasoline, distillate, and jet fuel are based on:* Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2002 and 2003 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2002 and 2003 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 and 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2002 and 2003 world oil price: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Production							
Dry Gas Production[1]	18.96	19.07	20.42	20.77	21.89	21.83	0.6%
Supplemental Natural Gas[2]	0.07	0.06	0.08	0.08	0.08	0.08	0.7%
Net Imports	3.50	3.24	4.94	7.02	7.89	8.66	4.6%
Canada	3.60	3.13	2.57	2.98	2.69	2.55	-0.9%
Mexico	-0.26	-0.33	-0.14	-0.29	-0.35	-0.25	-1.2%
Liquefied Natural Gas[3]	0.17	0.44	2.50	4.33	5.54	6.37	12.9%
Total Supply	22.53	22.37	25.44	27.86	29.85	30.56	1.4%
Consumption by Sector							
Residential	4.89	5.10	5.52	5.74	5.88	5.99	0.7%
Commercial	3.11	3.13	3.39	3.58	3.80	4.05	1.2%
Industrial[4]	7.53	6.99	7.87	8.26	8.64	9.00	1.2%
Electric Power[5]	5.65	4.96	6.74	8.39	9.45	9.43	3.0%
Transportation[6]	0.01	0.02	0.06	0.08	0.10	0.11	7.8%
Pipeline Fuel	0.67	0.64	0.68	0.71	0.80	0.82	1.2%
Lease and Plant Fuel[7]	1.11	1.12	1.17	1.20	1.29	1.27	0.6%
Total	22.98	21.95	25.44	27.96	29.95	30.67	1.5%
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Discrepancy[8]	-0.45	0.42	-0.00	-0.09	-0.10	-0.11	N/A
Natural Gas Prices (2003 dollars per thousand cubic feet)							
Average Lower 48 Wellhead Price[9]	3.06	4.98	3.64	4.16	4.53	4.79	-0.2%
Delivered Prices							
Residential	8.04	9.49	8.02	8.45	8.91	9.33	-0.1%
Commercial	6.81	8.31	7.07	7.54	7.90	8.19	-0.1%
Industrial[4]	4.00	5.72	4.50	4.96	5.38	5.63	-0.1%
Electric Power[5]	3.76	5.57	4.36	4.90	5.31	5.55	-0.0%
Transportation[10]	7.44	9.31	8.81	9.38	9.72	9.98	0.3%
Average[11]	5.29	7.04	5.67	6.08	6.47	6.77	-0.2%

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 and 2001 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). Other 2002 and 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2002 residential and commercial delivered prices: EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 electric power sector prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004. 2002 and 2003 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and estimated state and federal taxes. 2003 transportation sector delivered prices are model results. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Crude Oil							
Lower 48 Average Wellhead Price[1] (2003 dollars per barrel)	24.91	28.60	24.50	26.27	28.06	30.00	0.2%
Production (million barrels per day)[2]							
U.S. Total	5.74	5.68	6.02	5.49	5.21	4.73	-0.8%
Lower 48 Onshore	3.06	2.99	2.63	2.42	2.24	2.09	-1.6%
Lower 48 Offshore	1.69	1.72	2.58	2.19	2.11	2.03	0.8%
Alaska	0.98	0.97	0.81	0.88	0.86	0.61	-2.1%
Lower 48 End of Year Reserves (billion barrels)[2]	19.34	18.94	21.23	18.89	17.79	16.47	-0.6%
Natural Gas							
Lower 48 Average Wellhead Price[1] (2003 dollars per thousand cubic feet)	3.06	4.98	3.64	4.16	4.53	4.79	-0.2%
Dry Production (trillion cubic feet)[3]							
U.S. Total	18.96	19.07	20.42	20.77	21.89	21.83	0.6%
Lower 48 Onshore	13.69	13.89	14.98	15.38	15.30	14.71	0.3%
Associated-Dissolved[4]	1.54	1.54	1.32	1.22	1.15	1.08	-1.6%
Non-Associated	12.15	12.36	13.66	14.16	14.16	13.63	0.4%
Conventional	5.66	5.77	5.60	5.62	5.40	5.02	-0.6%
Unconventional	6.49	6.59	8.06	8.54	8.75	8.61	1.2%
Lower 48 Offshore	4.85	4.73	5.19	5.12	4.70	4.89	0.1%
Associated-Dissolved[4]	1.02	0.99	1.81	1.48	1.39	1.34	1.4%
Non-Associated	3.83	3.74	3.38	3.64	3.31	3.56	-0.2%
Alaska	0.43	0.44	0.25	0.27	1.89	2.23	7.6%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	178.48	180.77	204.21	194.93	186.10	178.29	-0.1%
Supplemental Gas Supplies (trillion cubic feet)[5]	0.07	0.06	0.08	0.08	0.08	0.08	0.7%
Total Lower 48 Wells Drilled (thousands)	25.45	30.08	27.67	29.33	29.59	26.96	-0.5%

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]*Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).*
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.

Sources: 2002 and 2003 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). 2002 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2002) (Washington, DC, December 2003). 2002 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2002 natural gas lower 48 average wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004). 2003 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2002 and 2003 crude oil lower 48 average wellhead price: EIA, *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). Other 2002 and 2003 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Production[1]							
Appalachia	408	388	403	385	384	406	0.2%
Interior	147	146	159	157	164	182	1.0%
West	550	549	676	727	797	900	2.3%
East of the Mississippi	504	481	510	493	499	538	0.5%
West of the Mississippi	601	603	729	777	846	950	2.1%
Total	**1105**	**1083**	**1238**	**1270**	**1345**	**1488**	**1.5%**
Net Imports							
Imports	17	25	33	38	42	46	2.8%
Exports	40	43	42	35	35	26	-2.2%
Total	**-23**	**-18**	**-9**	**3**	**7**	**20**	**N/A**
Total Supply[2]	**1083**	**1065**	**1229**	**1273**	**1352**	**1507**	**1.6%**
Consumption by Sector							
Residential and Commercial	4	4	5	5	5	5	0.4%
Industrial[3]	63	62	66	66	66	66	0.3%
Coke Plants	22	24	20	18	15	13	-2.7%
Electric Power[4]	976	1004	1139	1185	1267	1425	1.6%
Total Sectoral Consumption	**1066**	**1095**	**1229**	**1273**	**1352**	**1508**	**1.5%**
Coal to Liquids							
Heat and Power (included in Industrial)	0	0	0	0	0	0	N/A
Liquids Production	0	0	0	0	0	0	N/A
Total Coal Use	**1066**	**1095**	**1229**	**1273**	**1352**	**1508**	**1.5%**
Discrepancy and Stock Change[5]	**17**	**-29**	**0**	**-0**	**-1**	**-1**	**N/A**
Average Minemouth Price							
(2003 dollars per short ton)	18.23	17.93	17.30	16.89	17.25	18.26	0.1%
(2003 dollars per million Btu)	0.89	0.86	0.85	0.84	0.86	0.91	0.2%
Delivered Prices (2003 dollars per short ton)[6]							
Industrial	36.08	34.74	33.80	33.44	33.77	34.60	-0.0%
Coke Plants	51.60	50.63	49.87	48.38	48.03	46.14	-0.4%
Electric Power							
(2003 dollars per short ton)	26.26	25.86	24.89	24.42	24.66	25.95	0.0%
(2003 dollars per million Btu)	1.27	1.28	1.25	1.23	1.25	1.31	0.1%
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average	**27.38**	**26.91**	**25.78**	**25.22**	**25.37**	**26.51**	**-0.1%**
Exports[7]	41.18	39.80	39.29	37.40	37.20	36.06	-0.4%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002 and 11.6 million tons in 2003.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential and commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002: Energy Information Administration (EIA), *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). 2003 data based on: EIA, *Annual Coal Report 2003*, DOE/EIA-0584(2003) (Washington, DC, September 2004); EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004); and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Electric Power Sector[1]							
Net Summer Capacity							
Conventional Hydropower	77.80	77.93	78.18	78.18	78.18	78.18	0.0%
Geothermal[2]	2.17	2.18	2.21	2.66	3.45	4.62	3.5%
Municipal Solid Waste[3]	3.26	3.34	3.57	3.63	3.66	3.67	0.4%
Wood and Other Biomass[4,5]	1.77	1.77	1.83	2.06	2.75	4.50	4.3%
Solar Thermal	0.39	0.39	0.45	0.47	0.49	0.51	1.3%
Solar Photovoltaic[6]	0.03	0.04	0.15	0.23	0.32	0.40	10.9%
Wind	5.01	6.56	8.88	9.29	10.45	11.25	2.5%
Total	**90.42**	**92.21**	**95.27**	**96.50**	**99.29**	**103.13**	**0.5%**
Generation (billion kilowatthours)							
Conventional Hydropower	260.67	269.29	300.39	300.55	300.81	301.09	0.5%
Geothermal[2]	14.49	13.15	12.33	16.09	22.83	32.78	4.2%
Municipal Solid Waste[3]	20.46	20.28	25.58	26.07	26.36	26.49	1.2%
Wood and Other Biomass[5]	9.74	9.40	27.61	30.01	32.35	37.35	6.5%
Dedicated Plants	7.06	5.73	10.32	11.67	16.21	27.29	7.4%
Cofiring	2.68	3.66	17.29	18.34	16.13	10.06	4.7%
Solar Thermal	0.55	0.53	0.80	0.86	0.92	0.99	2.9%
Solar Photovoltaic[6]	0.00	0.00	0.32	0.52	0.74	0.96	30.0%
Wind	10.35	10.73	25.89	27.34	31.61	34.52	5.5%
Total	**316.27**	**323.38**	**392.90**	**401.44**	**415.61**	**434.19**	**1.3%**
End-Use Sector[7]							
Net Summer Capacity							
Conventional Hydropower[8]	1.02	1.03	1.03	1.03	1.03	1.03	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	0.22	0.26	0.26	0.26	0.26	0.26	0.0%
Biomass	4.08	4.08	5.14	5.55	6.18	6.75	2.3%
Solar Photovoltaic[6]	0.04	0.06	0.39	0.44	0.80	1.80	17.0%
Total	**5.37**	**5.43**	**6.82**	**7.30**	**8.27**	**9.85**	**2.7%**
Generation (billion kilowatthours)							
Conventional Hydropower[8]	3.67	5.82	5.82	5.82	5.82	5.82	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	1.65	1.86	2.24	2.24	2.24	2.24	0.8%
Biomass	29.04	27.59	33.76	36.19	39.86	43.21	2.1%
Solar Photovoltaic[6]	0.09	0.12	0.83	0.95	1.68	3.74	16.9%
Total	**34.45**	**35.39**	**42.64**	**45.20**	**49.60**	**55.00**	**2.0%**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]*Includes projections for energy crops after 2010.*
[6]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2002, EIA estimates that as much as 134 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2002, plus an additional 362 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Annual Energy Review 2003, Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2002 and 2003 generation: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Marketed Renewable Energy[2]							
Residential (wood)	0.39	0.40	0.40	0.39	0.39	0.38	-0.3%
Commercial (biomass)	0.08	0.09	0.09	0.09	0.09	0.09	0.0%
Industrial[3]	1.78	1.79	2.07	2.19	2.34	2.50	1.5%
Conventional Hydroelectric	0.04	0.06	0.06	0.06	0.06	0.06	0.0%
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.0%
Biomass	1.73	1.72	1.99	2.12	2.27	2.42	1.6%
Transportation	0.17	0.24	0.32	0.33	0.36	0.38	2.2%
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Ethanol used in Gasoline Blending	0.17	0.24	0.32	0.33	0.35	0.38	2.2%
Electric Power[5]	3.54	3.62	4.30	4.46	4.75	5.14	1.6%
Conventional Hydroelectric	2.64	2.72	3.08	3.08	3.08	3.08	0.6%
Geothermal	0.30	0.28	0.27	0.39	0.61	0.92	5.6%
Municipal Solid Waste[6]	0.31	0.32	0.34	0.35	0.35	0.35	0.4%
Biomass	0.17	0.18	0.32	0.35	0.36	0.40	3.6%
Dedicated Plants	0.11	0.09	0.10	0.12	0.17	0.28	5.4%
Cofiring	0.06	0.09	0.22	0.23	0.19	0.11	0.9%
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	6.2%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.10	0.11	0.27	0.28	0.33	0.36	5.5%
Total Marketed Renewable Energy	5.96	6.13	7.17	7.46	7.93	8.48	1.5%
Sources of Ethanol							
From Corn	0.17	0.24	0.32	0.33	0.34	0.34	1.7%
From Cellulose	0.00	0.00	0.00	0.01	0.02	0.04	N/A
Total	0.17	0.24	0.32	0.33	0.36	0.38	2.2%
Non-Marketed Renewable Energy[7]							
Selected Consumption							
Residential	0.02	0.02	0.03	0.04	0.04	0.05	3.3%
Solar Hot Water Heating	0.02	0.02	0.03	0.03	0.03	0.04	2.4%
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.01	7.6%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	17.5%
Commercial	0.02	0.02	0.03	0.03	0.03	0.04	2.1%
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.7%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	16.7%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2002 and 2003 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2002 and 2003 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons)

Sector and Source	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Residential							
Petroleum	104.1	106.2	107.4	108.4	107.0	104.1	-0.1%
Natural Gas	265.9	277.3	300.2	311.7	319.4	325.6	0.7%
Coal	1.0	1.1	1.1	1.0	1.0	0.9	-1.0%
Electricity	823.7	840.3	946.5	998.0	1060.3	1149.4	1.4%
Total	**1194.7**	**1225.0**	**1355.2**	**1419.1**	**1487.6**	**1580.0**	**1.2%**
Commercial							
Petroleum	52.6	53.8	61.3	64.9	68.7	72.8	1.4%
Natural Gas	168.7	170.6	184.0	194.7	206.4	220.1	1.2%
Coal	8.6	9.4	9.2	9.2	9.1	9.1	-0.1%
Electricity	785.4	794.3	943.0	1040.3	1159.3	1325.8	2.4%
Total	**1015.4**	**1028.1**	**1197.6**	**1309.1**	**1443.5**	**1627.9**	**2.1%**
Industrial[1]							
Petroleum	412.5	421.8	466.7	476.1	503.6	520.7	1.0%
Natural Gas[2]	449.9	419.8	483.8	506.0	531.6	550.2	1.2%
Coal	183.9	186.1	189.5	181.9	176.2	171.1	-0.4%
Electricity	632.0	636.1	712.2	734.6	768.2	816.6	1.1%
Total	**1678.4**	**1663.8**	**1852.3**	**1898.7**	**1979.6**	**2058.6**	**1.0%**
Transportation							
Petroleum[3]	1810.6	1821.6	2165.0	2364.4	2540.2	2723.1	1.8%
Natural Gas[4]	37.1	35.4	40.0	42.9	48.7	50.4	1.6%
Electricity	14.4	14.9	16.9	18.2	19.9	22.3	1.8%
Total	**1862.1**	**1871.9**	**2221.8**	**2425.5**	**2608.9**	**2795.8**	**1.8%**
Electric Power[5]							
Petroleum	76.9	95.8	96.3	100.7	106.9	109.2	0.6%
Natural Gas	305.6	266.6	362.1	450.8	508.0	506.5	3.0%
Coal	1855.8	1906.0	2139.8	2218.8	2371.5	2676.8	1.6%
Other[6]	17.3	17.3	20.4	20.9	21.2	21.5	1.0%
Total	**2255.6**	**2285.7**	**2618.6**	**2791.1**	**3007.6**	**3314.1**	**1.7%**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	2456.7	2499.2	2896.7	3114.5	3326.5	3530.0	1.6%
Natural Gas	1227.1	1169.7	1370.2	1506.1	1614.0	1652.9	1.6%
Coal	2049.4	2102.5	2339.5	2410.9	2557.9	2857.9	1.4%
Other[6]	17.3	17.3	20.4	20.9	21.2	21.5	1.0%
Total	**5750.5**	**5788.7**	**6626.8**	**7052.4**	**7519.6**	**8062.3**	**1.5%**
Carbon Dioxide Emissions (ton per person)	**19.9**	**19.9**	**21.4**	**21.8**	**22.3**	**23.0**	**0.7%**

[1]Fuel consumption includes energy for combined heat and power plants (CHP), except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2002, international bunker fuels accounted for 82 to 100 million metric tons of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[6]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
[7]Emissions from the electric power sector are distributed to the primary fuels.
N/A = Not applicable
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2002 and 2003 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A19. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Real Gross Domestic Product	10075	10381	13084	15216	17634	20292	3.1%
Real Potential Gross Domestic Product	10396	10736	13464	15188	17491	20462	3.0%
Real Disposable Personal Income	7560	7734	9594	11192	12783	14990	3.1%
Components of Real Gross Domestic Product							
Real Consumption	7123	7356	9031	10389	11826	13352	2.7%
Real Investment	1561	1629	2324	2977	3805	4868	5.1%
Real Government Spending	1858	1909	2135	2302	2486	2647	1.5%
Real Exports	1012	1032	1917	2640	3633	4956	7.4%
Real Imports	1484	1550	2287	2991	3883	5094	5.6%
Energy Intensity (thousand Btu per 2000 dollar of GDP)							
Delivered Energy	7.11	6.92	6.23	5.70	5.23	4.81	-1.6%
Total Energy	9.73	9.47	8.51	7.78	7.13	6.57	-1.6%
Price Indices							
GDP Chain-Type Price Index (2000=1.000)	1.041	1.060	1.218	1.373	1.563	1.814	2.5%
Consumer Price Index (1982-4=1)	1.80	1.84	2.12	2.41	2.78	3.26	2.6%
Wholesale Price Index (1982=1.00)							
All Commodities	1.31	1.38	1.50	1.61	1.74	1.91	1.5%
Fuel and Power	0.93	1.13	1.13	1.35	1.61	1.93	2.5%
Interest Rates (percent, nominal)							
Federal Funds Rate	1.67	1.13	5.51	5.56	5.52	5.91	N/A
10-Year Treasury Note	4.61	4.01	6.61	6.47	6.43	6.57	N/A
AA Utility Bond Rate	7.19	6.39	7.66	8.07	8.34	8.59	N/A
Unemployment Rate (percent)	5.78	5.99	5.57	4.89	4.48	4.55	N/A
Housing Starts (millions)	1.88	1.98	1.89	1.89	1.88	1.89	-0.2%
Commercial Floorspace, Total (billion square feet)	70.9	72.1	81.2	88.4	96.2	104.8	1.7%
Unit Sales of Light-Duty Vehicles (millions)	16.78	16.63	18.06	18.49	19.66	21.11	1.1%
Value of Shipments (billion 1996 dollars)							
Total Industrial	5067	5105	6165	6850	7633	8469	2.3%
Non-manufacturing	1240	1254	1329	1458	1587	1736	1.5%
Manufacturing	3826	3851	4836	5392	6046	6733	2.6%
Energy-Intensive	1057	1048	1219	1298	1384	1462	1.5%
Non-Energy Intensive	2769	2803	3617	4094	4662	5271	2.9%
Population and Employment (millions)							
Population, with Armed Forces Overseas	288.6	291.4	310.1	323.5	337.0	350.6	0.8%
Population, aged 16 and over	223.9	226.5	244.1	254.5	265.3	276.5	0.9%
Employment, Nonfarm	130.3	129.9	140.7	148.8	159.7	169.1	1.2%
Employment, Manufacturing	15.3	14.5	14.0	13.3	13.0	12.7	-0.6%
Labor Force	145.1	146.5	159.3	163.4	169.8	176.8	0.9%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 2002 and 2003: Global Insight macroeconomic model CTL0804, modified by Energy Information Administration (EIA); and Global Insight industry model, August 2004. **Projections:** EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Table A20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
World Oil Price (2003 dollars per barrel)[1]	**24.10**	**27.73**	**25.00**	**26.75**	**28.50**	**30.31**	**0.4%**
Production (Conventional)[2]							
Industrialized Countries							
U.S. (50 states)	9.27	9.09	9.61	9.27	9.21	8.82	-0.1%
Canada	2.14	2.25	1.83	1.64	1.60	1.57	-1.6%
Mexico	3.61	3.80	4.21	4.55	4.62	4.85	1.1%
Western Europe[3]	6.87	6.69	6.35	5.89	5.51	5.00	-1.3%
Japan	0.20	0.13	0.08	0.07	0.06	0.06	-3.3%
Australia and New Zealand	0.75	0.66	0.96	0.91	0.89	0.86	1.2%
Total Industrialized	**22.85**	**22.62**	**23.05**	**22.33**	**21.89**	**21.16**	**-0.3%**
Eurasia							
Former Soviet Union							
Russia	7.67	8.34	9.98	10.62	10.90	11.11	1.3%
Caspian Area[4]	1.66	1.87	3.14	4.46	5.23	6.22	5.6%
Eastern Europe[5]	0.17	0.22	0.33	0.38	0.41	0.45	3.2%
Total Eurasia	**9.50**	**10.44**	**13.46**	**15.46**	**16.54**	**17.78**	**2.5%**
Developing Countries							
OPEC[6]							
Asia	1.39	1.38	1.47	1.47	1.51	1.56	0.6%
Middle East	20.90	20.95	24.45	26.87	32.37	38.47	2.8%
North Africa	3.03	2.99	3.44	3.71	4.44	4.78	2.2%
West Africa	2.01	1.98	2.36	2.64	3.13	3.74	2.9%
South America	2.91	2.85	3.34	3.81	4.44	5.20	2.8%
Non-OPEC							
China	2.99	3.10	3.64	3.50	3.49	3.41	0.4%
Other Asia	2.38	2.59	2.65	2.76	2.71	2.64	0.1%
Middle East[7]	1.91	1.81	2.24	2.47	2.57	2.78	2.0%
Africa	2.89	2.94	3.75	4.75	5.44	6.56	3.7%
South and Central America	3.79	3.93	4.53	5.38	5.91	6.42	2.3%
Total Developing Countries	**44.20**	**44.52**	**51.87**	**57.35**	**66.02**	**75.57**	**2.4%**
Total Production (Conventional)	**76.55**	**77.58**	**88.38**	**95.14**	**104.45**	**114.51**	**1.8%**
Production (Nonconventional)[8]							
U.S. (50 states)	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Other North America	0.81	0.93	1.73	3.09	3.33	3.46	6.2%
Western Europe	0.04	0.04	0.04	0.05	0.05	0.05	1.8%
Asia	0.03	0.03	0.04	0.04	0.05	0.07	4.4%
Middle East[7]	0.01	0.03	0.12	0.16	0.21	0.25	10.8%
Africa	0.20	0.21	0.23	0.25	0.28	0.32	2.0%
South and Central America	0.54	0.57	0.82	1.36	1.48	1.50	4.5%
Total Production (Nonconventional)	**1.63**	**1.79**	**2.98**	**4.94**	**5.40**	**5.65**	**5.4%**
Total Production	**78.18**	**79.37**	**91.35**	**100.08**	**109.85**	**120.17**	**1.9%**

Table A20. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 2003-2025 (percent)
	2002	2003	2010	2015	2020	2025	
Consumption[9]							
Industrialized Countries							
U.S. (50 states)	19.71	20.00	22.98	24.67	26.32	27.93	1.5%
U.S. Territories	0.32	0.36	0.38	0.40	0.43	0.47	1.2%
Canada	2.09	2.17	2.30	2.46	2.62	2.80	1.2%
Mexico	1.98	2.02	2.36	2.63	2.88	3.48	2.5%
Western Europe[3]	13.81	14.22	14.72	15.08	15.45	15.71	0.5%
Japan	5.30	5.58	5.70	5.72	5.69	5.84	0.2%
Australia and New Zealand	1.01	1.04	1.27	1.40	1.54	1.69	2.2%
Total Industrialized	**44.23**	**45.38**	**49.72**	**52.36**	**54.93**	**57.92**	**1.1%**
Eurasia							
Former Soviet Union	4.11	4.18	4.39	5.02	5.74	6.45	2.0%
Eastern Europe[5]	1.41	1.42	1.56	1.68	1.89	2.09	1.8%
Total Eurasia	**5.52**	**5.59**	**5.95**	**6.70**	**7.63**	**8.54**	**1.9%**
Developing Countries							
China	5.16	5.54	7.63	9.20	11.06	12.79	3.9%
India	2.18	2.19	2.79	3.48	4.37	5.29	4.1%
South Korea	2.18	2.17	2.51	2.65	2.75	2.93	1.4%
Other Asia	5.59	5.74	7.28	8.36	9.47	10.66	2.9%
Middle East[7]	5.68	5.58	6.83	7.53	8.34	9.08	2.2%
Africa	2.67	2.72	3.13	3.57	4.13	4.66	2.5%
South and Central America	4.88	4.69	5.81	6.53	7.48	8.61	2.8%
Total Developing Countries	**28.35**	**28.64**	**35.98**	**41.31**	**47.59**	**54.01**	**2.9%**
Total Consumption	**78.10**	**79.60**	**91.65**	**100.38**	**110.14**	**120.47**	**1.9%**
OPEC Production[10]	30.65	30.60	35.79	39.67	47.21	55.13	2.7%
Non-OPEC Production[10]	47.52	48.77	55.56	60.41	62.64	65.04	1.3%
Net Eurasia Exports	3.99	4.84	7.51	8.75	8.92	9.25	3.0%
OPEC Market Share	0.39	0.39	0.39	0.40	0.43	0.46	0.8%

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2002 data derived from: Energy Information Administration (EIA), *International Energy Annual 2002*, DOE/EIA-0219(2002) (Washington, DC, March 2004).
2003 and projections: EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

Economic Growth Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	12.03	12.74	12.75	12.78	10.99	11.03	11.07	9.96	10.01	10.19
Natural Gas Plant Liquids	2.34	2.66	2.66	2.70	2.69	2.80	2.86	2.75	2.81	2.83
Dry Natural Gas	19.58	20.90	20.97	21.39	21.34	22.48	23.11	21.94	22.42	22.65
Coal	22.66	24.73	25.10	25.43	26.05	27.04	28.15	27.51	29.90	32.20
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.73	6.85	6.95	7.27	7.57	8.02	7.68	8.10	8.84
Other[2]	0.93	0.92	0.97	1.09	0.71	0.77	0.95	0.78	0.82	0.98
Total	**71.42**	**77.18**	**77.79**	**78.84**	**77.71**	**80.35**	**82.82**	**79.29**	**82.73**	**86.35**
Imports										
Crude Oil[3]	21.08	24.02	24.69	24.97	30.89	32.29	32.16	32.85	35.16	36.52
Petroleum Products[4]	5.16	5.25	6.06	7.19	5.44	6.83	9.75	6.65	8.27	10.69
Natural Gas	4.02	5.08	5.71	6.14	8.57	8.95	9.52	8.86	9.70	10.44
Other Imports[5]	0.69	0.90	0.92	0.96	1.12	1.15	1.17	1.21	1.23	1.25
Total	**30.95**	**35.25**	**37.38**	**39.27**	**46.02**	**49.22**	**52.60**	**49.58**	**54.36**	**58.90**
Exports										
Petroleum[6]	2.13	2.10	2.14	2.19	2.19	2.26	2.34	2.22	2.32	2.42
Natural Gas	0.70	0.67	0.65	0.64	0.91	0.86	0.81	0.91	0.83	0.73
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.88	0.67	0.65	0.65
Total	**3.95**	**3.83**	**3.86**	**3.89**	**3.99**	**4.01**	**4.02**	**3.80**	**3.80**	**3.80**
Discrepancy[7]	**0.18**	**0.03**	**0.05**	**0.03**	**0.02**	**-0.05**	**-0.09**	**0.14**	**0.10**	**0.10**
Consumption										
Petroleum Products[8]	39.09	43.37	44.84	46.42	48.29	51.30	54.31	50.43	54.42	58.44
Natural Gas	22.54	25.39	26.11	26.97	29.17	30.73	32.00	30.06	31.47	32.55
Coal	22.71	24.58	24.95	25.30	26.27	27.27	28.42	28.05	30.48	32.81
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.73	6.85	6.95	7.27	7.57	8.02	7.68	8.10	8.85
Other[9]	0.02	0.02	0.03	0.06	0.04	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**108.58**	**111.27**	**114.19**	**119.71**	**125.60**	**131.48**	**124.93**	**133.18**	**141.35**
Net Imports - Petroleum	**24.10**	**27.17**	**28.61**	**29.98**	**34.14**	**36.87**	**39.57**	**37.28**	**41.11**	**44.79**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[10]	27.73	24.45	25.00	25.61	27.40	28.50	29.71	28.75	30.31	31.99
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.48	3.64	3.89	4.19	4.53	4.88	4.53	4.79	5.16
Coal Minemouth Price (dollars per ton)	17.93	17.17	17.30	17.70	16.79	17.25	17.89	17.11	18.26	19.78
Average Electricity Price (cents per kilowatthour)	7.4	6.4	6.6	6.9	6.9	7.2	7.5	7.0	7.3	7.6

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Energy Consumption										
Residential										
Distillate Fuel	0.96	0.90	0.90	0.90	0.83	0.83	0.83	0.77	0.77	0.77
Kerosene	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.08
Liquefied Petroleum Gas	0.54	0.57	0.57	0.57	0.63	0.64	0.65	0.65	0.67	0.67
Petroleum Subtotal	1.58	1.56	1.56	1.56	1.55	1.56	1.57	1.51	1.53	1.53
Natural Gas	5.25	5.68	5.68	5.69	5.90	6.05	6.13	5.96	6.17	6.28
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.40	0.40	0.38	0.39	0.39	0.37	0.38	0.39
Electricity	4.37	5.01	5.02	5.03	5.66	5.79	5.88	5.96	6.18	6.31
Delivered Energy	**11.61**	**12.67**	**12.67**	**12.69**	**13.51**	**13.80**	**13.98**	**13.81**	**14.26**	**14.52**
Electricity Related Losses	9.71	10.83	10.80	10.77	11.71	11.77	11.80	12.12	12.35	12.42
Total	**21.31**	**23.49**	**23.47**	**23.47**	**25.22**	**25.56**	**25.79**	**25.93**	**26.62**	**26.94**
Commercial										
Distillate Fuel	0.52	0.61	0.62	0.62	0.70	0.71	0.72	0.74	0.77	0.78
Residual Fuel	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.85	0.86	0.86	0.95	0.96	0.97	0.99	1.02	1.04
Natural Gas	3.22	3.47	3.49	3.49	3.80	3.91	4.01	4.01	4.17	4.32
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	4.97	5.00	5.02	6.17	6.33	6.48	6.87	7.12	7.37
Delivered Energy	**8.29**	**9.47**	**9.53**	**9.55**	**11.09**	**11.38**	**11.64**	**12.05**	**12.49**	**12.91**
Electricity Related Losses	9.18	10.73	10.76	10.73	12.75	12.86	13.00	13.97	14.25	14.50
Total	**17.46**	**20.20**	**20.29**	**20.28**	**23.84**	**24.24**	**24.64**	**26.02**	**26.74**	**27.41**
Industrial[4]										
Distillate Fuel	1.03	0.97	1.04	1.12	1.02	1.14	1.26	1.05	1.19	1.34
Liquefied Petroleum Gas	2.09	2.14	2.30	2.48	2.27	2.59	2.94	2.31	2.74	3.22
Petrochemical Feedstock	1.32	1.38	1.48	1.59	1.37	1.55	1.76	1.33	1.57	1.86
Residual Fuel	0.28	0.32	0.34	0.37	0.37	0.38	0.40	0.37	0.38	0.44
Motor Gasoline[2]	0.31	0.29	0.31	0.34	0.30	0.35	0.39	0.32	0.37	0.43
Other Petroleum[5]	4.30	4.41	4.69	4.97	4.51	5.02	5.36	4.62	5.23	5.63
Petroleum Subtotal	9.31	9.51	10.17	10.87	9.85	11.03	12.11	10.00	11.47	12.92
Natural Gas	7.19	7.79	8.10	8.50	8.24	8.89	9.68	8.33	9.26	10.31
Lease and Plant Fuel[6]	1.15	1.20	1.20	1.22	1.27	1.32	1.36	1.28	1.31	1.32
Natural Gas Subtotal	8.34	8.99	9.31	9.72	9.51	10.21	11.04	9.61	10.57	11.63
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.36	0.37	0.37
Steam Coal	1.39	1.40	1.42	1.46	1.38	1.42	1.46	1.36	1.42	1.47
Net Coal Coke Imports	0.05	0.05	0.06	0.07	0.04	0.05	0.07	0.03	0.05	0.07
Coal Subtotal	2.11	1.99	2.03	2.08	1.83	1.89	1.95	1.76	1.83	1.91
Renewable Energy[7]	1.79	1.97	2.07	2.17	2.13	2.34	2.60	2.21	2.50	2.84
Electricity	3.31	3.54	3.78	4.04	3.77	4.19	4.64	3.82	4.39	5.02
Delivered Energy	**24.86**	**26.00**	**27.35**	**28.88**	**27.10**	**29.66**	**32.34**	**27.40**	**30.76**	**34.32**
Electricity Related Losses	7.35	7.65	8.13	8.65	7.79	8.52	9.31	7.76	8.78	9.88
Total	**32.21**	**33.65**	**35.47**	**37.54**	**34.89**	**38.19**	**41.65**	**35.16**	**39.53**	**44.20**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Distillate Fuel[8]	5.54	6.54	6.95	7.38	7.55	8.35	9.14	8.04	9.05	10.19
Jet Fuel[9]	3.26	3.97	4.04	4.08	4.73	4.74	4.72	4.87	4.89	4.91
Motor Gasoline[2]	16.64	18.85	19.14	19.47	21.36	22.31	23.26	22.69	24.04	25.32
Residual Fuel	0.62	0.56	0.56	0.57	0.57	0.58	0.58	0.57	0.58	0.59
Liquefied Petroleum Gas	0.02	0.05	0.06	0.06	0.07	0.08	0.08	0.08	0.09	0.09
Other Petroleum[10]	0.24	0.24	0.26	0.27	0.27	0.29	0.32	0.28	0.31	0.35
Petroleum Subtotal	26.31	30.21	31.00	31.84	34.55	36.35	38.11	36.53	38.97	41.46
Pipeline Fuel Natural Gas	0.65	0.69	0.70	0.72	0.79	0.82	0.85	0.83	0.84	0.85
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.10	0.11	0.10	0.11	0.12
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**27.07**	**31.05**	**31.85**	**32.71**	**35.54**	**37.39**	**39.18**	**37.58**	**40.04**	**42.56**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.24
Total	**27.24**	**31.24**	**32.04**	**32.90**	**35.77**	**37.61**	**39.40**	**37.82**	**40.28**	**42.80**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.04	9.03	9.51	10.01	10.11	11.03	11.95	10.61	11.78	13.09
Kerosene	0.11	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13
Jet Fuel[9]	3.26	3.97	4.04	4.08	4.73	4.74	4.72	4.87	4.89	4.91
Liquefied Petroleum Gas	2.75	2.87	3.03	3.21	3.08	3.42	3.78	3.15	3.60	4.09
Motor Gasoline[2]	16.98	19.18	19.49	19.86	21.71	22.70	23.70	23.04	24.45	25.79
Petrochemical Feedstock	1.32	1.38	1.48	1.59	1.37	1.55	1.76	1.33	1.57	1.86
Residual Fuel	0.97	0.95	0.97	1.02	1.01	1.03	1.06	1.02	1.03	1.11
Other Petroleum[12]	4.52	4.63	4.93	5.22	4.76	5.30	5.66	4.88	5.53	5.97
Petroleum Subtotal	37.96	42.14	43.58	45.12	46.91	49.90	52.76	49.03	52.98	56.94
Natural Gas	15.68	16.99	17.33	17.75	18.03	18.94	19.93	18.39	19.70	21.03
Lease and Plant Fuel Plant[6]	1.15	1.20	1.20	1.22	1.27	1.32	1.36	1.28	1.31	1.32
Pipeline Natural Gas	0.65	0.69	0.70	0.72	0.79	0.82	0.85	0.83	0.84	0.85
Natural Gas Subtotal	17.48	18.88	19.23	19.69	20.09	21.09	22.14	20.50	21.85	23.20
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.36	0.37	0.37
Steam Coal	1.50	1.50	1.53	1.56	1.48	1.52	1.57	1.47	1.52	1.58
Net Coal Coke Imports	0.05	0.05	0.06	0.07	0.04	0.05	0.07	0.03	0.05	0.07
Coal Subtotal	2.22	2.10	2.14	2.19	1.94	2.00	2.06	1.86	1.94	2.02
Renewable Energy[13]	2.28	2.46	2.55	2.66	2.61	2.82	3.08	2.67	2.97	3.32
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.62	13.89	14.18	15.70	16.41	17.10	16.77	17.81	18.83
Delivered Energy	**71.82**	**79.19**	**81.39**	**83.83**	**87.24**	**92.23**	**97.14**	**90.84**	**97.56**	**104.31**
Electricity Related Losses	26.40	29.39	29.88	30.35	32.47	33.37	34.34	34.09	35.62	37.05
Total	**98.22**	**108.58**	**111.27**	**114.19**	**119.71**	**125.60**	**131.48**	**124.93**	**133.18**	**141.35**
Electric Power[14]										
Distillate Fuel	0.33	0.38	0.39	0.40	0.49	0.42	0.53	0.43	0.45	0.51
Residual Fuel	0.80	0.85	0.87	0.90	0.89	0.98	1.02	0.97	0.98	1.00
Petroleum Subtotal	1.13	1.23	1.26	1.30	1.39	1.40	1.55	1.40	1.43	1.51
Natural Gas	5.06	6.51	6.87	7.28	9.08	9.64	9.86	9.56	9.61	9.34
Steam Coal	20.49	22.48	22.81	23.11	24.34	25.28	26.36	26.19	28.54	30.79
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[15]	3.62	4.27	4.30	4.30	4.67	4.75	4.94	5.01	5.14	5.53
Electricity Imports	0.02	0.02	0.03	0.06	0.04	0.05	0.06	0.04	0.04	0.04
Total	**38.28**	**43.01**	**43.77**	**44.54**	**48.17**	**49.79**	**51.44**	**50.86**	**53.43**	**55.87**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Distillate Fuel	8.37	9.41	9.90	10.42	10.60	11.45	12.48	11.04	12.23	13.60
Kerosene	0.11	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13
Jet Fuel[9]	3.26	3.97	4.04	4.08	4.73	4.74	4.72	4.87	4.89	4.91
Liquefied Petroleum Gas	2.75	2.87	3.03	3.21	3.08	3.42	3.78	3.15	3.60	4.09
Motor Gasoline[2]	16.98	19.18	19.49	19.86	21.71	22.70	23.70	23.04	24.45	25.79
Petrochemical Feedstock	1.32	1.38	1.48	1.59	1.37	1.55	1.76	1.33	1.57	1.86
Residual Fuel	1.77	1.80	1.84	1.91	1.90	2.01	2.08	1.99	2.02	2.11
Other Petroleum[12]	4.52	4.63	4.93	5.22	4.76	5.30	5.66	4.88	5.53	5.97
Petroleum Subtotal	39.09	43.37	44.84	46.42	48.29	51.30	54.31	50.43	54.42	58.44
Natural Gas	20.74	23.50	24.21	25.03	27.11	28.59	29.79	27.96	29.32	30.38
Lease and Plant Fuel[6]	1.15	1.20	1.20	1.22	1.27	1.32	1.36	1.28	1.31	1.32
Pipeline Natural Gas	0.65	0.69	0.70	0.72	0.79	0.82	0.85	0.83	0.84	0.85
Natural Gas Subtotal	22.54	25.39	26.11	26.97	29.17	30.73	32.00	30.06	31.47	32.55
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.36	0.37	0.37
Steam Coal	21.99	23.98	24.34	24.68	25.82	26.80	27.93	27.66	30.07	32.37
Net Coal Coke Imports	0.05	0.05	0.06	0.07	0.04	0.05	0.07	0.03	0.05	0.07
Coal Subtotal	22.71	24.58	24.95	25.30	26.27	27.27	28.42	28.05	30.48	32.81
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[16]	5.89	6.73	6.85	6.95	7.27	7.57	8.02	7.68	8.10	8.85
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.02	0.03	0.06	0.04	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**108.58**	**111.27**	**114.19**	**119.71**	**125.60**	**131.48**	**124.93**	**133.18**	**141.35**
Energy Use and Related Statistics										
Delivered Energy Use	71.82	79.19	81.39	83.83	87.24	92.23	97.14	90.84	97.56	104.31
Total Energy Use	98.22	108.58	111.27	114.19	119.71	125.60	131.48	124.93	133.18	141.35
Population (millions)	291.39	305.62	310.12	314.61	325.13	336.99	348.84	334.92	350.64	366.35
Gross Domestic Product (billion 2000 dollars)	10381	12640	13084	13740	16163	17634	19089	17957	20292	22570
Carbon Dioxide Emissions										
Carbon Dioxide Emissions (million metric tons)	5788.7	6472.5	6626.8	6782.8	7170.9	7519.6	7856.1	7529.7	8062.3	8560.8

[1]Includes wood used for residential heating. See Table B4 and/or Table B17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

Table B3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**15.81**	**13.88**	**14.33**	**14.89**	**14.98**	**15.64**	**16.37**	**15.51**	**16.13**	**16.93**
Primary Energy[1]	9.68	8.15	8.35	8.63	8.84	9.21	9.62	9.28	9.62	10.08
Petroleum Products[2]	11.27	10.15	10.44	10.71	10.90	11.36	11.84	11.44	11.93	12.41
Distillate Fuel	9.57	8.05	8.29	8.43	8.44	8.85	9.17	8.82	9.12	9.43
Liquefied Petroleum Gas	14.58	13.88	14.25	14.73	14.61	15.06	15.71	14.98	15.65	16.25
Natural Gas	9.22	7.61	7.79	8.07	8.31	8.66	9.06	8.75	9.07	9.53
Electricity	25.42	22.18	22.96	23.93	23.09	24.12	25.22	23.31	24.24	25.42
Commercial	**15.63**	**13.28**	**13.76**	**14.45**	**14.95**	**15.70**	**16.52**	**15.52**	**16.20**	**17.08**
Primary Energy[1]	7.92	6.63	6.81	7.07	7.21	7.54	7.89	7.53	7.82	8.22
Petroleum Products[2]	8.03	6.89	7.13	7.43	7.15	7.55	7.90	7.52	7.84	8.15
Distillate Fuel	7.03	6.06	6.30	6.59	6.34	6.76	7.09	6.77	7.06	7.35
Residual Fuel	4.96	4.17	4.26	4.35	4.62	4.81	4.99	4.85	5.08	5.33
Natural Gas	8.08	6.70	6.87	7.13	7.36	7.68	8.04	7.67	7.96	8.37
Electricity	23.24	19.19	19.93	21.00	21.03	22.10	23.28	21.44	22.40	23.65
Industrial[3]	**7.78**	**6.54**	**6.85**	**7.23**	**7.25**	**7.75**	**8.27**	**7.55**	**8.13**	**8.67**
Primary Energy	6.49	5.31	5.55	5.84	5.86	6.27	6.68	6.14	6.64	7.07
Petroleum Products[2]	8.29	6.98	7.24	7.54	7.44	7.88	8.34	7.75	8.36	8.77
Distillate Fuel	7.24	6.56	6.78	7.11	6.95	7.37	7.67	7.47	7.73	7.99
Liquefied Petroleum Gas	12.57	9.64	10.02	10.51	10.18	10.74	11.38	10.47	11.35	11.98
Residual Fuel	4.59	3.80	3.87	3.93	4.16	4.34	4.53	4.37	4.62	4.87
Natural Gas[4]	5.56	4.19	4.37	4.65	4.91	5.23	5.60	5.15	5.47	5.89
Metallurgical Coal	1.85	1.80	1.82	1.84	1.73	1.75	1.77	1.67	1.68	1.70
Steam Coal	1.55	1.54	1.56	1.59	1.53	1.56	1.60	1.54	1.60	1.69
Electricity	15.03	13.27	13.84	14.62	14.60	15.47	16.39	14.98	15.75	16.69
Transportation	**11.46**	**10.56**	**10.95**	**11.31**	**10.73**	**11.16**	**11.59**	**11.04**	**11.46**	**11.93**
Primary Energy	11.43	10.54	10.93	11.28	10.71	11.13	11.56	11.01	11.44	11.90
Petroleum Products[2]	11.43	10.54	10.93	11.29	10.71	11.13	11.57	11.02	11.44	11.91
Distillate Fuel[5]	10.92	10.43	10.76	11.28	10.12	10.66	11.08	10.48	10.85	11.27
Jet Fuel[6]	6.46	5.98	6.25	6.47	6.19	6.58	7.00	6.51	6.93	7.22
Motor Gasoline[7]	12.93	11.86	12.32	12.66	12.16	12.52	12.93	12.41	12.81	13.30
Residual Fuel	4.49	3.65	3.74	3.83	4.11	4.28	4.47	4.32	4.56	4.83
Liquefied Petroleum Gas[8]	16.65	14.86	15.24	15.75	15.11	15.66	16.39	15.31	16.24	17.00
Natural Gas[9]	9.04	8.31	8.56	8.88	9.07	9.45	9.89	9.35	9.69	10.20
Ethanol (E85)[10]	16.23	16.70	17.11	17.28	17.48	17.22	17.65	18.00	18.13	18.13
Electricity	20.64	18.13	18.81	19.68	19.07	19.99	20.94	19.20	19.96	20.93
Average End-Use Energy	**11.50**	**10.22**	**10.56**	**10.93**	**10.97**	**11.42**	**11.89**	**11.39**	**11.83**	**12.32**
Primary Energy	9.32	8.33	8.61	8.91	8.80	9.18	9.57	9.16	9.55	9.96
Electricity	21.74	18.74	19.36	20.21	20.21	21.11	22.06	20.62	21.38	22.37
Electric Power[11]										
Fossil Fuel Average	2.24	1.98	2.06	2.17	2.31	2.45	2.56	2.39	2.46	2.54
Petroleum Products	5.28	4.43	4.55	4.68	4.89	5.10	5.40	5.12	5.42	5.73
Distillate Fuel	6.48	5.14	5.36	5.57	5.55	6.01	6.34	5.99	6.33	6.63
Residual Fuel	4.79	4.11	4.19	4.27	4.52	4.71	4.90	4.75	5.00	5.27
Natural Gas	5.46	4.08	4.27	4.55	4.87	5.20	5.55	5.15	5.44	5.82
Steam Coal	1.28	1.23	1.25	1.28	1.21	1.25	1.28	1.24	1.31	1.39

Table B3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[12]										
Petroleum Products[2]	10.51	9.58	9.91	10.22	9.89	10.29	10.69	10.23	10.66	11.07
Distillate Fuel	9.90	9.21	9.53	9.98	9.22	9.79	10.17	9.65	10.03	10.45
Jet Fuel	6.46	5.98	6.25	6.47	6.19	6.58	7.00	6.51	6.93	7.22
Liquefied Petroleum Gas	13.04	10.66	10.99	11.43	11.29	11.74	12.30	11.61	12.34	12.86
Motor Gasoline[7]	12.93	11.85	12.31	12.64	12.15	12.51	12.92	12.40	12.80	13.29
Residual Fuel	4.66	3.92	3.99	4.08	4.33	4.52	4.71	4.56	4.81	5.06
Natural Gas	6.86	5.37	5.52	5.75	5.99	6.30	6.64	6.29	6.59	6.99
Coal	1.30	1.25	1.27	1.30	1.23	1.27	1.30	1.25	1.32	1.41
Ethanol (E85)[10]	16.23	16.70	17.11	17.28	17.48	17.22	17.65	18.00	18.13	18.13
Electricity	21.74	18.74	19.36	20.21	20.21	21.11	22.06	20.62	21.38	22.37
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)										
Residential	177.17	170.34	175.88	183.12	196.72	209.76	222.43	208.36	223.86	239.28
Commercial	128.15	124.66	129.92	136.76	164.55	177.28	190.81	185.66	200.93	219.13
Industrial	147.11	125.25	139.57	157.62	143.07	169.93	201.82	150.46	184.96	225.20
Transportation	302.59	320.52	341.13	361.71	372.99	407.83	444.15	405.66	449.31	497.43
Total Non-Renewable Expenditures	755.02	740.77	786.50	839.21	877.32	964.80	1059.21	950.14	1059.05	1181.04
Transportation Renewable Expenditures	0.02	0.03	0.03	0.04	0.06	0.07	0.07	0.07	0.08	0.09
Total Expenditures	**755.04**	**740.80**	**786.54**	**839.25**	**877.38**	**964.87**	**1059.28**	**950.21**	**1059.13**	**1181.14**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2003	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Real Gross Domestic Product	10381	12640	13084	13740	16163	17634	19089	17957	20292	22570
Real Potential Gross Domestic Product	10736	13176	13464	13858	16343	17491	18909	18530	20462	22637
Real Disposable Personal Income	7734	9314	9594	9946	11938	12783	13627	13698	14990	16237
Components of Real Gross Domestic Product										
Real Consumption	7356	8774	9031	9379	10894	11826	12531	11899	13352	14485
Real Investment	1629	2162	2324	2561	3268	3805	4257	3861	4868	5685
Real Government Spending	1909	2055	2135	2180	2285	2486	2613	2379	2647	2832
Real Exports	1032	1874	1917	1976	3336	3633	3947	4361	4956	5555
Real Imports	1550	2140	2287	2454	3550	3883	4365	4657	5094	5834
Energy Intensity (thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.92	6.27	6.23	6.11	5.40	5.23	5.09	5.06	4.81	4.63
Total Energy	9.47	8.60	8.51	8.31	7.41	7.13	6.89	6.96	6.57	6.27
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.060	1.295	1.218	1.142	1.736	1.563	1.394	2.077	1.814	1.556
Consumer Price Index (1982-4=1)	1.84	2.20	2.12	1.99	3.16	2.78	2.47	3.87	3.26	2.78
Wholesale Price Index (1982=1.00)										
All Commodities	1.38	1.57	1.50	1.41	2.01	1.74	1.54	2.33	1.91	1.62
Fuel and Power	1.13	1.16	1.13	1.11	1.70	1.61	1.51	2.12	1.93	1.75
Interest Rates (percent, nominal)										
Federal Funds Rate	1.13	5.88	5.51	5.15	5.99	5.52	5.01	6.57	5.91	5.28
10-Year Treasury Note	4.01	6.86	6.61	6.35	6.92	6.43	5.93	7.29	6.57	5.88
AA Utility Bond Rate	6.39	7.96	7.66	7.35	9.07	8.34	7.61	9.66	8.59	7.57
Unemployment Rate (percent)	5.99	6.17	5.57	4.97	5.13	4.48	3.86	5.27	4.55	3.84
Housing Starts (millions)	1.98	1.70	1.89	2.17	1.55	1.88	2.08	1.47	1.89	2.16
Commercial Floorspace, Total (billion square feet)	72.1	80.2	81.2	82.2	92.7	96.2	99.7	99.8	104.8	109.8
Unit Sales of Light-Duty Vehicles (millions)	16.63	17.02	18.06	19.37	17.98	19.66	21.47	18.54	21.11	23.78
Value of Shipments (billion 1996 dollars)										
Total Industrial	5105	5659	6165	6749	6626	7633	8692	7103	8469	9925
Non-manufacturing	1254	1163	1329	1528	1305	1587	1864	1414	1736	2077
Manufacturing	3851	4496	4836	5220	5322	6046	6827	5689	6733	7847
Energy-Intensive	1048	1164	1219	1273	1276	1384	1501	1313	1462	1627
Non-Energy Intensive	2803	3332	3617	3948	4046	4662	5326	4375	5271	6220
Population and Employment (millions)										
Population with Armed Forces Overseas	291.4	305.6	310.1	314.6	325.1	337.0	348.8	334.9	350.6	366.4
Population (aged 16 and over)	226.5	240.8	244.1	247.5	256.7	265.3	273.8	264.9	276.5	288.1
Employment,Non-Agriculture	129.9	134.3	140.7	147.5	148.4	159.7	169.9	155.6	169.1	183.6
Employment, Manufacturing	14.5	13.4	14.0	14.6	12.3	13.0	13.6	11.8	12.7	13.6
Labor Force	146.5	156.7	159.3	162.6	163.1	169.8	176.8	167.5	176.8	186.4

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2003: Global Insight macroeconomic model CTL0804, modified by Energy Information Administration (EIA); and Global Insight industry model, August 2004. **Projections:** EIA, AEO2005 National Energy Modeling System runs LM2005.D102004A, AEO2005.D102004A, and HM2005.D102004A.

Low and High A Oil Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Production										
Crude Oil and Lease Condensate	12.03	12.67	12.75	13.04	10.54	11.03	11.60	9.44	10.01	10.97
Natural Gas Plant Liquids	2.34	2.67	2.66	2.69	2.76	2.80	2.91	2.73	2.81	2.92
Dry Natural Gas	19.58	21.05	20.97	21.23	22.11	22.48	23.59	21.73	22.42	23.42
Coal	22.66	25.10	25.10	25.09	26.68	27.04	27.37	29.20	29.90	30.60
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.55	7.57	7.59	8.14	8.10	8.13
Other[2]	0.93	0.96	0.97	1.18	0.83	0.77	0.96	0.86	0.82	1.04
Total	**71.42**	**77.80**	**77.79**	**78.61**	**79.13**	**80.35**	**82.69**	**80.78**	**82.73**	**85.75**
Imports										
Crude Oil[3]	21.08	25.07	24.69	23.98	33.27	32.29	31.42	36.30	35.16	32.36
Petroleum Products[4]	5.16	6.34	6.06	4.93	8.74	6.83	4.41	11.56	8.27	6.51
Natural Gas	4.02	5.55	5.71	5.62	8.77	8.95	8.70	9.28	9.70	9.43
Other Imports[5]	0.69	0.92	0.92	0.92	1.15	1.15	1.15	1.23	1.23	1.24
Total	**30.95**	**37.88**	**37.38**	**35.45**	**51.93**	**49.22**	**45.68**	**58.37**	**54.36**	**49.53**
Exports										
Petroleum[6]	2.13	2.16	2.14	2.09	2.46	2.26	2.20	2.68	2.32	2.25
Natural Gas	0.70	0.65	0.65	0.65	0.88	0.86	0.86	0.86	0.83	0.82
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.89	0.65	0.65	0.65
Total	**3.95**	**3.88**	**3.86**	**3.81**	**4.23**	**4.01**	**3.95**	**4.19**	**3.80**	**3.71**
Discrepancy[7]	**0.18**	**0.12**	**0.05**	**-0.05**	**0.10**	**-0.05**	**-0.13**	**0.33**	**0.10**	**-0.15**
Consumption										
Petroleum Products[8]	39.09	45.34	44.84	43.74	53.36	51.30	49.64	57.67	54.42	52.34
Natural Gas	22.54	26.02	26.11	26.22	30.19	30.73	31.11	30.33	31.47	31.71
Coal	22.71	24.95	24.95	24.94	26.92	27.27	27.49	29.79	30.48	30.84
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.55	7.57	7.59	8.15	8.10	8.13
Other[9]	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.69**	**111.27**	**110.31**	**126.74**	**125.60**	**124.55**	**134.63**	**133.18**	**131.72**
Net Imports - Petroleum	**24.10**	**29.25**	**28.61**	**26.82**	**39.55**	**36.87**	**33.63**	**45.18**	**41.11**	**36.62**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[10] World Oil	27.73	20.99	25.00	33.99	20.99	28.50	36.74	20.99	30.31	39.24
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.61	3.64	3.67	4.32	4.53	4.55	4.68	4.79	4.84
Coal Minemouth Price (dollars per ton)	17.93	17.27	17.30	17.57	17.13	17.25	17.87	18.16	18.26	18.56
Average Electricity Price (cents per kilowatthour)	7.4	6.6	6.6	6.7	7.1	7.2	7.3	7.1	7.3	7.4

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Energy Consumption										
Residential										
Distillate Fuel	0.96	0.91	0.90	0.83	0.86	0.83	0.75	0.81	0.77	0.66
Kerosene	0.07	0.09	0.09	0.08	0.10	0.09	0.08	0.09	0.09	0.07
Liquefied Petroleum Gas	0.54	0.58	0.57	0.54	0.66	0.64	0.60	0.70	0.67	0.61
Petroleum Subtotal	1.58	1.58	1.56	1.45	1.62	1.56	1.43	1.60	1.53	1.34
Natural Gas	5.25	5.69	5.68	5.68	6.07	6.05	6.07	6.17	6.17	6.17
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.40	0.40	0.39	0.39	0.39	0.38	0.38	0.38
Electricity	4.37	5.03	5.02	5.01	5.81	5.79	5.78	6.20	6.18	6.16
Delivered Energy	**11.61**	**12.71**	**12.67**	**12.55**	**13.90**	**13.80**	**13.67**	**14.36**	**14.26**	**14.06**
Electricity Related Losses	9.71	10.81	10.80	10.79	11.81	11.77	11.75	12.40	12.35	12.27
Total	**21.31**	**23.52**	**23.47**	**23.34**	**25.71**	**25.56**	**25.42**	**26.76**	**26.62**	**26.33**
Commercial										
Distillate Fuel	0.52	0.63	0.62	0.56	0.75	0.71	0.63	0.82	0.77	0.65
Residual Fuel	0.07	0.07	0.07	0.07	0.08	0.08	0.07	0.08	0.08	0.08
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.11	0.11	0.10
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.87	0.86	0.80	1.00	0.96	0.87	1.08	1.02	0.90
Natural Gas	3.22	3.49	3.49	3.50	3.92	3.91	3.96	4.17	4.17	4.23
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	5.01	5.00	4.99	6.36	6.33	6.31	7.17	7.12	7.10
Delivered Energy	**8.29**	**9.55**	**9.53**	**9.47**	**11.47**	**11.38**	**11.32**	**12.59**	**12.49**	**12.40**
Electricity Related Losses	9.18	10.78	10.76	10.75	12.94	12.86	12.82	14.33	14.25	14.13
Total	**17.46**	**20.33**	**20.29**	**20.23**	**24.41**	**24.24**	**24.15**	**26.92**	**26.74**	**26.53**
Industrial[4]										
Distillate Fuel	1.03	1.05	1.04	1.02	1.16	1.14	1.09	1.22	1.19	1.13
Liquefied Petroleum Gas	2.09	2.32	2.30	2.26	2.64	2.59	2.53	2.84	2.74	2.63
Petrochemical Feedstock	1.32	1.49	1.48	1.47	1.57	1.55	1.53	1.58	1.57	1.54
Residual Fuel	0.28	0.34	0.34	0.34	0.43	0.38	0.39	0.45	0.38	0.36
Motor Gasoline[2]	0.31	0.31	0.31	0.31	0.35	0.35	0.35	0.37	0.37	0.37
Other Petroleum[5]	4.30	4.74	4.69	4.60	4.98	5.02	4.89	5.04	5.23	5.06
Petroleum Subtotal	9.31	10.26	10.17	9.99	11.13	11.03	10.79	11.50	11.47	11.10
Natural Gas	7.19	8.08	8.10	8.17	8.83	8.89	9.02	9.21	9.26	9.38
Lease and Plant Fuel[6]	1.15	1.21	1.20	1.22	1.30	1.32	1.39	1.27	1.31	1.37
Natural Gas Subtotal	8.34	9.28	9.31	9.39	10.13	10.21	10.41	10.48	10.57	10.75
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.39	1.43	1.42	1.42	1.42	1.42	1.54	1.42	1.42	1.77
Net Coal Coke Imports	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Coal Subtotal	2.11	2.03	2.03	2.03	1.90	1.89	2.01	1.84	1.83	2.18
Renewable Energy[7]	1.79	2.07	2.07	2.06	2.35	2.34	2.35	2.50	2.50	2.50
Electricity	3.31	3.79	3.78	3.76	4.21	4.19	4.21	4.40	4.39	4.41
Delivered Energy	**24.86**	**27.43**	**27.35**	**27.23**	**29.71**	**29.66**	**29.76**	**30.72**	**30.76**	**30.95**
Electricity Related Losses	7.35	8.15	8.13	8.11	8.56	8.52	8.56	8.80	8.78	8.78
Total	**32.21**	**35.58**	**35.47**	**35.34**	**38.27**	**38.19**	**38.32**	**39.52**	**39.53**	**39.73**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Transportation										
Distillate Fuel[8]	5.54	6.97	6.95	6.90	8.37	8.35	8.28	9.13	9.05	9.01
Jet Fuel[9]	3.26	4.05	4.04	3.99	4.84	4.74	4.69	5.09	4.89	4.84
Motor Gasoline[2]	16.64	19.32	19.14	18.59	22.94	22.31	21.48	24.94	24.04	22.98
Residual Fuel	0.62	0.56	0.56	0.56	0.58	0.58	0.58	0.58	0.58	0.58
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.25	0.29	0.29	0.29	0.32	0.31	0.31
Petroleum Subtotal	26.31	31.21	31.00	30.35	37.11	36.35	35.40	40.14	38.97	37.81
Pipeline Fuel Natural Gas	0.65	0.70	0.70	0.71	0.81	0.82	0.84	0.82	0.84	0.85
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**27.07**	**32.06**	**31.85**	**31.21**	**38.13**	**37.39**	**36.45**	**41.19**	**40.04**	**38.90**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.24
Total	**27.24**	**32.26**	**32.04**	**31.40**	**38.35**	**37.61**	**36.67**	**41.43**	**40.28**	**39.13**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.04	9.57	9.51	9.32	11.14	11.03	10.75	11.98	11.78	11.45
Kerosene	0.11	0.14	0.14	0.12	0.14	0.14	0.12	0.14	0.13	0.11
Jet Fuel[9]	3.26	4.05	4.04	3.99	4.84	4.74	4.69	5.09	4.89	4.84
Liquefied Petroleum Gas	2.75	3.05	3.03	2.95	3.50	3.42	3.31	3.73	3.60	3.43
Motor Gasoline[2]	16.98	19.67	19.49	18.94	23.33	22.70	21.87	25.35	24.45	23.39
Petrochemical Feedstock	1.32	1.49	1.48	1.47	1.57	1.55	1.53	1.58	1.57	1.54
Residual Fuel	0.97	0.97	0.97	0.97	1.08	1.03	1.04	1.11	1.03	1.02
Other Petroleum[12]	4.52	4.98	4.93	4.83	5.25	5.30	5.17	5.34	5.53	5.36
Petroleum Subtotal	37.96	43.93	43.58	42.60	50.86	49.90	48.48	54.32	52.98	51.14
Natural Gas	15.68	17.32	17.33	17.41	18.92	18.94	19.15	19.65	19.70	19.89
Lease and Plant Fuel Plant[6]	1.15	1.21	1.20	1.22	1.30	1.32	1.39	1.27	1.31	1.37
Pipeline Natural Gas	0.65	0.70	0.70	0.71	0.81	0.82	0.84	0.82	0.84	0.85
Natural Gas Subtotal	17.48	19.22	19.23	19.34	21.03	21.09	21.38	21.74	21.85	22.12
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.50	1.53	1.53	1.53	1.53	1.52	1.64	1.53	1.52	1.87
Net Coal Coke Imports	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Coal Subtotal	2.22	2.14	2.14	2.13	2.00	2.00	2.11	1.95	1.94	2.29
Renewable Energy[13]	2.28	2.55	2.55	2.55	2.83	2.82	2.83	2.97	2.97	2.98
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.91	13.89	13.85	16.49	16.41	16.40	17.89	17.81	17.79
Delivered Energy	**71.82**	**81.76**	**81.39**	**80.46**	**93.21**	**92.23**	**91.20**	**98.87**	**97.56**	**96.31**
Electricity Related Losses	26.40	29.93	29.88	29.85	33.53	33.37	33.35	35.76	35.62	35.41
Total	**98.22**	**111.69**	**111.27**	**110.31**	**126.74**	**125.60**	**124.55**	**134.63**	**133.18**	**131.72**
Electric Power[14]										
Distillate Fuel	0.33	0.40	0.39	0.37	1.29	0.42	0.38	2.09	0.45	0.40
Residual Fuel	0.80	1.01	0.87	0.77	1.21	0.98	0.78	1.26	0.98	0.79
Petroleum Subtotal	1.13	1.42	1.26	1.14	2.50	1.40	1.16	3.35	1.43	1.20
Natural Gas	5.06	6.80	6.87	6.89	9.16	9.64	9.72	8.58	9.61	9.59
Steam Coal	20.49	22.81	22.81	22.81	24.92	25.28	25.38	27.84	28.54	28.55
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[15]	3.62	4.30	4.30	4.34	4.73	4.75	4.76	5.18	5.14	5.16
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**38.28**	**43.84**	**43.77**	**43.70**	**50.02**	**49.79**	**49.75**	**53.65**	**53.43**	**53.20**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Total Energy Consumption										
Distillate Fuel	8.37	9.97	9.90	9.69	12.43	11.45	11.12	14.07	12.23	11.85
Kerosene	0.11	0.14	0.14	0.12	0.14	0.14	0.12	0.14	0.13	0.11
Jet Fuel[9]	3.26	4.05	4.04	3.99	4.84	4.74	4.69	5.09	4.89	4.84
Liquefied Petroleum Gas	2.75	3.05	3.03	2.95	3.50	3.42	3.31	3.73	3.60	3.43
Motor Gasoline[2]	16.98	19.67	19.49	18.94	23.33	22.70	21.87	25.35	24.45	23.39
Petrochemical Feedstock	1.32	1.49	1.48	1.47	1.57	1.55	1.53	1.58	1.57	1.54
Residual Fuel	1.77	1.99	1.84	1.74	2.30	2.01	1.82	2.36	2.02	1.82
Other Petroleum[12]	4.52	4.98	4.93	4.83	5.25	5.30	5.17	5.34	5.53	5.36
Petroleum Subtotal	39.09	45.34	44.84	43.74	53.36	51.30	49.64	57.67	54.42	52.34
Natural Gas	20.74	24.12	24.21	24.30	28.08	28.59	28.87	28.24	29.32	29.48
Lease and Plant Fuel[6]	1.15	1.21	1.20	1.22	1.30	1.32	1.39	1.27	1.31	1.37
Pipeline Natural Gas	0.65	0.70	0.70	0.71	0.81	0.82	0.84	0.82	0.84	0.85
Natural Gas Subtotal	22.54	26.02	26.11	26.22	30.19	30.73	31.11	30.33	31.47	31.71
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	21.99	24.34	24.34	24.34	26.45	26.80	27.02	29.37	30.07	30.42
Net Coal Coke Imports	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Coal Subtotal	22.71	24.95	24.95	24.94	26.92	27.27	27.49	29.79	30.48	30.84
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[15]	5.89	6.85	6.85	6.88	7.55	7.57	7.59	8.15	8.10	8.13
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.69**	**111.27**	**110.31**	**126.74**	**125.60**	**124.55**	**134.63**	**133.18**	**131.72**
Energy Use and Related Statistics										
Delivered Energy Use	71.82	81.76	81.39	80.46	93.21	92.23	91.20	98.87	97.56	96.31
Total Energy Use	98.22	111.69	111.27	110.31	126.74	125.60	124.55	134.63	133.18	131.72
Population (millions)	291.39	310.12	310.12	310.12	336.99	336.99	336.99	350.64	350.64	350.64
Gross Domestic Product (billion 2000 dollars)	10381	13108	13084	13032	17679	17634	17623	20341	20292	20263
Carbon Dioxide Emissions										
Carbon Dioxide Emissions (million metric tons)	5788.7	6657.2	6626.8	6545.6	7604.8	7519.6	7432.4	8171.6	8062.3	7949.6

[1]Includes wood used for residential heating. See Table C4 and/or Table C17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Residential	**15.81**	**14.20**	**14.33**	**14.66**	**15.23**	**15.64**	**15.90**	**15.74**	**16.13**	**16.47**
Primary Energy[1]	9.68	8.22	8.35	8.72	8.83	9.21	9.46	9.27	9.62	9.98
Petroleum Products[2]	11.27	9.91	10.44	12.26	10.23	11.36	12.87	10.53	11.93	13.94
Distillate Fuel	9.57	7.77	8.29	9.83	7.94	8.85	10.08	8.03	9.12	10.65
Liquefied Petroleum Gas	14.58	13.71	14.25	16.45	13.63	15.06	16.78	13.85	15.65	17.91
Natural Gas	9.22	7.76	7.79	7.83	8.47	8.66	8.67	8.96	9.07	9.13
Electricity	25.42	22.86	22.96	23.12	23.72	24.12	24.27	23.85	24.24	24.40
Commercial	**15.63**	**13.61**	**13.76**	**14.05**	**15.24**	**15.70**	**15.95**	**15.73**	**16.20**	**16.53**
Primary Energy[1]	7.92	6.68	6.81	7.15	7.19	7.54	7.79	7.49	7.82	8.18
Petroleum Products[2]	8.03	6.57	7.13	8.89	6.53	7.55	8.89	6.62	7.84	9.65
Distillate Fuel	7.03	5.75	6.30	7.97	5.84	6.76	7.96	5.99	7.06	8.75
Residual Fuel	4.96	3.66	4.26	5.65	3.65	4.81	6.06	3.64	5.08	6.44
Natural Gas	8.08	6.84	6.87	6.90	7.50	7.68	7.69	7.85	7.96	8.01
Electricity	23.24	19.79	19.93	20.13	21.59	22.10	22.32	21.87	22.40	22.68
Industrial[3]	**7.78**	**6.62**	**6.85**	**7.58**	**7.17**	**7.75**	**8.25**	**7.43**	**8.13**	**8.76**
Primary Energy	6.49	5.29	5.55	6.40	5.63	6.27	6.83	5.87	6.64	7.37
Petroleum Products[2]	8.29	6.73	7.24	8.96	6.76	7.88	9.09	6.94	8.36	10.06
Distillate Fuel	7.24	6.23	6.78	8.45	6.44	7.37	8.55	6.68	7.73	9.39
Liquefied Petroleum Gas	12.57	9.49	10.02	12.21	9.35	10.74	12.26	9.56	11.35	13.37
Residual Fuel	4.59	3.26	3.87	5.17	3.18	4.34	5.60	3.18	4.62	5.99
Natural Gas[4]	5.56	4.35	4.37	4.41	5.05	5.23	5.26	5.35	5.47	5.53
Metallurgical Coal	1.85	1.82	1.82	1.82	1.74	1.75	1.75	1.68	1.68	1.69
Steam Coal	1.55	1.56	1.56	1.58	1.56	1.56	1.53	1.60	1.60	1.45
Electricity	15.03	13.79	13.84	13.92	15.14	15.47	15.58	15.41	15.75	15.89
Transportation	**11.46**	**10.39**	**10.95**	**12.65**	**10.08**	**11.16**	**12.41**	**10.15**	**11.46**	**13.18**
Primary Energy	11.43	10.37	10.93	12.63	10.05	11.13	12.38	10.13	11.44	13.16
Petroleum Products[2]	11.43	10.37	10.93	12.64	10.05	11.13	12.39	10.13	11.44	13.17
Distillate Fuel[5]	10.92	10.19	10.76	12.51	9.72	10.66	11.84	9.81	10.85	12.50
Jet Fuel[6]	6.46	5.68	6.25	7.86	5.66	6.58	7.89	5.75	6.93	8.75
Motor Gasoline[7]	12.93	11.76	12.32	14.08	11.34	12.52	13.84	11.36	12.81	14.61
Residual Fuel	4.49	3.10	3.74	5.17	3.09	4.28	5.59	3.08	4.56	5.98
Liquefied Petroleum Gas[8]	16.65	14.72	15.24	17.25	14.29	15.66	17.26	14.40	16.24	18.15
Natural Gas[9]	9.04	8.48	8.56	8.61	9.11	9.45	9.53	9.35	9.69	9.78
Ethanol (E85)[10]	16.23	16.67	17.11	19.09	17.06	17.22	18.70	17.47	18.13	19.69
Electricity	20.64	18.71	18.81	18.96	19.60	19.99	20.15	19.58	19.96	20.15
Average End-Use Energy	**11.50**	**10.22**	**10.56**	**11.55**	**10.68**	**11.42**	**12.15**	**10.95**	**11.83**	**12.82**
Primary Energy	9.32	8.23	8.61	9.77	8.38	9.18	10.01	8.59	9.55	10.69
Electricity	21.74	19.26	19.36	19.52	20.68	21.11	21.26	20.95	21.38	21.58
Electric Power[11]										
Fossil Fuel Average	2.24	2.03	2.06	2.12	2.39	2.45	2.50	2.43	2.46	2.52
Petroleum Products	5.28	3.91	4.55	6.04	4.26	5.10	6.42	4.50	5.42	6.98
Distillate Fuel	6.48	4.83	5.36	6.95	4.98	6.01	7.21	5.10	6.33	8.06
Residual Fuel	4.79	3.54	4.19	5.61	3.50	4.71	6.04	3.50	5.00	6.44
Natural Gas	5.46	4.24	4.27	4.31	5.00	5.20	5.23	5.30	5.44	5.50
Steam Coal	1.28	1.25	1.25	1.26	1.24	1.25	1.28	1.29	1.31	1.33

Table C3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Average Price to All Users[12]										
Petroleum Products[2]	10.51	9.34	9.91	11.63	9.11	10.29	11.57	9.18	10.66	12.41
Distillate Fuel	9.90	8.97	9.53	11.27	8.57	9.79	11.02	8.51	10.03	11.74
Jet Fuel	6.46	5.68	6.25	7.86	5.66	6.58	7.89	5.75	6.93	8.75
Liquefied Petroleum Gas	13.04	10.46	10.99	13.16	10.35	11.74	13.28	10.54	12.34	14.38
Motor Gasoline[7]	12.93	11.74	12.31	14.07	11.33	12.51	13.82	11.35	12.80	14.59
Residual Fuel	4.66	3.37	3.99	5.39	3.34	4.52	5.80	3.34	4.81	6.20
Natural Gas	6.86	5.49	5.52	5.55	6.13	6.30	6.32	6.51	6.59	6.65
Coal	1.30	1.27	1.27	1.28	1.26	1.27	1.30	1.31	1.32	1.37
Ethanol (E85)[10]	16.23	16.67	17.11	19.09	17.06	17.22	18.70	17.47	18.13	19.69
Electricity	21.74	19.26	19.36	19.52	20.68	21.11	21.26	20.95	21.38	21.58
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)										
Residential	177.17	174.78	175.88	178.08	205.81	209.76	211.21	220.02	223.86	225.37
Commercial	128.15	128.89	129.92	131.91	173.53	177.28	179.18	196.75	200.93	203.65
Industrial	147.11	135.96	139.57	151.95	159.31	169.93	179.57	171.50	184.96	198.26
Transportation	302.59	325.97	341.13	385.90	376.13	407.83	441.71	409.89	449.31	501.32
Total Non-Renewable Expenditures	755.02	765.59	786.50	847.84	914.77	964.80	1011.67	998.16	1059.05	1128.59
Transportation Renewable Expenditures	0.02	0.03	0.03	0.04	0.06	0.07	0.07	0.07	0.08	0.09
Total Expenditures	**755.04**	**765.63**	**786.54**	**847.88**	**914.83**	**964.87**	**1011.74**	**998.23**	**1059.13**	**1128.69**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: *2003 prices for motor gasoline, distillate, and jet fuel are based on:* Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C4. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Crude Oil										
Domestic Crude Production[1]	5.68	5.98	6.02	6.16	4.98	5.21	5.48	4.46	4.73	5.18
Alaska	0.97	0.80	0.81	0.83	0.78	0.86	0.93	0.55	0.61	0.71
Lower 48 States	4.71	5.19	5.22	5.33	4.20	4.35	4.55	3.91	4.12	4.47
Net Imports	9.65	11.48	11.31	10.98	15.25	14.80	14.40	16.63	16.11	14.83
Gross Imports	9.66	11.50	11.32	11.00	15.26	14.81	14.41	16.64	16.12	14.84
Exports	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other Crude Supply[2]	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.31**	**17.47**	**17.33**	**17.14**	**20.22**	**20.01**	**19.88**	**21.09**	**20.84**	**20.01**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.72	1.96	1.96	1.98	2.01	2.04	2.12	1.99	2.04	2.12
Net Product Imports	1.58	2.20	2.06	1.47	3.24	2.31	1.11	4.55	3.00	2.12
Gross Refined Product Imports[3]	1.85	2.09	1.99	1.38	2.85	1.90	0.76	4.11	2.47	1.65
Unfinished Oil Imports	0.34	0.64	0.59	0.59	0.97	0.91	0.85	1.08	1.02	0.95
Blending Components	0.41	0.48	0.48	0.46	0.57	0.55	0.53	0.62	0.60	0.57
Exports	1.01	1.00	0.99	0.97	1.15	1.05	1.02	1.26	1.08	1.05
Refinery Processing Gain[4]	1.00	1.07	1.11	1.14	1.38	1.50	1.55	1.40	1.56	1.62
Other Supply[5]	0.69	0.52	0.53	0.69	0.49	0.46	0.80	0.52	0.50	0.99
Total Primary Supply[6]	**20.30**	**23.23**	**22.98**	**22.41**	**27.34**	**26.32**	**25.46**	**29.55**	**27.93**	**26.86**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	8.93	10.38	10.28	9.99	12.30	11.97	11.53	13.37	12.89	12.33
Jet Fuel[8]	1.57	1.96	1.95	1.93	2.34	2.29	2.27	2.46	2.36	2.34
Distillate Fuel[9]	3.95	4.73	4.70	4.60	5.90	5.44	5.29	6.68	5.81	5.63
Residual Fuel	0.77	0.87	0.80	0.76	1.00	0.88	0.79	1.03	0.88	0.79
Other[10]	4.77	5.30	5.25	5.14	5.80	5.74	5.59	6.01	5.98	5.76
Total	**20.00**	**23.23**	**22.98**	**22.41**	**27.34**	**26.32**	**25.47**	**29.55**	**27.93**	**26.85**
Refined Petroleum Products Supplied										
Residential and Commercial	1.28	1.35	1.33	1.24	1.46	1.41	1.29	1.49	1.42	1.26
Industrial[11]	4.87	5.38	5.33	5.24	5.87	5.81	5.68	6.10	6.05	5.85
Transportation	13.35	15.87	15.76	15.42	18.87	18.48	17.98	20.43	19.82	19.21
Electric Power[12]	0.50	0.63	0.56	0.51	1.13	0.62	0.52	1.53	0.64	0.53
Total	**20.00**	**23.23**	**22.98**	**22.41**	**27.34**	**26.32**	**25.47**	**29.55**	**27.93**	**26.85**
Discrepancy[13]	**0.29**	**-0.00**	**-0.00**	**-0.00**	**0.00**	**0.00**	**-0.01**	**-0.00**	**-0.00**	**0.00**
World Oil Price (2003 dollars per barrel)[14]	27.73	20.99	25.00	33.99	20.99	28.50	36.74	20.99	30.31	39.24
Import Share of Product Supplied	0.56	0.59	0.58	0.56	0.68	0.65	0.61	0.72	0.68	0.63
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2003 dollars)	113.78	108.97	125.14	157.10	147.68	180.07	207.96	172.41	215.89	245.02
Domestic Refinery Distillation Capacity[15]	16.8	18.8	18.7	18.6	21.6	21.4	21.3	22.5	22.3	21.4
Capacity Utilization Rate (percent)	93.0	94.4	94.0	93.6	94.9	94.8	94.8	94.9	94.9	94.8

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers; natural gas converted to liquid fuel; and coal converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Average refiner acquisition cost for imported crude oil.
[15]End-of-year operable capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2003 data: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C5. Petroleum Product Prices
(2003 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
World Oil Price (2003 dollars per barrel)	**27.73**	**20.99**	**25.00**	**33.99**	**20.99**	**28.50**	**36.74**	**20.99**	**30.31**	**39.24**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	132.7	107.8	114.9	136.3	110.1	122.7	139.8	111.3	126.4	147.7
Liquefied Petroleum Gas	125.4	117.9	122.6	141.5	117.2	129.5	144.3	119.1	134.6	154.0
Commercial										
Distillate Fuel	97.3	79.3	86.9	109.9	80.6	93.2	109.7	82.6	97.3	120.7
Residual Fuel	74.3	54.8	63.7	84.6	54.6	71.9	90.7	54.4	76.0	96.4
Residual Fuel (2003 dollars per barrel)	31.21	23.01	26.77	35.51	22.93	30.21	38.09	22.86	31.92	40.50
Industrial[1]										
Distillate Fuel	100.2	85.7	93.3	116.2	88.4	101.2	117.4	91.6	106.2	128.9
Liquefied Petroleum Gas	108.1	81.6	86.1	105.0	80.4	92.3	105.4	82.2	97.6	115.0
Residual Fuel	68.7	48.7	57.9	77.4	47.7	64.9	83.8	47.6	69.1	89.7
Residual Fuel (2003 dollars per barrel)	28.84	20.46	24.33	32.51	20.01	27.27	35.18	19.97	29.02	37.66
Transportation										
Diesel Fuel (distillate)[2]	150.4	139.7	147.5	171.5	133.2	146.1	162.2	134.5	148.6	171.2
Jet Fuel[3]	87.2	76.7	84.3	106.1	76.3	88.8	106.5	77.6	93.5	118.1
Motor Gasoline[4]	160.3	145.4	152.4	174.1	140.3	154.9	171.2	140.5	158.5	180.7
Liquid Petroleum Gas	143.2	126.6	131.1	148.3	122.9	134.7	148.5	123.8	139.7	156.1
Residual Fuel	67.3	46.4	56.0	77.4	46.3	64.1	83.7	46.1	68.3	89.6
Residual Fuel (2003 dollars per barrel)	28.25	19.51	23.50	32.49	19.43	26.92	35.16	19.38	28.68	37.61
Ethanol (E85)[5]	152.4	156.4	160.5	179.1	160.1	161.6	175.5	163.9	170.1	184.8
Electric Power[6]										
Distillate Fuel	89.8	67.0	74.4	96.3	69.0	83.3	100.0	70.8	87.8	111.8
Residual Fuel	71.7	53.0	62.7	84.0	52.4	70.5	90.3	52.4	74.9	96.3
Residual Fuel (2003 dollars per barrel)	30.12	22.28	26.32	35.29	22.01	29.63	37.94	22.00	31.45	40.46
Refined Petroleum Product Prices[7]										
Distillate Fuel	136.7	123.3	131.0	154.9	117.8	134.4	151.3	117.0	137.7	161.2
Jet Fuel[3]	87.2	76.7	84.3	106.1	76.3	88.8	106.5	77.6	93.5	118.1
Liquefied Petroleum Gas	112.1	90.0	94.5	113.2	89.0	101.0	114.2	90.7	106.1	123.6
Motor Gasoline[4]	160.3	145.2	152.2	174.0	140.1	154.8	171.1	140.4	158.4	180.6
Residual Fuel	69.8	50.5	59.8	80.6	50.0	67.7	86.9	50.0	72.0	92.8
Residual Fuel (2003 dollars per barrel)	29.32	21.21	25.11	33.86	21.02	28.43	36.48	21.00	30.22	38.99
Average	**136.6**	**121.1**	**128.3**	**150.0**	**117.6**	**132.4**	**148.6**	**118.3**	**136.8**	**158.8**

[1]*Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.*
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2003 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2003 world oil price: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

Table C6. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
World Oil Price (2003 dollars per barrel)[1]	**27.73**	**20.99**	**25.00**	**33.99**	**20.99**	**28.50**	**36.74**	**20.99**	**30.31**	**39.24**
Production (Conventional)[2]										
Industrialized Countries										
U.S. (50 states)	9.09	9.55	9.61	9.95	8.86	9.21	9.76	8.36	8.82	9.60
Canada	2.25	1.82	1.83	1.91	1.58	1.60	1.70	1.54	1.57	1.68
Mexico	3.80	4.17	4.21	4.45	4.50	4.62	4.97	4.69	4.85	5.25
Western Europe[3]	6.69	6.32	6.35	6.65	5.44	5.51	5.85	4.92	5.00	5.35
Japan	0.13	0.08	0.08	0.09	0.06	0.06	0.09	0.05	0.06	0.09
Australia and New Zealand	0.66	0.95	0.96	1.01	0.86	0.89	0.95	0.83	0.86	0.93
Total Industrialized	**22.62**	**22.89**	**23.05**	**24.06**	**21.30**	**21.89**	**23.32**	**20.40**	**21.16**	**22.90**
Eurasia										
Former Soviet Union										
Russia	8.34	9.89	9.98	10.64	10.63	10.90	11.87	10.76	11.11	12.20
Caspian Area[4]	1.87	3.11	3.14	3.35	5.10	5.23	5.70	6.03	6.22	6.83
Eastern Europe[5]	0.22	0.33	0.33	0.35	0.40	0.41	0.44	0.44	0.45	0.48
Total Eurasia	**10.44**	**13.33**	**13.46**	**14.34**	**16.13**	**16.54**	**18.01**	**17.23**	**17.78**	**19.52**
Developing Countries										
OPEC[6]										
Asia	1.38	1.57	1.47	1.19	1.78	1.51	1.14	1.88	1.56	1.16
Middle East	20.95	26.08	24.45	19.84	38.02	32.37	24.44	46.42	38.47	28.62
North Africa	2.99	3.67	3.44	2.79	5.21	4.44	3.35	5.77	4.78	3.56
West Africa	1.98	2.51	2.36	1.91	3.67	3.13	2.36	4.52	3.74	2.78
South America	2.85	3.56	3.34	2.71	5.21	4.44	3.35	6.27	5.20	3.87
Non-OPEC										
China	3.10	3.60	3.64	3.84	3.40	3.49	3.76	3.30	3.41	3.69
Other Asia	2.59	2.62	2.65	2.80	2.64	2.71	2.92	2.56	2.64	2.86
Middle East[7]	1.81	2.22	2.24	2.37	2.51	2.57	2.77	2.69	2.78	3.01
Africa	2.94	3.72	3.75	4.04	5.31	5.44	6.00	6.36	6.56	7.31
South and Central America	3.93	4.48	4.53	4.83	5.77	5.91	6.44	6.22	6.42	7.05
Total Developing Countries	**44.52**	**54.05**	**51.87**	**46.31**	**73.52**	**66.02**	**56.52**	**86.00**	**75.57**	**63.93**
Total Production (Conventional)	**77.58**	**90.26**	**88.38**	**84.72**	**110.95**	**104.45**	**97.85**	**123.63**	**114.51**	**106.34**
Production[8] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.01	0.00	0.00	0.19	0.00	0.00	0.31
Other North America	0.93	1.63	1.73	1.95	2.81	3.33	3.78	2.94	3.46	4.14
Western Europe	0.04	0.04	0.04	0.05	0.03	0.05	0.06	0.03	0.05	0.06
Asia	0.03	0.03	0.04	0.05	0.02	0.05	0.08	0.02	0.07	0.10
Middle East[7]	0.03	0.03	0.12	0.12	0.03	0.21	0.28	0.04	0.25	0.35
Africa	0.21	0.16	0.23	0.26	0.18	0.28	0.41	0.19	0.32	0.47
South and Central America	0.57	0.82	0.82	1.23	1.27	1.48	2.43	1.18	1.50	2.79
Total Production (Nonconventional)	**1.79**	**2.70**	**2.98**	**3.68**	**4.34**	**5.40**	**7.23**	**4.40**	**5.65**	**8.22**
Total Production	**79.37**	**92.97**	**91.35**	**88.39**	**115.30**	**109.85**	**105.08**	**128.04**	**120.17**	**114.56**

Table C6. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price	Low World Oil Price	Reference	High A World Oil Price
Consumption[8]										
Industrialized Countries										
U.S. (50 states)	20.00	23.23	22.98	22.41	27.34	26.32	25.47	29.55	27.93	26.85
U.S. Territories	0.36	0.40	0.38	0.35	0.48	0.43	0.39	0.54	0.47	0.42
Canada	2.17	2.39	2.30	2.15	2.88	2.62	2.39	3.16	2.80	2.55
Mexico	2.02	2.43	2.36	2.25	3.24	2.88	2.51	4.13	3.48	2.93
Western Europe[3]	14.22	15.00	14.72	14.22	16.15	15.45	14.82	16.60	15.71	15.06
Japan	5.58	5.91	5.70	5.34	6.46	5.69	4.95	6.93	5.84	4.99
Australia and New Zealand	1.04	1.29	1.27	1.23	1.60	1.54	1.49	1.77	1.69	1.63
Total Industrialized	**45.38**	**50.66**	**49.72**	**47.95**	**58.15**	**54.93**	**52.01**	**62.68**	**57.92**	**54.44**
Eurasia										
Former Soviet Union	4.18	4.46	4.39	4.26	5.94	5.74	5.55	6.73	6.45	6.24
Eastern Europe[5]	1.42	1.58	1.56	1.53	1.93	1.89	1.85	2.15	2.09	2.05
Total Eurasia	**5.59**	**6.04**	**5.95**	**5.79**	**7.88**	**7.63**	**7.41**	**8.88**	**8.54**	**8.28**
Developing Countries										
China	5.54	7.84	7.63	7.27	11.75	11.06	10.45	13.79	12.79	12.08
India	2.19	2.85	2.79	2.69	4.65	4.37	4.09	5.75	5.29	4.92
South Korea	2.17	2.57	2.51	2.39	2.96	2.75	2.56	3.21	2.93	2.72
Other Asia	5.74	7.37	7.28	7.11	9.76	9.47	9.20	11.07	10.66	10.35
Middle East[7]	5.58	6.90	6.83	6.73	8.49	8.34	8.21	9.28	9.08	8.93
Africa	2.72	3.16	3.13	3.07	4.26	4.13	3.99	4.85	4.66	4.49
South and Central America	4.69	5.89	5.81	5.69	7.68	7.48	7.30	8.89	8.61	8.40
Total Developing Countries	**28.64**	**36.57**	**35.98**	**34.94**	**49.55**	**47.59**	**45.80**	**56.83**	**54.01**	**51.90**
Total Consumption	**79.60**	**93.27**	**91.65**	**88.68**	**115.57**	**110.14**	**105.22**	**128.39**	**120.47**	**114.62**
OPEC Production[10]	30.60	38.04	35.79	29.48	54.88	47.21	36.75	65.79	55.13	42.44
Non-OPEC Production[10]	48.77	54.93	55.56	58.91	60.42	62.64	68.33	62.25	65.04	72.13
Net Eurasia Exports	4.84	7.29	7.51	8.55	8.26	8.92	10.60	8.35	9.25	11.23
OPEC Market Share	0.39	0.41	0.39	0.33	0.48	0.43	0.35	0.51	0.46	0.37

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates, natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2005 National Energy Modeling System runs LW2005.D102004A, AEO2005.D102004A, and HW2005.D102004A.

October Futures and High B Oil Price Case Comparisons

Table D1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Production										
Crude Oil and Lease Condensate	12.03	12.75	13.04	13.18	11.03	11.35	12.21	10.01	10.54	11.22
Natural Gas Plant Liquids	2.34	2.66	2.70	2.78	2.80	2.86	3.01	2.81	2.84	3.00
Dry Natural Gas	19.58	20.97	21.34	22.09	22.48	23.09	24.51	22.42	22.72	24.18
Coal	22.66	25.10	25.05	25.23	27.04	27.07	29.73	29.90	29.91	35.26
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.57	7.60	7.76	8.10	8.26	8.32
Other[2]	0.93	0.97	1.16	1.16	0.77	0.90	1.01	0.82	0.97	1.13
Total	**71.42**	**77.79**	**78.64**	**79.81**	**80.35**	**81.54**	**86.89**	**82.73**	**83.91**	**91.77**
Imports										
Crude Oil[3]	21.08	24.69	24.30	23.87	32.29	31.90	29.23	35.16	34.55	31.20
Petroleum Products[4]	5.16	6.06	4.95	4.19	6.83	5.41	3.45	8.27	6.69	4.06
Natural Gas	4.02	5.71	5.49	5.03	8.95	8.81	7.20	9.70	9.63	6.61
Other Imports[5]	0.69	0.92	0.92	0.92	1.15	1.15	1.15	1.23	1.23	1.23
Total	**30.95**	**37.38**	**35.66**	**34.00**	**49.22**	**47.28**	**41.03**	**54.36**	**52.10**	**43.09**
Exports										
Petroleum[6]	2.13	2.14	2.11	2.08	2.26	2.22	2.17	2.32	2.28	2.22
Natural Gas	0.70	0.65	0.64	0.64	0.86	0.86	0.81	0.83	0.82	0.75
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.81	0.65	0.65	0.64
Total	**3.95**	**3.86**	**3.81**	**3.78**	**4.01**	**3.97**	**3.80**	**3.80**	**3.75**	**3.61**
Discrepancy[7]	**0.18**	**0.05**	**-0.06**	**-0.03**	**-0.05**	**-0.22**	**-0.22**	**0.10**	**-0.13**	**-0.21**
Consumption										
Petroleum Products[8]	39.09	44.84	43.98	43.37	51.30	50.22	48.66	54.42	53.21	51.13
Natural Gas	22.54	26.11	26.29	26.26	30.73	31.21	30.31	31.47	31.71	29.48
Coal	22.71	24.95	24.91	25.02	27.27	27.31	28.89	30.48	30.50	33.83
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.88	7.57	7.61	7.76	8.10	8.27	8.32
Other[9]	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.27**	**110.55**	**110.05**	**125.60**	**125.07**	**124.34**	**133.18**	**132.40**	**131.46**
Net Imports - Petroleum	**24.10**	**28.61**	**27.15**	**25.98**	**36.87**	**35.09**	**30.51**	**41.11**	**38.96**	**33.04**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[10]	27.73	25.00	30.99	37.00	28.50	33.67	44.33	30.31	35.00	48.00
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.64	3.63	3.74	4.53	4.45	4.60	4.79	4.83	5.32
Coal Minemouth Price (dollars per ton)	17.93	17.30	17.45	17.69	17.25	17.54	18.39	18.26	18.52	20.41
Average Electricity Price (cents per kilowatthour)	7.4	6.6	6.6	6.7	7.2	7.2	7.3	7.3	7.3	7.4

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Energy Consumption										
Residential										
Distillate Fuel	0.96	0.90	0.80	0.76	0.83	0.76	0.64	0.77	0.70	0.56
Kerosene	0.07	0.09	0.06	0.05	0.09	0.06	0.05	0.09	0.06	0.05
Liquefied Petroleum Gas	0.54	0.57	0.54	0.52	0.64	0.61	0.57	0.67	0.63	0.58
Petroleum Subtotal	1.58	1.56	1.40	1.33	1.56	1.43	1.26	1.53	1.39	1.18
Natural Gas	5.25	5.68	5.64	5.63	6.05	6.07	6.03	6.17	6.16	6.07
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.39	0.39	0.39	0.39	0.39	0.38	0.38	0.38
Electricity	4.37	5.02	5.01	5.00	5.79	5.78	5.77	6.18	6.17	6.15
Delivered Energy	**11.61**	**12.67**	**12.46**	**12.37**	**13.80**	**13.68**	**13.46**	**14.26**	**14.11**	**13.80**
Electricity Related Losses	9.71	10.80	10.78	10.77	11.77	11.76	11.63	12.35	12.33	12.09
Total	**21.31**	**23.47**	**23.25**	**23.15**	**25.56**	**25.44**	**25.09**	**26.62**	**26.44**	**25.88**
Commercial										
Distillate Fuel	0.52	0.62	0.57	0.54	0.71	0.63	0.58	0.77	0.66	0.60
Residual Fuel	0.07	0.07	0.07	0.07	0.08	0.07	0.07	0.08	0.08	0.07
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.11	0.11	0.10
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.86	0.81	0.78	0.96	0.88	0.82	1.02	0.91	0.84
Natural Gas	3.22	3.49	3.49	3.49	3.91	3.97	3.96	4.17	4.23	4.19
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	5.00	5.00	4.99	6.33	6.32	6.29	7.12	7.11	7.06
Delivered Energy	**8.29**	**9.53**	**9.48**	**9.44**	**11.38**	**11.34**	**11.25**	**12.49**	**12.43**	**12.28**
Electricity Related Losses	9.18	10.76	10.75	10.74	12.86	12.83	12.67	14.25	14.21	13.87
Total	**17.46**	**20.29**	**20.23**	**20.19**	**24.24**	**24.18**	**23.92**	**26.74**	**26.65**	**26.15**
Industrial[4]										
Distillate Fuel	1.03	1.04	1.03	1.02	1.14	1.10	1.09	1.19	1.14	1.14
Liquefied Petroleum Gas	2.09	2.30	2.28	2.26	2.59	2.54	2.50	2.74	2.65	2.57
Petrochemical Feedstock	1.32	1.48	1.48	1.47	1.55	1.55	1.52	1.57	1.57	1.52
Residual Fuel	0.28	0.34	0.32	0.29	0.38	0.40	0.34	0.38	0.41	0.35
Motor Gasoline[2]	0.31	0.31	0.31	0.31	0.35	0.35	0.35	0.37	0.37	0.37
Other Petroleum[5]	4.30	4.69	4.65	4.61	5.02	4.98	4.78	5.23	5.18	4.94
Petroleum Subtotal	9.31	10.17	10.08	9.97	11.03	10.92	10.58	11.47	11.32	10.88
Natural Gas	7.19	8.10	8.18	8.22	8.89	9.06	9.03	9.26	9.39	9.28
Lease and Plant Fuel[6]	1.15	1.20	1.22	1.26	1.32	1.37	1.45	1.31	1.32	1.41
Natural Gas Subtotal	8.34	9.31	9.40	9.48	10.21	10.42	10.49	10.57	10.71	10.69
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.39	1.42	1.42	1.49	1.42	1.42	2.59	1.42	1.41	3.47
Net Coal Coke Imports	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Coal Subtotal	2.11	2.03	2.03	2.09	1.89	1.89	3.06	1.83	1.83	3.88
Renewable Energy[7]	1.79	2.07	2.07	2.06	2.34	2.35	2.35	2.50	2.50	2.51
Electricity	3.31	3.78	3.79	3.78	4.19	4.22	4.22	4.39	4.43	4.43
Delivered Energy	**24.86**	**27.35**	**27.35**	**27.38**	**29.66**	**29.81**	**30.69**	**30.76**	**30.80**	**32.40**
Electricity Related Losses	7.35	8.13	8.14	8.14	8.52	8.58	8.51	8.78	8.85	8.71
Total	**32.21**	**35.47**	**35.50**	**35.52**	**38.19**	**38.39**	**39.20**	**39.53**	**39.65**	**41.11**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Transportation										
Distillate Fuel[8]	5.54	6.95	6.94	6.91	8.35	8.30	8.30	9.05	9.03	8.98
Jet Fuel[9]	3.26	4.04	4.00	3.97	4.74	4.70	4.66	4.89	4.85	4.81
Motor Gasoline[2]	16.64	19.14	18.73	18.39	22.31	21.83	20.94	24.04	23.46	22.25
Residual Fuel	0.62	0.56	0.56	0.56	0.58	0.58	0.58	0.58	0.58	0.59
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.25	0.29	0.29	0.29	0.31	0.32	0.31
Petroleum Subtotal	26.31	31.00	30.54	30.15	36.35	35.78	34.86	38.97	38.33	37.03
Pipeline Fuel Natural Gas	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**27.07**	**31.85**	**31.40**	**31.01**	**37.39**	**36.84**	**35.91**	**40.04**	**39.42**	**38.09**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.23
Total	**27.24**	**32.04**	**31.59**	**31.20**	**37.61**	**37.06**	**36.13**	**40.28**	**39.65**	**38.32**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.04	9.51	9.34	9.23	11.03	10.79	10.61	11.78	11.53	11.27
Kerosene	0.11	0.14	0.10	0.09	0.14	0.10	0.10	0.13	0.10	0.09
Jet Fuel[9]	3.26	4.04	4.00	3.97	4.74	4.70	4.66	4.89	4.85	4.81
Liquefied Petroleum Gas	2.75	3.03	2.98	2.94	3.42	3.34	3.25	3.60	3.48	3.34
Motor Gasoline[2]	16.98	19.49	19.08	18.74	22.70	22.22	21.33	24.45	23.87	22.66
Petrochemical Feedstock	1.32	1.48	1.48	1.47	1.55	1.55	1.52	1.57	1.57	1.52
Residual Fuel	0.97	0.97	0.96	0.93	1.03	1.05	1.00	1.03	1.06	1.01
Other Petroleum[12]	4.52	4.93	4.89	4.85	5.30	5.25	5.05	5.53	5.48	5.24
Petroleum Subtotal	37.96	43.58	42.82	42.23	49.90	49.01	47.52	52.98	51.95	49.94
Natural Gas	15.68	17.33	17.37	17.40	18.94	19.20	19.12	19.70	19.90	19.65
Lease and Plant Fuel Plant[6]	1.15	1.20	1.22	1.26	1.32	1.37	1.45	1.31	1.32	1.41
Pipeline Natural Gas	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Natural Gas Subtotal	17.48	19.23	19.30	19.37	21.09	21.41	21.42	21.85	22.08	21.89
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	1.50	1.53	1.53	1.60	1.52	1.52	2.70	1.52	1.52	3.58
Net Coal Coke Imports	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Coal Subtotal	2.22	2.14	2.14	2.20	2.00	2.00	3.17	1.94	1.94	3.99
Renewable Energy[13]	2.28	2.55	2.55	2.55	2.82	2.83	2.83	2.97	2.98	2.98
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.89	13.88	13.86	16.41	16.43	16.38	17.81	17.82	17.76
Delivered Energy	**71.82**	**81.39**	**80.69**	**80.21**	**92.23**	**91.68**	**91.31**	**97.56**	**96.76**	**96.56**
Electricity Related Losses	26.40	29.88	29.86	29.84	33.37	33.39	33.03	35.62	35.64	34.91
Total	**98.22**	**111.27**	**110.55**	**110.05**	**125.60**	**125.07**	**124.34**	**133.18**	**132.40**	**131.46**
Electric Power[14]										
Distillate Fuel	0.33	0.39	0.38	0.37	0.42	0.39	0.37	0.45	0.41	0.41
Residual Fuel	0.80	0.87	0.78	0.77	0.98	0.82	0.77	0.98	0.86	0.78
Petroleum Subtotal	1.13	1.26	1.16	1.14	1.40	1.21	1.14	1.43	1.27	1.19
Natural Gas	5.06	6.87	6.99	6.89	9.64	9.80	8.89	9.61	9.63	7.58
Steam Coal	20.49	22.81	22.77	22.82	25.28	25.32	25.72	28.54	28.56	29.84
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[15]	3.62	4.30	4.30	4.33	4.75	4.78	4.93	5.14	5.29	5.35
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**38.28**	**43.77**	**43.74**	**43.70**	**49.79**	**49.82**	**49.41**	**53.43**	**53.46**	**52.66**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Total Energy Consumption										
Distillate Fuel	8.37	9.90	9.71	9.60	11.45	11.18	10.98	12.23	11.94	11.68
Kerosene	0.11	0.14	0.10	0.09	0.14	0.10	0.10	0.13	0.10	0.09
Jet Fuel[9]	3.26	4.04	4.00	3.97	4.74	4.70	4.66	4.89	4.85	4.81
Liquefied Petroleum Gas	2.75	3.03	2.98	2.94	3.42	3.34	3.25	3.60	3.48	3.34
Motor Gasoline[2]	16.98	19.49	19.08	18.74	22.70	22.22	21.33	24.45	23.87	22.66
Petrochemical Feedstock	1.32	1.48	1.48	1.47	1.55	1.55	1.52	1.57	1.57	1.52
Residual Fuel	1.77	1.84	1.74	1.70	2.01	1.87	1.76	2.02	1.92	1.79
Other Petroleum[12]	4.52	4.93	4.89	4.85	5.30	5.25	5.05	5.53	5.48	5.24
Petroleum Subtotal	39.09	44.84	43.98	43.37	51.30	50.22	48.66	54.42	53.21	51.13
Natural Gas	20.74	24.21	24.36	24.29	28.59	29.00	28.02	29.32	29.54	27.24
Lease and Plant Fuel[6]	1.15	1.20	1.22	1.26	1.32	1.37	1.45	1.31	1.32	1.41
Pipeline Natural Gas	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Natural Gas Subtotal	22.54	26.11	26.29	26.26	30.73	31.21	30.31	31.47	31.71	29.48
Metallurgical Coal	0.67	0.55	0.55	0.55	0.42	0.42	0.42	0.37	0.37	0.37
Steam Coal	21.99	24.34	24.30	24.42	26.80	26.84	28.42	30.07	30.08	33.42
Net Coal Coke Imports	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Coal Subtotal	22.71	24.95	24.91	25.02	27.27	27.31	28.89	30.48	30.50	33.83
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[16]	5.89	6.85	6.85	6.88	7.57	7.61	7.76	8.10	8.27	8.32
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.03	0.03	0.03	0.05	0.05	0.06	0.04	0.04	0.04
Total	**98.22**	**111.27**	**110.55**	**110.05**	**125.60**	**125.07**	**124.34**	**133.18**	**132.40**	**131.46**
Energy Use and Related Statistics										
Delivered Energy Use	71.82	81.39	80.69	80.21	92.23	91.68	91.31	97.56	96.76	96.56
Total Energy Use	98.22	111.27	110.55	110.05	125.60	125.07	124.34	133.18	132.40	131.46
Population (millions)	291.39	310.12	310.12	310.12	336.99	336.99	336.99	350.64	350.64	350.64
Gross Domestic Product (billion 2000 dollars)	10381	13084	13063	13031	17634	17641	17619	20292	20293	20260
Carbon Dioxide Emissions (million metric tons)	5788.7	6626.8	6561.1	6527.8	7519.6	7460.6	7448.5	8062.3	7981.1	8028.7

[1]Includes wood used for residential heating. See Table C4 and/or Table C17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Residential	**15.81**	**14.33**	**14.58**	**14.85**	**15.64**	**15.78**	**16.13**	**16.13**	**16.36**	**16.98**
Primary Energy[1]	9.68	8.35	8.61	8.89	9.21	9.32	9.72	9.62	9.86	10.62
Petroleum Products[2]	11.27	10.44	11.81	13.00	11.36	12.57	14.49	11.93	13.13	15.68
Distillate Fuel	9.57	8.29	9.35	10.39	8.85	9.79	11.48	9.12	10.13	12.07
Liquefied Petroleum Gas	14.58	14.25	15.73	17.07	15.06	16.34	18.17	15.65	16.77	19.49
Natural Gas	9.22	7.79	7.83	7.93	8.66	8.57	8.74	9.07	9.14	9.65
Electricity	25.42	22.96	22.99	23.16	24.12	24.16	24.25	24.24	24.32	24.50
Commercial	**15.63**	**13.76**	**13.92**	**14.17**	**15.70**	**15.81**	**16.14**	**16.20**	**16.39**	**17.09**
Primary Energy[1]	7.92	6.81	7.04	7.32	7.54	7.65	8.05	7.82	8.05	8.77
Petroleum Products[2]	8.03	7.13	8.27	9.40	7.55	8.57	10.23	7.84	8.92	10.99
Distillate Fuel	7.03	6.30	7.38	8.45	6.76	7.70	9.26	7.06	8.10	9.98
Residual Fuel	4.96	4.26	5.00	5.93	4.81	5.40	7.06	5.08	5.60	7.62
Natural Gas	8.08	6.87	6.90	7.01	7.68	7.59	7.76	7.96	8.01	8.48
Electricity	23.24	19.93	19.97	20.17	22.10	22.19	22.42	22.40	22.55	23.13
Industrial[3]	**7.78**	**6.85**	**7.31**	**7.78**	**7.75**	**8.10**	**8.51**	**8.13**	**8.49**	**8.99**
Primary Energy	6.49	5.55	6.08	6.63	6.27	6.67	7.18	6.64	7.04	7.68
Petroleum Products[2]	8.29	7.24	8.34	9.42	7.88	8.75	10.37	8.36	9.17	11.29
Distillate Fuel	7.24	6.78	7.85	8.90	7.37	8.31	9.80	7.73	8.77	10.61
Liquefied Petroleum Gas	12.57	10.02	11.46	12.72	10.74	11.97	13.72	11.35	12.45	14.91
Residual Fuel	4.59	3.87	4.64	5.59	4.34	5.00	6.66	4.62	5.19	7.22
Natural Gas[4]	5.56	4.37	4.37	4.48	5.23	5.18	5.34	5.47	5.50	5.97
Metallurgical Coal	1.85	1.82	1.82	1.82	1.75	1.75	1.76	1.68	1.68	1.69
Steam Coal	1.55	1.56	1.57	1.55	1.56	1.58	1.45	1.60	1.61	1.56
Electricity	15.03	13.84	13.84	13.95	15.47	15.51	15.63	15.75	15.83	16.07
Transportation	**11.46**	**10.95**	**11.99**	**13.20**	**11.16**	**12.05**	**13.73**	**11.46**	**12.44**	**14.63**
Primary Energy	11.43	10.93	11.97	13.18	11.13	12.03	13.71	11.44	12.42	14.61
Petroleum Products[2]	11.43	10.93	11.97	13.19	11.13	12.04	13.73	11.44	12.43	14.62
Distillate Fuel[5]	10.92	10.76	11.86	12.95	10.66	11.61	13.08	10.85	11.91	13.78
Jet Fuel[6]	6.46	6.25	7.35	8.41	6.58	7.57	9.24	6.93	7.98	10.03
Motor Gasoline[7]	12.93	12.32	13.35	14.69	12.52	13.42	15.24	12.81	13.80	16.23
Residual Fuel	4.49	3.74	4.40	5.36	4.28	4.82	6.51	4.56	5.02	7.09
Liquefied Petroleum Gas[8]	16.65	15.24	16.62	17.87	15.66	16.86	18.24	16.24	17.10	19.55
Natural Gas[9]	9.04	8.56	8.57	8.67	9.45	9.42	9.58	9.69	9.79	10.23
Ethanol (E85)[10]	16.23	17.11	18.05	19.92	17.22	18.31	20.56	18.13	18.74	21.85
Electricity	20.64	18.81	18.85	19.01	19.99	20.02	20.14	19.96	20.07	20.31
Average End-Use Energy	**11.50**	**10.56**	**11.16**	**11.86**	**11.42**	**11.92**	**12.78**	**11.83**	**12.40**	**13.55**
Primary Energy	9.32	8.61	9.33	10.14	9.18	9.76	10.78	9.55	10.21	11.55
Electricity	21.74	19.36	19.38	19.55	21.11	21.15	21.30	21.38	21.47	21.82
Electric Power[11]										
Fossil Fuel Average	2.24	2.06	2.08	2.14	2.45	2.46	2.49	2.46	2.48	2.50
Petroleum Products	5.28	4.55	5.40	6.37	5.10	5.83	7.47	5.42	6.10	8.09
Distillate Fuel	6.48	5.36	6.39	7.42	6.01	6.94	8.48	6.33	7.33	9.13
Residual Fuel	4.79	4.19	4.93	5.87	4.71	5.31	6.98	5.00	5.51	7.55
Natural Gas	5.46	4.27	4.22	4.33	5.20	5.15	5.27	5.44	5.48	5.84
Steam Coal	1.28	1.25	1.26	1.27	1.25	1.25	1.30	1.31	1.31	1.43

Table D3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Average Price to All Users[12]										
Petroleum Products[2]	10.51	9.91	10.98	12.16	10.29	11.21	12.89	10.66	11.62	13.81
Distillate Fuel	9.90	9.53	10.66	11.75	9.79	10.78	12.32	10.03	11.14	13.03
Jet Fuel	6.46	6.25	7.35	8.41	6.58	7.57	9.24	6.93	7.98	10.03
Liquefied Petroleum Gas	13.04	10.99	12.41	13.67	11.74	12.96	14.69	12.34	13.43	15.91
Motor Gasoline[7]	12.93	12.31	13.34	14.68	12.51	13.41	15.23	12.80	13.79	16.22
Residual Fuel	4.66	3.99	4.71	5.66	4.52	5.09	6.77	4.81	5.30	7.34
Natural Gas	6.86	5.52	5.50	5.61	6.30	6.23	6.41	6.59	6.63	7.16
Coal	1.30	1.27	1.28	1.30	1.27	1.27	1.44	1.32	1.33	1.64
Ethanol (E85)[10]	16.23	17.11	18.05	19.92	17.22	18.31	20.56	18.13	18.74	21.85
Electricity	21.74	19.36	19.38	19.55	21.11	21.15	21.30	21.38	21.47	21.82
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)										
Residential	177.17	175.88	175.96	177.88	209.76	209.74	210.86	223.86	224.55	227.83
Commercial	128.15	129.92	130.76	132.61	177.28	177.97	180.17	200.93	202.43	208.29
Industrial	147.11	139.57	147.77	156.12	169.93	177.24	189.83	184.96	192.09	211.34
Transportation	302.59	341.13	367.80	399.87	407.83	433.81	481.55	449.31	479.81	544.99
Total Non-Renewable Expenditures	755.02	786.50	822.30	866.47	964.80	998.76	1062.42	1059.05	1098.88	1192.45
Transportation Renewable Expenditures	0.02	0.03	0.04	0.04	0.07	0.07	0.08	0.08	0.09	0.10
Total Expenditures	**755.04**	**786.54**	**822.34**	**866.51**	**964.87**	**998.83**	**1062.49**	**1059.13**	**1098.96**	**1192.55**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D4. Transportation Sector Key Indicators and Delivered Energy Consumption

Supply, Disposition, and Prices	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Key Indicators										
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500 pounds	2602	3017	2953	2907	3680	3623	3526	4053	3991	3864
Commercial Light Trucks[1]	65	78	78	77	96	96	95	107	107	106
Freight Trucks greater than 10,000 pounds	214	268	268	267	336	338	337	373	375	374
(billion seat miles available)										
Air	932	1152	1143	1138	1455	1455	1455	1520	1520	1520
(billion ton miles traveled)										
Rail	1352	1576	1575	1576	1833	1836	1905	2001	2002	2147
Domestic Shipping	592	649	657	662	706	718	742	733	744	772
Energy Efficiency Indicators										
(miles per gallon)										
New Light-Duty Vehicle[2]	25.1	25.7	25.9	26.2	26.5	26.9	27.5	26.9	27.3	28.2
New Car[2]	29.5	29.7	30.3	30.5	30.6	31.2	31.7	31.0	31.6	32.3
New Light Truck[2]	21.8	22.9	22.8	23.0	24.1	24.2	24.7	24.6	24.9	25.5
Light-Duty Stock[3]	20.0	20.1	20.2	20.3	20.7	20.9	21.2	21.0	21.3	21.7
New Commercial Light Truck[1]	14.6	15.2	15.2	15.3	16.0	16.1	16.4	16.4	16.5	16.9
Stock Commercial Light Truck[1]	14.0	14.7	14.6	14.7	15.5	15.5	15.7	15.9	16.0	16.2
Freight Truck	6.0	6.0	6.0	6.0	6.4	6.4	6.5	6.6	6.6	6.7
(seat miles per gallon)										
Aircraft	55.3	59.2	59.3	59.4	65.2	65.7	66.1	68.5	69.1	69.4
(ton miles per thousand Btu)										
Rail	2.9	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
Domestic Shipping	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode										
(quadrillion Btu)										
Light-Duty Vehicles	15.78	18.45	18.04	17.71	21.85	21.36	20.51	23.69	23.11	21.94
Commercial Light Trucks[1]	0.58	0.67	0.66	0.66	0.78	0.78	0.76	0.84	0.84	0.82
Bus Transportation	0.25	0.26	0.26	0.26	0.27	0.26	0.26	0.27	0.26	0.26
Freight Trucks	4.46	5.56	5.55	5.53	6.60	6.56	6.51	7.10	7.08	6.97
Rail, Passenger	0.12	0.13	0.13	0.13	0.16	0.16	0.16	0.17	0.17	0.17
Rail, Freight	0.47	0.51	0.51	0.51	0.54	0.54	0.56	0.56	0.56	0.60
Shipping, Domestic	0.26	0.28	0.28	0.29	0.30	0.30	0.31	0.31	0.31	0.32
Shipping, International	0.56	0.51	0.51	0.51	0.52	0.52	0.52	0.52	0.52	0.52
Recreational Boats	0.31	0.33	0.33	0.33	0.37	0.37	0.37	0.39	0.39	0.39
Air	2.74	3.43	3.39	3.36	4.11	4.08	4.03	4.25	4.22	4.18
Military Use	0.69	0.80	0.80	0.80	0.82	0.82	0.82	0.83	0.83	0.83
Lubricants	0.20	0.21	0.21	0.21	0.25	0.25	0.25	0.27	0.27	0.27
Pipeline Fuel	0.65	0.70	0.71	0.71	0.82	0.85	0.84	0.84	0.85	0.82
Total	**27.07**	**31.85**	**31.40**	**31.01**	**37.39**	**36.84**	**35.91**	**40.04**	**39.42**	**38.09**
(million barrels per day oil equivalent)										
Light-Duty Vehicles	8.29	9.72	9.50	9.32	11.49	11.23	10.78	12.45	12.15	11.53
Commercial Light Trucks[1]	0.30	0.35	0.35	0.35	0.41	0.41	0.40	0.44	0.44	0.43
Bus Transportation	0.12	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.13	0.12
Freight Trucks	2.13	2.66	2.66	2.65	3.16	3.14	3.12	3.40	3.39	3.34
Rail, Passenger	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Rail, Freight	0.22	0.24	0.24	0.24	0.25	0.26	0.27	0.26	0.26	0.28
Shipping, Domestic	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.14	0.15	0.15
Shipping, International	0.25	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.23	0.23
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Air	1.33	1.66	1.64	1.62	1.99	1.97	1.95	2.06	2.04	2.02
Military Use	0.33	0.39	0.39	0.39	0.40	0.40	0.40	0.40	0.40	0.40
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.33	0.35	0.36	0.36	0.42	0.43	0.43	0.43	0.43	0.42
Total	**13.73**	**16.19**	**15.95**	**15.75**	**19.00**	**18.72**	**18.23**	**20.36**	**20.03**	**19.33**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for #Y!# and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003: Energy Information Administration (EIA), *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004); Federal Highway Administration, *Highway Statistics 2001* (Washington, DC, November 2002); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 2001*, DOE/EIA-0214(2001) (Washington, DC, November 2004) U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2003/2002* (Washington, DC, 2003); EIA, *Fuel Oil and Kerosene Sales 2002*, DOE/EIA-0535(2002) (Washington, DC, November 2003); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D5. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Crude Oil										
Domestic Crude Production[1]	5.68	6.02	6.16	6.23	5.21	5.36	5.77	4.73	4.98	5.30
Alaska	0.97	0.81	0.82	0.84	0.86	0.90	0.96	0.61	0.64	0.72
Lower 48 States	4.71	5.22	5.34	5.38	4.35	4.46	4.80	4.12	4.34	4.58
Net Imports	9.65	11.31	11.13	10.93	14.80	14.62	13.39	16.11	15.83	14.30
Gross Imports	9.66	11.32	11.14	10.94	14.81	14.63	13.41	16.12	15.84	14.31
Exports	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other Crude Supply[2]	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.31**	**17.33**	**17.29**	**17.16**	**20.01**	**19.98**	**19.16**	**20.84**	**20.81**	**19.60**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.72	1.96	1.99	2.04	2.04	2.08	2.18	2.04	2.07	2.17
Net Product Imports	1.58	2.06	1.48	1.11	2.31	1.59	0.66	3.00	2.19	0.94
Gross Refined Product Imports[3]	1.85	1.99	1.38	1.02	1.90	1.15	0.38	2.47	1.63	0.56
Unfinished Oil Imports	0.34	0.59	0.61	0.59	0.91	0.93	0.77	1.02	1.04	0.87
Blending Components	0.41	0.48	0.47	0.46	0.55	0.54	0.52	0.60	0.58	0.55
Exports	1.01	0.99	0.98	0.96	1.05	1.03	1.01	1.08	1.06	1.04
Refinery Processing Gain[4]	1.00	1.11	1.12	1.14	1.50	1.53	1.51	1.56	1.61	1.57
Other Supply[5]	0.69	0.53	0.67	0.78	0.46	0.57	1.43	0.50	0.62	1.93
Total Primary Supply[6]	**20.30**	**22.98**	**22.54**	**22.22**	**26.32**	**25.76**	**24.95**	**27.93**	**27.30**	**26.22**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	8.93	10.28	10.06	9.89	11.97	11.71	11.25	12.89	12.59	11.94
Jet Fuel[8]	1.57	1.95	1.93	1.92	2.29	2.27	2.25	2.36	2.34	2.32
Distillate Fuel[9]	3.95	4.70	4.61	4.56	5.44	5.31	5.22	5.81	5.67	5.55
Residual Fuel	0.77	0.80	0.76	0.74	0.88	0.82	0.77	0.88	0.84	0.78
Other[10]	4.77	5.25	5.18	5.12	5.74	5.65	5.47	5.98	5.86	5.62
Total	**20.00**	**22.98**	**22.54**	**22.22**	**26.32**	**25.76**	**24.96**	**27.93**	**27.30**	**26.22**
Refined Petroleum Products Supplied										
Residential and Commercial	1.28	1.33	1.23	1.17	1.41	1.29	1.18	1.42	1.30	1.15
Industrial[11]	4.87	5.33	5.28	5.23	5.81	5.75	5.58	6.05	5.96	5.74
Transportation	13.35	15.76	15.52	15.31	18.48	18.18	17.69	19.82	19.48	18.80
Electric Power[12]	0.50	0.56	0.52	0.51	0.62	0.54	0.51	0.64	0.57	0.53
Total	**20.00**	**22.98**	**22.54**	**22.22**	**26.32**	**25.76**	**24.96**	**27.93**	**27.30**	**26.22**
Discrepancy[13]	**0.29**	**-0.00**	**0.00**	**-0.00**	**0.00**	**-0.01**	**-0.01**	**-0.00**	**0.00**	**-0.00**
World Oil Price (2003 dollars per barrel)[14]	27.73	25.00	30.99	37.00	28.50	33.67	44.33	30.31	35.00	48.00
Import Share of Product Supplied	0.56	0.58	0.56	0.54	0.65	0.63	0.56	0.68	0.66	0.58
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2003 dollars)	113.78	125.14	145.87	165.06	180.07	200.57	226.90	215.89	233.46	267.39
Domestic Refinery Distillation Capacity[15]	16.8	18.7	18.7	18.6	21.4	21.4	20.6	22.3	22.2	21.0
Capacity Utilization Rate (percent)	93.0	94.0	93.8	93.4	94.8	94.8	94.5	94.9	94.9	94.8

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers; natural gas converted to liquid fuel; and coal converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Average refiner acquisition cost for imported crude oil.
[15]End-of-year operable capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2003 data: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Table D6. Petroleum Product Prices
(2003 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
World Oil Price (2003 dollars per barrel)	27.73	25.00	30.99	37.00	28.50	33.67	44.33	30.31	35.00	48.00
Delivered Sector Product Prices										
Residential										
Distillate Fuel	132.7	114.9	129.7	144.1	122.7	135.8	159.2	126.4	140.5	167.4
Liquefied Petroleum Gas	125.4	122.6	135.3	146.8	129.5	140.6	156.3	134.6	144.2	167.7
Commercial										
Distillate Fuel	97.3	86.9	101.8	116.5	93.2	106.2	127.7	97.3	111.7	137.6
Residual Fuel	74.3	63.7	74.8	88.8	71.9	80.8	105.6	76.0	83.9	114.1
Residual Fuel (2003 dollars per barrel)	31.21	26.77	31.42	37.30	30.21	33.93	44.36	31.92	35.22	47.91
Industrial[1]										
Distillate Fuel	100.2	93.3	107.9	122.5	101.2	114.1	134.5	106.2	120.4	145.7
Liquefied Petroleum Gas	108.1	86.1	98.5	109.4	92.3	102.9	118.0	97.6	107.1	128.3
Residual Fuel	68.7	57.9	69.5	83.7	64.9	74.8	99.7	69.1	77.7	108.0
Residual Fuel (2003 dollars per barrel)	28.84	24.33	29.20	35.14	27.27	31.41	41.85	29.02	32.64	45.37
Transportation										
Diesel Fuel (distillate)[2]	150.4	147.5	162.6	177.5	146.1	159.1	179.2	148.6	163.2	188.8
Jet Fuel[3]	87.2	84.3	99.3	113.5	88.8	102.2	124.8	93.5	107.7	135.4
Motor Gasoline[4]	160.3	152.4	165.2	181.7	154.9	166.1	188.6	158.5	170.7	200.8
Liquid Petroleum Gas	143.2	131.1	142.9	153.7	134.7	145.0	156.8	139.7	147.0	168.1
Residual Fuel	67.3	56.0	65.9	80.2	64.1	72.1	97.5	68.3	75.2	106.1
Residual Fuel (2003 dollars per barrel)	28.25	23.50	27.69	33.70	26.92	30.28	40.93	28.68	31.58	44.58
Ethanol (E85)[5]	152.4	160.5	169.4	186.9	161.6	171.9	192.9	170.1	175.9	205.0
Electric Power[6]										
Distillate Fuel	89.8	74.4	88.6	102.9	83.3	96.3	117.5	87.8	101.7	126.7
Residual Fuel	71.7	62.7	73.7	87.9	70.5	79.4	104.5	74.9	82.5	112.9
Residual Fuel (2003 dollars per barrel)	30.12	26.32	30.97	36.92	29.63	33.36	43.88	31.45	34.64	47.44
Refined Petroleum Product Prices[7]										
Distillate Fuel	136.7	131.0	146.5	161.5	134.4	147.9	169.1	137.7	152.9	178.8
Jet Fuel[3]	87.2	84.3	99.3	113.5	88.8	102.2	124.8	93.5	107.7	135.4
Liquefied Petroleum Gas	112.1	94.5	106.7	117.6	101.0	111.5	126.4	106.1	115.5	136.8
Motor Gasoline[4]	160.3	152.2	165.0	181.5	154.8	165.9	188.5	158.4	170.6	200.7
Residual Fuel	69.8	59.8	70.5	84.7	67.7	76.2	101.3	72.0	79.3	109.8
Residual Fuel (2003 dollars per barrel)	29.32	25.11	29.60	35.56	28.43	32.02	42.54	30.22	33.31	46.12
Average	**136.6**	**128.3**	**141.8**	**156.8**	**132.4**	**144.2**	**165.3**	**136.8**	**149.3**	**176.9**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2003 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2003 world oil price: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

October Futures and High B Oil Price Case Comparisons

Table D7. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
World Oil Price (2003 dollars per barrel)[1]	**27.73**	**25.00**	**30.99**	**37.00**	**28.50**	**33.67**	**44.33**	**30.31**	**35.00**	**48.00**
Production (Conventional)[2]										
Industrialized Countries										
U.S. (50 states)	9.09	9.61	9.93	10.07	9.21	9.55	10.12	8.82	9.28	9.79
Canada	2.25	1.83	1.85	1.90	1.60	1.62	1.71	1.57	1.59	1.69
Mexico	3.80	4.21	4.28	4.47	4.62	4.70	5.05	4.85	4.92	5.35
Western Europe[3]	6.69	6.35	6.41	6.66	5.51	5.56	5.90	5.00	5.04	5.40
Japan	0.13	0.08	0.09	0.10	0.06	0.07	0.09	0.06	0.07	0.09
Australia and New Zealand	0.66	0.96	0.97	1.01	0.89	0.90	0.95	0.86	0.87	0.93
Total Industrialized	**22.62**	**23.05**	**23.54**	**24.20**	**21.89**	**22.40**	**23.83**	**21.16**	**21.77**	**23.26**
Eurasia										
Former Soviet Union										
Russia	8.34	9.98	10.16	10.66	10.90	11.09	12.02	11.11	11.29	12.38
Caspian Area[4]	1.87	3.14	3.20	3.37	5.23	5.33	5.82	6.22	6.32	7.00
Eastern Europe[5]	0.22	0.33	0.34	0.35	0.41	0.42	0.44	0.45	0.46	0.49
Total Eurasia	**10.44**	**13.46**	**13.70**	**14.38**	**16.54**	**16.84**	**18.28**	**17.78**	**18.07**	**19.86**
Developing Countries										
OPEC[6]										
Asia	1.38	1.47	1.31	1.11	1.51	1.35	0.98	1.56	1.41	0.98
Middle East	20.95	24.45	21.74	18.46	32.37	28.88	20.87	38.47	34.76	24.21
North Africa	2.99	3.44	3.06	2.60	4.44	3.96	2.86	4.78	4.32	3.01
West Africa	1.98	2.36	2.10	1.78	3.13	2.79	2.02	3.74	3.38	2.36
South America	2.85	3.34	2.97	2.52	4.44	3.96	2.86	5.20	4.70	3.27
Non-OPEC										
China	3.10	3.64	3.70	3.82	3.49	3.55	3.76	3.41	3.47	3.70
Other Asia	2.59	2.65	2.70	2.80	2.71	2.76	2.94	2.64	2.69	2.89
Middle East[7]	1.81	2.24	2.28	2.35	2.57	2.62	2.77	2.78	2.83	3.02
Africa	2.94	3.75	3.82	4.05	5.44	5.54	6.10	6.56	6.67	7.45
South and Central America	3.93	4.53	4.61	4.86	5.91	6.02	6.57	6.42	6.52	7.22
Total Developing Countries	**44.52**	**51.87**	**48.28**	**44.36**	**66.02**	**61.44**	**51.72**	**75.57**	**70.74**	**58.10**
Total Production (Conventional)	**77.58**	**88.38**	**85.51**	**82.95**	**104.45**	**100.68**	**93.83**	**114.51**	**110.58**	**101.22**
Production[6] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.12	0.00	0.00	0.77	0.00	0.00	1.19
Other North America	0.93	1.73	1.74	2.12	3.33	3.34	4.20	3.46	3.47	4.69
Western Europe	0.04	0.04	0.05	0.05	0.05	0.06	0.07	0.05	0.07	0.08
Asia	0.03	0.04	0.04	0.08	0.05	0.07	0.16	0.07	0.09	0.20
Middle East[7]	0.03	0.12	0.13	0.19	0.21	0.25	0.44	0.25	0.30	0.56
Africa	0.21	0.23	0.23	0.33	0.28	0.29	0.57	0.32	0.33	0.68
South and Central America	0.57	0.82	0.84	1.38	1.48	1.51	2.53	1.50	1.54	2.99
Total Production (Nonconventional)	**1.79**	**2.98**	**3.03**	**4.28**	**5.40**	**5.52**	**8.75**	**5.65**	**5.80**	**10.39**
Total Production	**79.37**	**91.35**	**88.54**	**87.23**	**109.85**	**106.20**	**102.59**	**120.17**	**116.39**	**111.62**

Table D7. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2003	Projections								
		2010			2020			2025		
		Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price	Reference	October Futures	High B World Oil Price
Consumption[8]										
Industrialized Countries										
U.S. (50 states)	20.00	22.98	22.54	22.22	26.32	25.76	24.96	27.93	27.30	26.22
U.S. Territories	0.36	0.38	0.35	0.34	0.43	0.40	0.36	0.47	0.44	0.39
Canada	2.17	2.30	2.15	2.08	2.62	2.45	2.24	2.80	2.64	2.37
Mexico	2.02	2.36	2.23	2.18	2.88	2.57	2.31	3.48	3.05	2.62
Western Europe[3]	14.22	14.72	14.25	14.01	15.45	15.00	14.40	15.71	15.31	14.59
Japan	5.58	5.70	5.29	5.14	5.69	5.10	4.54	5.84	5.23	4.48
Australia and New Zealand	1.04	1.27	1.23	1.22	1.54	1.50	1.45	1.69	1.65	1.58
Total Industrialized	**45.38**	**49.72**	**48.05**	**47.18**	**54.93**	**52.78**	**50.26**	**57.92**	**55.63**	**52.26**
Eurasia										
Former Soviet Union	4.18	4.39	4.27	4.21	5.74	5.61	5.43	6.45	6.32	6.08
Eastern Europe[5]	1.42	1.56	1.53	1.52	1.89	1.86	1.83	2.09	2.06	2.01
Total Eurasia	**5.59**	**5.95**	**5.81**	**5.73**	**7.63**	**7.47**	**7.25**	**8.54**	**8.38**	**8.10**
Developing Countries										
China	5.54	7.63	7.29	7.12	11.06	10.63	10.05	12.79	12.35	11.56
India	2.19	2.79	2.68	2.64	4.37	4.15	3.92	5.29	5.04	4.68
South Korea	2.17	2.51	2.39	2.34	2.75	2.61	2.44	2.93	2.79	2.57
Other Asia	5.74	7.28	7.12	7.04	9.47	9.28	9.02	10.66	10.47	10.13
Middle East[7]	5.58	6.83	6.74	6.69	8.34	8.25	8.12	9.08	8.99	8.82
Africa	2.72	3.13	3.06	3.04	4.13	4.03	3.91	4.66	4.55	4.38
South and Central America	4.69	5.81	5.70	5.64	7.48	7.36	7.18	8.61	8.48	8.25
Total Developing Countries	**28.64**	**35.98**	**34.99**	**34.50**	**47.59**	**46.30**	**44.64**	**54.01**	**52.68**	**50.40**
Total Consumption	**79.60**	**91.65**	**88.84**	**87.41**	**110.14**	**106.54**	**102.15**	**120.47**	**116.69**	**110.76**
OPEC Production[10]	30.60	35.79	31.93	27.70	47.21	42.33	31.92	55.13	50.03	36.63
Non-OPEC Production[10]	48.77	55.56	56.61	59.53	62.64	63.87	70.67	65.04	66.36	74.98
Net Eurasia Exports	4.84	7.51	7.89	8.65	8.92	9.37	11.03	9.25	9.68	11.77
OPEC Market Share	0.39	0.39	0.36	0.32	0.43	0.40	0.31	0.46	0.43	0.33

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates, natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2005 National Energy Modeling System runs AEO2005.D102004A, CF2005.D111104A, and VHW2005.D120304A.

Appendix E

Results from Side Cases

Table E1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2003	2010				2015			
		2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.96	0.91	0.90	0.89	0.87	0.89	0.88	0.87	0.82
Kerosene	0.07	0.10	0.09	0.09	0.09	0.10	0.09	0.09	0.08
Liquefied Petroleum Gas	0.54	0.58	0.57	0.57	0.54	0.62	0.61	0.60	0.55
Petroleum Subtotal	1.58	1.58	1.56	1.55	1.50	1.60	1.58	1.55	1.45
Natural Gas	5.25	5.76	5.69	5.66	5.30	6.03	5.90	5.75	4.92
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy	0.40	0.41	0.40	0.39	0.39	0.41	0.39	0.38	0.38
Electricity	4.37	5.06	5.02	4.96	4.70	5.49	5.40	5.27	4.74
Delivered Energy	**11.61**	**12.82**	**12.67**	**12.57**	**11.89**	**13.55**	**13.29**	**12.97**	**11.49**
Electricity Related Losses	9.71	10.88	10.80	10.67	10.11	11.48	11.29	11.01	9.89
Total	**21.31**	**23.70**	**23.47**	**23.24**	**22.00**	**25.03**	**24.58**	**23.97**	**21.38**
Delivered Energy Intensity (million Btu per household)	**103.6**	**105.0**	**103.8**	**103.0**	**97.4**	**105.0**	**102.9**	**100.4**	**89.0**
Non-Marketed Renewables Consumption (quadrillion Btu)	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.05**	**0.04**
Commercial									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.52	0.62	0.62	0.61	0.62	0.70	0.66	0.65	0.69
Residual Fuel	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.86	0.86	0.85	0.86	0.95	0.91	0.90	0.93
Natural Gas	3.22	3.49	3.49	3.48	3.42	3.67	3.69	3.68	3.54
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	5.04	5.00	4.94	4.59	5.75	5.63	5.49	4.90
Delivered Energy	**8.29**	**9.57**	**9.53**	**9.46**	**9.05**	**10.54**	**10.41**	**10.25**	**9.56**
Electricity Related Losses	9.18	10.85	10.76	10.64	9.87	12.00	11.77	11.47	10.24
Total	**17.46**	**20.42**	**20.29**	**20.10**	**18.91**	**22.54**	**22.18**	**21.72**	**19.80**
Delivered Energy Intensity (thousand Btu per square foot)	**114.8**	**117.8**	**117.3**	**116.5**	**111.3**	**119.2**	**117.8**	**115.9**	**108.1**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	660	673	677	677	677	698	722	722	722
Solar Photovoltaic	48	258	258	258	268	284	304	358	618
Electricity Generation (billion kilowatthours)									
Natural Gas	4.75	4.85	4.87	4.87	4.87	5.02	5.20	5.20	5.20
Solar Photovoltaic	0.10	0.55	0.55	0.55	0.57	0.60	0.64	0.76	1.31
Non-Marketed Renewables Consumption (quadrillion Btu)	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2005 National Energy Modeling System, runs BLDFRZN.D102104A, BLDDEF.D102104A, BLDHIGH.D110404A, and BLDBEST.D102104A.

2020				2025				Annual Growth 2003-2025 (percent)			
2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology
0.86	0.83	0.81	0.75	0.82	0.77	0.74	0.67	-0.7%	-1.0%	-1.2%	-1.6%
0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.07	1.0%	0.8%	0.7%	-0.4%
0.66	0.64	0.62	0.56	0.69	0.67	0.63	0.57	1.1%	0.9%	0.7%	0.2%
1.61	1.56	1.52	1.38	1.61	1.53	1.46	1.30	0.1%	-0.1%	-0.3%	-0.9%
6.25	6.05	5.78	4.71	6.44	6.17	5.78	4.60	0.9%	0.7%	0.4%	-0.6%
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.4%	-1.0%	-1.1%	-1.3%
0.42	0.39	0.37	0.36	0.42	0.38	0.36	0.35	0.2%	-0.3%	-0.5%	-0.6%
5.92	5.79	5.59	4.83	6.39	6.18	5.96	5.09	1.7%	1.6%	1.4%	0.7%
14.21	**13.80**	**13.28**	**11.29**	**14.86**	**14.26**	**13.57**	**11.35**	**1.1%**	**0.9%**	**0.7%**	**-0.1%**
12.03	11.77	11.36	9.82	12.77	12.35	11.92	10.18	1.3%	1.1%	0.9%	0.2%
26.24	**25.56**	**24.64**	**21.10**	**27.63**	**26.62**	**25.50**	**21.53**	**1.2%**	**1.0%**	**0.8%**	**0.0%**
104.6	**101.6**	**97.8**	**83.1**	**104.3**	**100.1**	**95.3**	**79.7**	**0.0%**	**-0.2%**	**-0.4%**	**-1.2%**
0.04	**0.04**	**0.07**	**0.06**	**0.05**	**0.05**	**0.09**	**0.09**	**3.3%**	**3.3%**	**6.4%**	**5.9%**
0.78	0.71	0.70	0.76	0.88	0.77	0.74	0.84	2.4%	1.8%	1.6%	2.2%
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.2%	0.2%	0.2%	0.2%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.5%	0.5%	0.5%	0.5%
0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.5%	0.5%	0.5%	0.5%
0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.2%	0.2%	0.2%	0.2%
1.03	0.96	0.94	1.01	1.13	1.02	0.99	1.09	1.8%	1.4%	1.3%	1.7%
3.86	3.91	3.89	3.70	4.08	4.17	4.14	3.92	1.1%	1.2%	1.2%	0.9%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	-0.1%	-0.1%	-0.1%	-0.1%
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.0%	0.0%	0.0%	0.0%
6.54	6.33	6.09	5.34	7.45	7.13	6.77	5.88	2.7%	2.5%	2.3%	1.6%
11.61	**11.38**	**11.11**	**10.23**	**12.84**	**12.49**	**12.09**	**11.07**	**2.0%**	**1.9%**	**1.7%**	**1.3%**
13.29	12.87	12.38	10.85	14.91	14.25	13.54	11.75	2.2%	2.0%	1.8%	1.1%
24.90	**24.24**	**23.49**	**21.08**	**27.76**	**26.74**	**25.63**	**22.83**	**2.1%**	**2.0%**	**1.8%**	**1.2%**
120.7	**118.3**	**115.5**	**106.3**	**122.6**	**119.2**	**115.4**	**105.7**	**0.3%**	**0.2%**	**0.0%**	**-0.4%**
737	909	909	931	782	1359	1418	1812	0.8%	3.3%	3.5%	4.7%
341	639	766	1672	497	1468	1786	3161	11.2%	16.8%	17.9%	21.0%
5.30	6.57	6.57	6.72	5.63	9.84	10.26	13.13	0.8%	3.4%	3.6%	4.7%
0.72	1.34	1.62	3.44	1.04	3.05	3.69	6.45	11.1%	16.7%	17.7%	20.8%
0.03	**0.03**	**0.03**	**0.04**	**0.03**	**0.04**	**0.04**	**0.05**	**1.1%**	**2.1%**	**2.3%**	**3.3%**

Table E2. Key Results for Industrial Sector Technology Cases

Consumption	2003	2010			2020			2025		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Value of Shipments (billion 1996 dollars)										
Manufacturing	3851	4836	4836	4836	6046	6046	6046	6733	6733	6733
Nonmanufacturing	1254	1329	1329	1329	1587	1587	1587	1736	1736	1736
Total	**5105**	**6165**	**6165**	**6165**	**7633**	**7633**	**7633**	8469	8469	8469
Energy Consumption (quadrillion Btu)[1]										
Distillate Fuel	1.03	1.09	1.04	1.01	1.24	1.14	1.04	1.32	1.19	1.07
Liquefied Petroleum Gas	2.09	2.37	2.30	2.25	2.74	2.59	2.45	2.90	2.74	2.58
Petrochemical Feedstocks	1.32	1.53	1.48	1.45	1.65	1.55	1.46	1.68	1.57	1.48
Residual Fuel	0.28	0.35	0.34	0.33	0.41	0.38	0.35	0.41	0.38	0.34
Motor Gasoline	0.31	0.32	0.31	0.31	0.37	0.35	0.33	0.39	0.37	0.35
Petroleum Coke	1.00	1.10	1.07	1.04	1.37	1.30	1.24	1.45	1.38	1.31
Still Gas	1.48	1.77	1.77	1.77	1.65	1.65	1.65	1.67	1.68	1.67
Asphalt and Road Oil	1.22	1.25	1.16	1.09	1.52	1.30	1.11	1.69	1.43	1.20
Miscellaneous Petroleum[2]	0.61	0.72	0.69	0.67	0.83	0.77	0.70	0.82	0.75	0.67
Petroleum Subtotal	9.31	10.50	10.17	9.92	11.77	11.03	10.32	12.34	11.47	10.67
Natural Gas	7.19	8.42	8.10	7.89	9.52	8.89	8.20	9.96	9.26	8.38
Lease and Plant Fuel[3]	1.15	1.20	1.20	1.20	1.32	1.32	1.32	1.31	1.31	1.31
Natural Gas Subtotal	8.34	9.63	9.31	9.10	10.85	10.21	9.52	11.27	10.57	9.69
Metallurgical Coal and Coke[4]	0.72	0.67	0.61	0.51	0.60	0.47	0.30	0.57	0.42	0.24
Steam Coal	1.39	1.45	1.42	1.40	1.48	1.42	1.35	1.49	1.42	1.34
Coal Subtotal	2.11	2.12	2.03	1.91	2.08	1.89	1.65	2.06	1.83	1.57
Renewable Energy[5]	1.79	2.06	2.07	2.16	2.32	2.34	2.65	2.46	2.50	2.94
Purchased Electricity	3.31	3.86	3.78	3.67	4.43	4.19	3.95	4.71	4.39	4.08
Delivered Energy	**24.86**	**28.17**	**27.35**	**26.76**	**31.45**	**29.66**	**28.09**	**32.84**	**30.76**	**28.95**
Electricity Related Losses	7.35	8.30	8.13	7.90	9.01	8.52	8.03	9.42	8.78	8.16
Total	**32.21**	**36.47**	**35.47**	**34.67**	**40.46**	**38.19**	**36.12**	**42.26**	**39.53**	**37.11**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 1996 dollar)	**4.87**	**4.57**	**4.44**	**4.34**	**4.12**	**3.89**	**3.68**	**3.88**	**3.63**	**3.42**
Industrial Combined Heat and Power										
Capacity (gigawatts)	24.87	29.59	29.50	30.85	35.70	36.03	39.04	38.94	40.09	43.44
Generation (billion kilowatthours)	139.59	172.52	171.71	180.51	219.14	220.64	238.77	243.22	250.10	268.85

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2005 National Energy Modeling System runs INDFRZN.D102304A, AEO2005.D102004A, and INDHIGH.D102304A.

Table E3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2003	2010			2020			2025		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500	2601	3015	3016	3020	3661	3680	3704	4017	4052	4092
Commercial Light Trucks[1]	64	78	78	78	96	96	96	106	107	107
Freight Trucks greater than 10,000	214	268	268	269	337	337	337	374	374	374
(billion seat miles available)										
Air	932	1152	1152	1152	1455	1455	1455	1520	1520	1520
(billion ton miles traveled)										
Rail	1354	1579	1579	1579	1836	1836	1837	2005	2005	2006
Domestic Shipping	592	650	650	650	707	707	707	734	734	734
Energy Efficiency Indicators										
(miles per gallon)										
New Light-Duty Vehicle[2]	25.1	25.2	25.7	26.5	25.0	26.5	28.2	24.9	26.9	28.8
New Car[2]	29.5	29.1	29.7	31.3	29.1	30.6	32.8	29.0	31.0	33.4
New Light Truck[2]	21.8	22.5	22.9	23.3	22.6	24.1	25.5	22.7	24.6	26.3
Light-Duty Stock[3]	19.9	20.1	20.1	20.3	20.1	20.7	21.5	20.1	21.0	22.1
New Commercial Light Truck[1]	14.6	15.0	15.2	15.5	14.9	16.0	17.0	14.8	16.4	17.6
Stock Commercial Light Truck[1]	14.0	14.6	14.7	14.7	14.9	15.5	16.1	14.9	15.9	16.8
Freight Truck	6.0	6.0	6.0	6.1	6.1	6.4	6.4	6.1	6.6	6.6
(seat miles per gallon)										
Aircraft	55.3	58.7	59.2	60.7	59.8	65.2	73.7	59.7	68.5	82.4
(ton miles per thousand Btu)										
Rail	2.9	2.9	3.1	3.2	2.9	3.4	3.8	2.9	3.6	4.1
Domestic Shipping	2.3	2.3	2.3	2.4	2.3	2.4	2.5	2.3	2.4	2.6
Energy Use by Mode										
(quadrillion Btu)										
Light-Duty Vehicles	15.77	18.48	18.42	18.28	22.35	21.81	21.14	24.59	23.65	22.67
Commercial Light Trucks[1]	0.58	0.67	0.66	0.66	0.81	0.78	0.75	0.90	0.84	0.80
Bus Transportation	0.25	0.26	0.26	0.26	0.28	0.27	0.27	0.29	0.27	0.27
Freight Trucks	4.47	5.56	5.56	5.53	6.95	6.61	6.54	7.69	7.11	7.04
Rail, Passenger	0.12	0.13	0.13	0.14	0.14	0.16	0.17	0.14	0.17	0.20
Rail, Freight	0.47	0.54	0.51	0.49	0.62	0.54	0.49	0.68	0.56	0.49
Shipping, Domestic	0.26	0.28	0.28	0.28	0.31	0.30	0.29	0.32	0.31	0.29
Shipping, International	0.56	0.51	0.51	0.51	0.52	0.52	0.52	0.53	0.52	0.52
Recreational Boats	0.31	0.33	0.33	0.33	0.37	0.37	0.37	0.39	0.39	0.39
Air	2.74	3.45	3.43	3.34	4.48	4.11	3.64	4.88	4.25	3.54
Military Use	0.69	0.80	0.80	0.80	0.82	0.82	0.82	0.83	0.83	0.83
Lubricants	0.20	0.21	0.21	0.21	0.25	0.25	0.25	0.27	0.27	0.27
Pipeline Fuel	0.65	0.70	0.70	0.70	0.82	0.82	0.82	0.84	0.84	0.84
Total	**27.07**	**31.93**	**31.82**	**31.54**	**38.72**	**37.35**	**36.07**	**42.36**	**40.01**	**38.15**
Energy Use by Fuel										
(quadrillion Btu)										
Distillate Fuel[4]	5.54	6.98	6.95	6.89	8.78	8.36	8.19	9.77	9.06	8.85
Jet Fuel[5]	3.26	4.06	4.04	3.95	5.11	4.74	4.27	5.52	4.89	4.18
Motor Gasoline[6]	16.64	19.17	19.12	18.98	22.86	22.27	21.63	25.02	24.00	23.07
Residual Fuel	0.62	0.57	0.56	0.56	0.58	0.58	0.57	0.59	0.58	0.57
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.08
Other Petroleum[7]	0.24	0.26	0.26	0.26	0.29	0.29	0.29	0.31	0.31	0.31
Petroleum Subtotal	26.31	31.09	30.98	30.69	37.70	36.32	35.03	41.30	38.93	37.06
Pipeline Fuel Natural Gas	0.65	0.70	0.70	0.70	0.82	0.82	0.82	0.84	0.84	0.84
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.10	0.10	0.09	0.11	0.11	0.10
Renewable Energy (E85)[8]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.09	0.11	0.12	0.10	0.12	0.14
Delivered Energy	**27.07**	**31.93**	**31.82**	**31.54**	**38.72**	**37.35**	**36.07**	**42.36**	**40.01**	**38.15**
Electricity Related Losses	0.17	0.18	0.19	0.20	0.19	0.22	0.24	0.20	0.24	0.27
Total	**27.24**	**32.12**	**32.02**	**31.74**	**38.92**	**37.57**	**36.31**	**42.55**	**40.25**	**38.42**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Commercial trucks 8,500 to 10,000 pounds.
[4]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[5]Includes only kerosene type.
[6]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[7]Includes aviation gasoline and lubricants.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LT.D110904A, BASE.D110904A, and HT.D110904A.

Table E4. Key Results for Integrated Technology Cases

Consumption and Emissions	2003	2010			2020			2025		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	21.3	23.6	23.5	23.3	26.1	25.6	24.7	27.5	26.6	25.4
Commercial	17.5	20.3	20.3	20.2	24.7	24.2	23.6	27.5	26.7	25.6
Industrial	32.2	36.4	35.5	34.7	40.4	38.2	36.0	42.3	39.5	36.8
Transportation	27.2	32.1	32.0	31.8	38.9	37.6	36.3	42.6	40.3	38.5
Total	**98.2**	**112.4**	**111.3**	**109.9**	**130.2**	**125.6**	**120.6**	**139.8**	**133.2**	**126.2**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	39.1	45.3	44.8	44.3	53.9	51.3	49.1	58.2	54.4	51.4
Natural Gas	22.5	26.6	26.1	25.6	31.8	30.7	29.2	32.6	31.5	30.5
Coal	22.7	25.1	25.0	24.6	28.1	27.3	25.7	32.2	30.5	26.7
Nuclear Power	8.0	8.5	8.5	8.5	8.7	8.7	8.7	8.7	8.7	8.7
Renewable Energy	5.9	6.9	6.8	6.9	7.7	7.6	7.9	8.2	8.1	8.8
Other	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.0
Total	**98.2**	**112.4**	**111.3**	**109.9**	**130.2**	**125.6**	**120.6**	**139.8**	**133.2**	**126.2**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**9.5**	**8.6**	**8.5**	**8.4**	**7.4**	**7.1**	**6.8**	**6.9**	**6.6**	**6.2**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	1225.0	1361.6	1355.2	1342.1	1524.0	1487.6	1420.8	1645.4	1580.0	1457.9
Commercial	1028.1	1199.5	1197.6	1186.8	1482.0	1443.5	1385.1	1697.3	1627.9	1499.8
Industrial	1663.8	1900.8	1852.3	1800.3	2105.5	1979.6	1830.1	2219.3	2058.6	1847.0
Transportation	1871.9	2226.1	2221.8	2203.8	2703.4	2608.9	2520.1	2957.0	2795.8	2666.6
Total	**5788.7**	**6688.0**	**6626.8**	**6533.0**	**7814.8**	**7519.6**	**7156.2**	**8519.0**	**8062.3**	**7471.3**
Carbon Dioxide Emissions by End-Use Fuel (million metric tons)										
Petroleum	2403.4	2820.4	2800.4	2770.3	3350.7	3219.6	3096.8	3631.1	3420.8	3245.5
Natural Gas	903.1	1024.9	1008.1	999.5	1143.1	1106.1	1052.2	1185.9	1146.3	1078.6
Coal	196.6	207.9	199.8	189.0	203.4	186.3	165.7	201.4	181.1	158.4
Electricity	2285.7	2634.8	2618.6	2574.2	3117.7	3007.6	2841.5	3500.6	3314.1	2988.9
Total	**5788.7**	**6688.0**	**6626.8**	**6533.0**	**7814.8**	**7519.6**	**7156.2**	**8519.0**	**8062.3**	**7471.3**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)										
Petroleum	95.8	98.6	96.3	93.8	136.4	106.9	94.8	135.9	109.2	100.1
Natural Gas	266.6	370.8	362.1	344.9	527.1	508.0	479.1	525.7	506.5	523.4
Coal	1906.0	2145.0	2139.8	2115.6	2432.7	2371.5	2246.7	2816.6	2676.8	2343.9
Other	17.3	20.4	20.4	19.9	21.5	21.2	21.0	22.5	21.5	21.5
Total	**2285.7**	**2634.8**	**2618.6**	**2574.2**	**3117.7**	**3007.6**	**2841.5**	**3500.6**	**3314.1**	**2988.9**
Carbon Dioxide Emissions by Primary Fuel (million metric tons)										
Petroleum	2499.2	2919.0	2896.7	2864.1	3487.0	3326.5	3191.6	3767.0	3530.0	3345.6
Natural Gas	1169.7	1395.8	1370.2	1344.4	1670.1	1614.0	1531.2	1711.6	1652.9	1602.0
Coal	2102.5	2352.9	2339.5	2304.6	2636.1	2557.9	2412.3	3017.9	2857.9	2502.2
Other	17.3	20.4	20.4	19.9	21.5	21.2	21.0	22.5	21.5	21.5
Total	**5788.7**	**6688.0**	**6626.8**	**6533.0**	**7814.8**	**7519.6**	**7156.2**	**8519.0**	**8062.3**	**7471.3**

Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LTRKITEN.D111504A, AEO2005.D102004A, and HTRKITEN.D111604A.

Table E5. Key Results for Advanced Nuclear Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2003	2010			2020			2025		
		Reference	Vendor Estimates	Advanced Nuclear Cost	Reference	Vendor Estimates	Advanced Nuclear Cost	Reference	Vendor Estimates	Advanced Nuclear Cost
Capacity										
Coal Steam	310.3	309.7	310.2	310.2	339.7	337.0	339.2	394.3	379.8	388.4
Other Fossil Steam	129.7	120.5	120.5	120.5	101.1	100.3	100.3	100.5	99.6	99.6
Combined Cycle	138.2	169.9	169.9	169.9	210.3	207.4	210.8	222.9	219.2	224.3
Combustion Turbine/Diesel	129.9	137.7	137.7	137.7	173.0	173.6	173.3	193.7	191.3	192.8
Nuclear Power	99.2	100.6	100.6	100.6	102.7	108.9	102.7	102.7	127.8	110.1
Pumped Storage	20.8	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	92.2	95.3	95.3	95.3	99.3	98.5	99.0	103.1	101.3	102.8
Distributed Generation (Natural Gas)	0.0	0.4	0.4	0.4	3.1	3.0	2.9	6.9	6.5	6.6
Combined Heat and Power[1]	27.1	32.1	32.1	32.1	39.2	39.3	39.3	44.8	44.8	44.8
Total	**947.4**	**987.0**	**987.5**	**987.5**	**1089.3**	**1088.7**	**1088.4**	**1189.7**	**1191.1**	**1190.4**
Cumulative Additions										
Coal Steam	0.0	1.8	1.8	1.8	32.4	29.1	31.4	86.9	71.9	80.6
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	31.8	31.8	31.8	72.5	69.4	72.8	85.1	81.2	86.3
Combustion Turbine/Diesel	0.0	9.7	9.7	9.7	51.2	51.2	51.3	73.8	70.2	72.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	6.2	0.0	0.0	25.1	7.4
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	2.9	2.9	2.9	6.9	6.1	6.7	10.7	8.9	10.4
Distributed Generation	0.0	0.4	0.4	0.4	3.1	3.0	2.9	6.9	6.5	6.6
Combined Heat and Power[1]	0.0	5.0	5.0	5.0	12.1	12.2	12.2	17.7	17.7	17.7
Total	**0.0**	**51.5**	**51.6**	**51.6**	**178.1**	**177.2**	**177.3**	**281.1**	**281.6**	**281.2**
Cumulative Retirements	**0.0**	**13.8**	**13.3**	**13.3**	**40.1**	**39.8**	**40.1**	**42.6**	**41.7**	**42.1**
Generation by Fuel (billion kilowatthours)										
Coal	1950	2203	2205	2205	2473	2450	2471	2869	2753	2824
Petroleum	113	117	117	117	131	129	131	135	130	132
Natural Gas	556	822	820	820	1234	1220	1240	1234	1183	1226
Nuclear Power	764	813	813	813	830	877	830	830	1017	886
Pumped Storage	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources	323	393	393	393	416	412	415	434	427	434
Distributed Generation	0	0	0	0	1	1	1	3	3	3
Combined Heat and Power[1]	153	187	187	187	238	238	238	273	273	273
Total	**3850**	**4526**	**4526**	**4526**	**5314**	**5318**	**5317**	**5770**	**5777**	**5769**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	95.8	96.3	96.2	96.2	106.9	104.9	106.7	109.2	105.0	106.5
Natural Gas	266.6	362.1	361.1	361.0	508.0	504.5	510.5	506.5	487.7	502.6
Coal	1906.0	2139.8	2141.8	2141.8	2371.5	2353.8	2371.0	2676.8	2582.2	2639.6
Other	17.3	20.4	20.4	20.4	21.2	21.2	21.2	21.5	21.5	21.6
Total	**2285.7**	**2618.6**	**2619.5**	**2619.4**	**3007.6**	**2984.4**	**3009.3**	**3314.1**	**3196.4**	**3270.2**
Prices to the Electric Power Sector[2] (2003 dollars per million Btu)										
Petroleum	5.28	4.55	4.55	4.55	5.10	5.10	5.10	5.42	5.41	5.42
Natural Gas	5.46	4.27	4.27	4.27	5.20	5.12	5.17	5.44	5.29	5.41
Coal	1.28	1.25	1.25	1.25	1.25	1.24	1.25	1.31	1.28	1.30

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.

Source: Energy Information Administration, AEO2005 National Energy Modeling System runs AEO2005.D102004A, ADVNUC5A.D110804A, and ADVNUC20.D102104A.

Table E6. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2003	2010			2020			2025		
		Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil
Capacity										
Pulverized Coal	309.8	309.3	309.2	309.2	336.8	336.6	319.1	390.2	377.7	327.7
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	0.8	3.1	12.4	0.8	16.5	40.2
Conventional Natural Gas Combined-Cycle	138.2	166.6	166.6	166.5	171.1	167.2	166.4	173.1	167.8	166.4
Advanced Natural Gas Combined-Cycle	0.0	2.7	3.3	3.6	22.4	43.1	88.0	26.3	55.1	131.3
Conventional Combustion Turbine	129.9	132.6	132.1	132.0	135.5	128.4	125.8	137.4	127.6	125.2
Advanced Combustion Turbine	0.0	5.6	5.6	5.8	50.8	44.6	21.8	71.1	66.1	37.6
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	99.2	100.6	100.6	100.6	102.7	102.7	102.7	102.7	102.7	102.7
Oil and Gas Steam	129.7	120.5	120.5	120.5	101.4	101.1	96.8	100.7	100.5	92.2
Renewable Sources/Pumped Storage	113.0	116.1	116.1	116.1	121.0	120.2	118.4	125.4	124.0	120.2
Distributed Generation	0.0	0.4	0.4	0.4	5.6	3.1	2.1	12.8	6.9	3.7
Combined Heat and Power[1]	27.1	32.1	32.1	32.1	39.5	39.2	38.6	45.6	44.8	43.3
Total	**947.4**	**987.0**	**987.0**	**987.1**	**1087.6**	**1089.3**	**1092.2**	**1186.1**	**1189.7**	**1190.4**
Cumulative Additions										
Pulverized Coal	0.0	1.9	1.8	1.8	30.0	29.8	12.3	83.3	70.9	20.9
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	0.3	2.6	11.9	0.3	16.0	39.7
Conventional Natural Gas Combined-Cycle	0.0	28.5	28.5	28.4	33.2	29.4	28.4	35.2	29.9	28.4
Advanced Natural Gas Combined-Cycle	0.0	2.7	3.3	3.6	22.4	43.1	88.0	26.3	55.1	131.3
Conventional Combustion Turbine	0.0	4.6	4.1	4.0	12.5	6.6	4.8	15.4	7.7	5.2
Advanced Combustion Turbine	0.0	5.6	5.6	5.8	50.8	44.6	21.8	71.1	66.1	37.6
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	2.9	2.9	2.8	7.7	6.9	5.1	12.2	10.7	7.0
Distributed Generation	0.0	0.4	0.4	0.4	5.6	3.1	2.1	12.8	6.9	3.7
Combined Heat and Power[1]	0.0	5.0	5.0	5.0	12.4	12.1	11.5	18.5	17.7	16.2
Total	**0.0**	**51.6**	**51.5**	**51.6**	**174.9**	**178.1**	**186.0**	**275.2**	**281.1**	**289.9**
Cumulative Retirements	**0.0**	**13.8**	**13.8**	**13.8**	**38.6**	**40.1**	**45.1**	**40.3**	**42.6**	**50.8**
Generation by Fuel (billion kilowatthours)										
Coal	1949.7	2204.1	2202.6	2202.6	2460.1	2473.2	2418.7	2843.2	2869.4	2688.1
Petroleum	112.6	117.5	117.3	117.0	143.5	131.1	126.9	142.0	135.3	157.2
Natural Gas	555.9	820.3	821.7	822.5	1214.2	1233.7	1333.1	1208.6	1233.9	1434.7
Nuclear Power	763.7	813.3	813.3	813.3	830.2	830.2	830.2	830.2	830.2	830.2
Renewable Sources/Pumped Storage	314.7	383.8	384.1	383.9	412.8	406.8	398.9	438.8	425.4	410.4
Distributed Generation	0.0	0.2	0.2	0.2	2.4	1.3	0.9	5.6	3.0	1.6
Combined Heat and Power[1]	153.3	186.6	186.6	186.6	239.9	238.1	233.6	278.6	272.8	262.4
Total	**3849.9**	**4525.7**	**4525.8**	**4526.0**	**5303.1**	**5314.4**	**5342.3**	**5747.1**	**5770.0**	**5784.6**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.49	22.83	22.81	22.81	25.20	25.28	24.66	28.48	28.54	26.56
Petroleum	1.13	1.26	1.26	1.26	1.48	1.40	1.35	1.50	1.43	1.56
Natural Gas	5.06	6.87	6.87	6.86	9.81	9.64	9.62	9.80	9.61	9.99
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Sources	3.62	4.29	4.30	4.30	4.91	4.75	4.65	5.42	5.14	4.90
Total	**38.27**	**43.75**	**43.74**	**43.72**	**50.07**	**49.74**	**48.96**	**53.87**	**53.39**	**51.68**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1906.0	2141.1	2139.8	2139.6	2364.3	2371.5	2314.1	2671.1	2676.8	2490.7
Petroleum	95.8	96.4	96.3	96.1	113.2	106.9	103.5	114.2	109.2	118.5
Natural Gas	266.6	362.0	362.1	361.4	517.1	508.0	507.0	516.4	506.5	526.2
Other	17.3	20.4	20.4	20.4	21.6	21.2	20.8	22.0	21.5	21.1
Total	**2285.7**	**2620.0**	**2618.6**	**2617.6**	**3016.2**	**3007.6**	**2945.4**	**3323.7**	**3314.1**	**3156.5**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LFOSS05.D102104A, AEO2005.D102004A, and HFOSS05.D102104A.

Table E7. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2003	2010			2020			2025		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	77.93	78.18	78.18	78.18	78.18	78.18	78.18	78.18	78.18	78.18
Geothermal[2]	2.18	2.23	2.21	2.21	3.43	3.45	5.63	4.21	4.62	7.30
Municipal Solid Waste[3]	3.34	3.57	3.57	3.57	3.63	3.66	3.70	3.64	3.67	3.71
Wood and Other Biomass[4]	1.77	1.83	1.83	1.78	2.40	2.75	2.62	3.77	4.50	5.18
Solar Thermal	0.39	0.45	0.45	0.45	0.49	0.49	0.49	0.51	0.51	0.51
Solar Photovoltaic	0.04	0.15	0.15	0.15	0.32	0.32	0.32	0.40	0.40	0.40
Wind	6.56	8.88	8.88	8.88	9.52	10.45	11.63	9.91	11.25	13.97
Total	**92.21**	**95.29**	**95.27**	**95.22**	**97.97**	**99.29**	**102.57**	**100.62**	**103.13**	**109.27**
Commercial and Industrial Sector										
Conventional Hydropower	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Wood and Other Biomass	4.08	5.10	5.14	5.51	6.04	6.18	7.52	6.56	6.75	8.69
Solar Photovoltaic	0.06	0.39	0.39	0.39	0.50	0.80	0.99	0.68	1.80	2.32
Total	**5.43**	**6.78**	**6.82**	**7.20**	**7.84**	**8.27**	**9.80**	**8.53**	**9.85**	**12.30**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	1950	2202	2203	2200	2474	2473	2468	2872	2869	2847
Petroleum	113	117	117	117	132	131	131	136	135	133
Natural Gas	556	822	822	820	1238	1234	1211	1245	1234	1213
Total Fossil	**2618**	**3141**	**3142**	**3137**	**3843**	**3838**	**3810**	**4252**	**4239**	**4193**
Conventional Hydropower	269.29	300.39	300.39	300.39	300.81	300.81	300.81	301.10	301.09	301.09
Geothermal	13.15	12.53	12.33	12.33	22.71	22.83	41.33	29.36	32.78	55.65
Municipal Solid Waste[3]	20.28	25.58	25.58	25.58	26.12	26.36	26.72	26.24	26.49	26.87
Wood and Other Biomass[4]	9.40	27.66	27.61	29.58	31.70	32.35	33.63	34.86	37.35	44.08
Dedicated Plants	5.73	10.30	10.32	10.08	14.04	16.21	14.86	22.35	27.29	31.66
Cofiring	3.66	17.37	17.29	19.50	17.66	16.13	18.77	12.51	10.06	12.42
Solar Thermal	0.53	0.80	0.80	0.80	0.92	0.92	0.92	0.99	0.99	0.99
Solar Photovoltaic	0.00	0.32	0.32	0.32	0.74	0.74	0.74	0.96	0.96	0.96
Wind	10.73	25.89	25.89	25.89	28.14	31.61	36.15	29.48	34.52	44.60
Total Renewable	**323.38**	**393.16**	**392.90**	**394.88**	**411.14**	**415.61**	**440.31**	**423.00**	**434.19**	**474.25**
Commercial and Industrial Sector[5]										
Total Fossil	102	130	130	130	174	173	173	202	202	202
Conventional Hydropower[6]	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	1.86	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
Wood and Other Biomass	27.59	33.52	33.76	35.96	39.06	39.86	47.65	42.07	43.21	54.50
Solar Photovoltaic	0.12	0.83	0.83	0.83	1.06	1.68	2.08	1.42	3.74	4.78
Total Renewables	**35.39**	**42.41**	**42.64**	**44.84**	**48.17**	**49.60**	**57.78**	**51.55**	**55.00**	**67.33**
Sources of Ethanol										
From Corn	0.24	0.32	0.32	0.32	0.34	0.34	0.34	0.34	0.34	0.34
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.04	0.04	0.04
Total	**0.24**	**0.32**	**0.32**	**0.32**	**0.35**	**0.36**	**0.35**	**0.38**	**0.38**	**0.38**
Carbon Dioxide Emissions by the Power Sector (million metric tons)[1]										
Coal	1906.0	2139.6	2139.8	2136.9	2371.7	2371.5	2367.3	2678.0	2676.8	2659.0
Petroleum	95.8	96.2	96.3	96.4	107.3	106.9	106.8	109.5	109.2	107.6
Natural Gas	266.6	361.9	362.1	361.3	509.6	508.0	500.5	509.8	506.5	498.5
Other	17.3	20.4	20.4	20.4	21.0	21.2	22.0	21.3	21.5	22.4
Total	**2285.7**	**2618.1**	**2618.6**	**2615.0**	**3009.6**	**3007.6**	**2996.7**	**3318.6**	**3314.1**	**3287.6**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2005 National Energy Modeling System runs LOREN05.D111504A, AEO2005.D102004A, and HIREN05.D111604A.

Table E8. Total Energy Supply and Disposition, Oil and Gas Technological Progress Cases
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Production										
Crude Oil and Lease Condensate	12.03	12.56	12.75	12.99	10.56	11.03	11.46	9.43	10.01	10.83
Natural Gas Plant Liquids	2.34	2.59	2.66	2.75	2.65	2.80	2.98	2.58	2.81	3.08
Dry Natural Gas	19.58	20.15	20.97	21.91	20.81	22.48	24.39	20.12	22.42	25.37
Coal	22.66	25.13	25.10	25.03	27.88	27.04	26.08	31.21	29.90	27.96
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.86	7.61	7.57	7.52	8.24	8.10	8.08
Other[2]	0.93	0.96	0.97	0.98	0.75	0.77	0.77	0.82	0.82	0.83
Total	**71.42**	**76.73**	**77.79**	**79.01**	**78.92**	**80.35**	**81.87**	**81.07**	**82.73**	**84.82**
Imports										
Crude Oil[3]	21.08	24.92	24.69	24.37	32.88	32.29	31.91	35.84	35.16	34.34
Petroleum Products[4]	5.16	6.09	6.06	6.01	7.13	6.83	6.49	8.55	8.27	7.87
Natural Gas	4.02	6.20	5.71	5.26	9.07	8.95	8.62	9.80	9.70	9.34
Other Imports[5]	0.69	0.92	0.92	0.92	1.14	1.15	1.15	1.22	1.23	1.24
Total	**30.95**	**38.13**	**37.38**	**36.56**	**50.22**	**49.22**	**48.17**	**55.42**	**54.36**	**52.80**
Exports										
Petroleum[6]	2.13	2.14	2.14	2.14	2.28	2.26	2.25	2.34	2.32	2.31
Natural Gas	0.70	0.64	0.65	0.67	0.80	0.86	0.94	0.73	0.83	0.97
Coal	1.12	1.06	1.06	1.06	0.89	0.89	0.88	0.65	0.65	0.67
Total	**3.95**	**3.84**	**3.86**	**3.87**	**3.97**	**4.01**	**4.07**	**3.71**	**3.80**	**3.95**
Consumption										
Petroleum Products[7]	39.09	44.81	44.84	44.85	51.49	51.30	51.24	54.51	54.42	54.39
Natural Gas	22.54	25.78	26.11	26.57	29.26	30.73	32.23	29.39	31.47	33.92
Coal	22.71	24.98	24.95	24.88	28.11	27.27	26.34	31.79	30.48	28.54
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.89	6.85	6.85	6.86	7.61	7.57	7.52	8.24	8.10	8.08
Other[8]	0.02	0.04	0.03	0.03	0.05	0.05	0.05	0.04	0.04	0.04
Total	**98.22**	**110.96**	**111.27**	**111.68**	**125.19**	**125.60**	**126.05**	**132.63**	**133.18**	**133.63**
Net Imports - Petroleum	**24.10**	**28.86**	**28.61**	**28.24**	**37.73**	**36.87**	**36.15**	**42.06**	**41.11**	**39.90**
Prices (2003 dollars per unit)										
World Oil Price (dollars per barrel)[9]	27.73	25.00	25.00	25.00	28.50	28.50	28.50	30.31	30.31	30.31
Natural Gas Wellhead Price (dollars per thousand cubic feet)[10]	4.98	3.81	3.64	3.35	4.86	4.53	4.11	5.18	4.79	4.35
Coal Minemouth Price (dollars per ton)	17.93	17.33	17.30	17.24	18.06	17.25	16.91	19.11	18.26	17.41
Average Electricity Price (cents per kilowatthour)	7.4	6.7	6.6	6.5	7.3	7.2	7.0	7.4	7.3	7.1
Carbon Dioxide Emissions (million metric tons)	**5788.7**	**6611.2**	**6626.8**	**6642.7**	**7535.0**	**7519.6**	**7505.1**	**8082.7**	**8062.3**	**8003.9**

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). 2003 carbon dioxide emission values: EIA, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs OGLTEC05.D102704A, AEO2005.D102004A, and OGHTEC05.D102704A.

Table E9. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Lower 48 Average Wellhead Price (2003 dollars per thousand cubic feet)	**4.98**	**3.81**	**3.64**	**3.35**	**4.86**	**4.53**	**4.11**	**5.18**	**4.79**	**4.35**
Dry Gas Production[1]	**19.07**	**19.62**	**20.42**	**21.34**	**20.27**	**21.89**	**23.75**	**19.60**	**21.83**	**24.71**
Lower 48 Onshore	13.89	14.40	14.98	15.64	13.72	15.30	16.81	13.07	14.71	17.21
Associated-Dissolved	1.54	1.31	1.32	1.32	1.13	1.15	1.17	1.06	1.08	1.11
Non-Associated	12.36	13.09	13.66	14.32	12.59	14.16	15.64	12.02	13.63	16.10
Conventional	5.77	5.54	5.60	5.66	5.27	5.40	5.37	4.90	5.02	5.08
Unconventional	6.59	7.55	8.06	8.65	7.32	8.75	10.28	7.12	8.61	11.03
Lower 48 Offshore	4.73	4.97	5.19	5.45	4.31	4.70	5.06	4.29	4.89	5.25
Associated-Dissolved	0.99	1.77	1.81	1.86	1.31	1.39	1.48	1.20	1.34	1.43
Non-Associated	3.74	3.20	3.38	3.59	3.00	3.31	3.58	3.09	3.56	3.82
Alaska	0.44	0.25	0.25	0.25	2.24	1.89	1.89	2.23	2.23	2.24
Supplemental Natural Gas[2]	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Net Imports	**3.24**	**5.43**	**4.94**	**4.47**	**8.07**	**7.89**	**7.49**	**8.86**	**8.66**	**8.17**
Canada	3.13	2.41	2.57	2.60	2.44	2.69	2.80	2.10	2.55	2.90
Mexico	-0.33	-0.12	-0.14	-0.16	-0.28	-0.35	-0.42	-0.03	-0.25	-0.45
Liquefied Natural Gas	0.44	3.14	2.50	2.03	5.92	5.54	5.11	6.78	6.37	5.72
Total Supply	**22.37**	**25.12**	**25.44**	**25.88**	**28.41**	**29.85**	**31.32**	**28.53**	**30.56**	**32.96**
Consumption by Sector										
Residential	5.10	5.47	5.52	5.59	5.81	5.88	5.95	5.91	5.99	6.09
Commercial	3.13	3.36	3.39	3.43	3.74	3.80	3.86	3.98	4.05	4.15
Industrial[3]	6.99	7.81	7.87	7.98	8.53	8.64	8.77	8.80	9.00	9.22
Electric Power[4]	4.96	6.62	6.74	6.91	8.35	9.45	10.52	7.90	9.43	11.17
Transportation[5]	0.02	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.64	0.67	0.68	0.70	0.77	0.80	0.85	0.76	0.82	0.90
Lease and Plant Fuel[6]	1.12	1.13	1.17	1.21	1.22	1.29	1.37	1.17	1.27	1.41
Total	**21.95**	**25.12**	**25.44**	**25.88**	**28.51**	**29.95**	**31.42**	**28.64**	**30.67**	**33.06**
Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.42**	**-0.00**	**-0.00**	**-0.00**	**-0.10**	**-0.10**	**-0.10**	**-0.11**	**-0.11**	**-0.11**
Lower 48 End of Year Reserves	**180.77**	**196.29**	**204.21**	**214.24**	**167.58**	**186.10**	**209.87**	**159.19**	**178.29**	**205.34**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs OGLTEC05.D102704A, AEO2005.D102004A, and OGHTEC05.D102704A.

Table E10. Petroleum Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010			2020			2025		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
World Oil Price (2003 dollars per barrel)	27.73	25.00	25.00	25.00	28.50	28.50	28.50	30.31	30.31	30.31
Crude Oil Supply										
Domestic Crude Oil Production[1]	5.68	5.93	6.02	6.13	4.99	5.21	5.42	4.45	4.73	5.11
Lower 48 Onshore	2.99	2.61	2.63	2.66	2.18	2.24	2.32	2.00	2.09	2.19
Lower 48 Offshore	1.72	2.52	2.58	2.67	1.98	2.11	2.23	1.86	2.03	2.20
Alaska	0.97	0.80	0.81	0.81	0.83	0.86	0.86	0.60	0.61	0.72
Net Crude Oil Imports	9.65	11.41	11.31	11.16	15.07	14.80	14.62	16.43	16.11	15.73
Other Crude Oil Supply	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	15.31	17.35	17.33	17.30	20.05	20.01	20.04	20.88	20.84	20.85
Other Petroleum Supply										
Natural Gas Plant Liquids	1.72	1.90	1.96	2.02	1.93	2.04	2.17	1.88	2.04	2.24
Net Petroleum Product Imports[2]	1.58	2.08	2.06	2.03	2.46	2.31	2.13	3.14	3.00	2.79
Refinery Processing Gain[3]	1.00	1.11	1.11	1.10	1.51	1.50	1.49	1.58	1.56	1.54
Other Supply[4]	0.69	0.52	0.53	0.54	0.45	0.46	0.47	0.49	0.50	0.50
Total Primary Supply[5]	20.30	22.97	22.98	22.99	26.41	26.32	26.29	27.97	27.93	27.92
Refined Petroleum Products Supplied										
Residential and Commercial	1.28	1.33	1.33	1.33	1.41	1.41	1.40	1.43	1.42	1.41
Industrial[6]	4.87	5.32	5.33	5.33	5.80	5.81	5.81	6.04	6.05	6.08
Transportation	13.35	15.74	15.76	15.78	18.46	18.48	18.50	19.79	19.82	19.85
Electric Power[7]	0.50	0.57	0.56	0.54	0.74	0.62	0.58	0.71	0.64	0.58
Total	20.00	22.97	22.98	22.99	26.41	26.32	26.29	27.97	27.93	27.92
Discrepancy[8]	0.29	0.00	-0.00	-0.00	-0.00	0.00	-0.00	-0.00	-0.00	-0.00
Lower 48 End of Year Reserves (billion barrels)[1]	18.94	20.93	21.23	21.64	17.08	17.79	18.22	15.79	16.47	16.65

[1]Includes lease condensate.
[2]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[3]Represents volumetric gain in refinery distillation and cracking processes.
[4]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[5]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[6]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[7]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 product supplied data based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). Other 2003 data: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs OGLTEC05.D102704A, AEO2005.D102004A, and OGHTEC05.D102704A.

Table E11. Natural Gas Prices, Supply, and Disposition, Restricted Supply Case
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	2010		2015		2020		2025	
		Reference	Restricted Natural Gas Supply	Reference	Restricted Natural Gas Supply	Reference	Restricted Natural Gas Supply	Reference	Restricted Natural Gas Supply
Natural Gas Prices (2003 dollars per thousand cubic feet)									
Lower 48 Average Wellhead Price	4.98	3.64	4.23	4.16	5.13	4.53	5.88	4.79	6.29
Average Delivered Natural Gas Price	7.04	5.67	6.28	6.08	7.11	6.47	7.96	6.77	8.52
Natural Gas Supply									
Dry Natural Gas Production[1]	19.07	20.42	20.26	20.77	20.44	21.89	19.81	21.83	19.07
Lower 48 Onshore	13.89	14.98	14.91	15.38	15.18	15.30	15.03	14.71	14.19
Associated-Dissolved	1.54	1.32	1.31	1.22	1.21	1.15	1.13	1.08	1.05
Non-Associated	12.36	13.66	13.60	14.16	13.97	14.16	13.90	13.63	13.14
Conventional	5.77	5.60	5.76	5.62	5.77	5.40	5.49	5.02	5.04
Unconventional	6.59	8.06	7.84	8.54	8.20	8.75	8.41	8.61	8.10
Lower 48 Offshore	4.73	5.19	5.10	5.12	4.99	4.70	4.52	4.89	4.62
Associated-Dissolved	0.99	1.81	1.77	1.48	1.42	1.39	1.34	1.34	1.28
Non-Associated	3.74	3.38	3.33	3.64	3.58	3.31	3.18	3.56	3.34
Alaska	0.44	0.25	0.25	0.27	0.27	1.89	0.27	2.23	0.26
Supplemental Natural Gas[2]	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Net Imports	3.24	4.94	4.40	7.02	5.33	7.89	5.59	8.66	5.21
Canada	3.13	2.57	2.62	2.98	3.18	2.69	3.06	2.55	2.31
Mexico	-0.33	-0.14	-0.11	-0.29	-0.20	-0.35	0.04	-0.25	0.40
Liquefied Natural Gas	0.44	2.50	1.88	4.33	2.35	5.54	2.49	6.37	2.49
Total Supply	**22.37**	**25.44**	**24.74**	**27.86**	**25.84**	**29.85**	**25.48**	**30.56**	**24.35**
Natural Gas Consumption by Sector									
Residential	5.10	5.52	5.42	5.74	5.57	5.88	5.55	5.99	5.44
Commercial	3.13	3.39	3.32	3.58	3.46	3.80	3.61	4.05	3.81
Industrial[3]	6.99	7.87	7.72	8.26	7.99	8.64	8.06	9.00	8.26
Electric Power[4]	4.96	6.74	6.38	8.39	7.00	9.45	6.46	9.43	5.14
Transportation[5]	0.02	0.06	0.06	0.08	0.08	0.10	0.09	0.11	0.10
End Use Subtotal	**20.19**	**23.58**	**22.91**	**26.05**	**24.09**	**27.86**	**23.78**	**28.58**	**22.76**
Pipeline Fuel	0.64	0.68	0.66	0.71	0.66	0.80	0.64	0.82	0.62
Lease and Plant Fuel[6]	1.12	1.17	1.16	1.20	1.18	1.29	1.15	1.27	1.09
Total Consumption	**21.95**	**25.44**	**24.74**	**27.96**	**25.94**	**29.95**	**25.57**	**30.67**	**24.46**
Discrepancy[7]	**0.42**	**-0.00**	**0.00**	**-0.09**	**-0.10**	**-0.10**	**-0.10**	**-0.11**	**-0.11**
Total U.S. Electricity Consumption (billion kilowatthours)	3,657	4,274	4,256	4,644	4,600	5,040	4,972	5,467	5,420
Average Delivered Electricity Price (2003 cents per kilowatthour)	7.4	6.6	6.8	6.9	7.3	7.2	7.6	7.3	7.5
Real Gross Domestic Product (billion 2000 dollars)	10,381	13,084	13,068	15,216	15,191	17,634	17,596	20,292	20,264
Delivered Natural Gas Expenditures (billion 2003 dollars)	142.2	133.7	143.8	158.4	171.3	180.2	189.3	193.4	193.9
Natural Gas Expenditures per Dollar Gross Domestic Product (percent)	1.37%	1.02%	1.10%	1.04%	1.13%	1.02%	1.08%	0.95%	0.96%
Natural Gas Expenditures per Capita (dollars per person)	487.96	430.97	463.57	489.70	529.52	534.73	561.60	551.44	552.89

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs AEO2005.D102004A, and RESSUP.D102704A.

Appendix F

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2005* (*AEO2005*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years into the future. In order to represent the regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council (NERC) regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply availability.

The integrating module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data file. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules, permitting the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of October 31, 2004, such as the Clean Air Act Amendments (CAAA), and the costs of compliance with regulations, such as the new boiler limits established by the U.S. Environmental Protection Agency (EPA) under the CAAA on February 26, 2004; and the 13 SEER standard for new central air conditioners and heat pumps that was reestablished by the U.S. Court of Appeals, Second Circuit, after originally being set in January 2001.

In general, the historical data used for the *AEO2005* projections were based on EIA's *Annual Energy Review 2003*, published in September 2004 [*1*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2003. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2003*, published in December 2004 [*2*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Some definitional adjustments were made to EIA data for the forecasts. For example, the transportation demand sector in *AEO2005* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2005* projections for 2004 and 2005 incorporate short-term projections from EIA's October 2004 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [3].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), industrial output, interest rates, disposable income, prices, and employment. This module uses the following Global Insight models: Macroeconomic Model of the U.S. Economy, national Industry Model, and national Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to forecast regional economic drivers and a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census divisions. For *AEO2005*, bulk chemicals are disaggregated into organic and inorganic chemicals, resins, and agricultural chemicals. In addition, the accounting framework for industrial output has changed from the Standard Industrial Classification (SIC) system to the North American Industry Classification System (NAICS), which has reclassified the components of gross industrial output and moved some manufacturing activities into services.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS, in response to changes in U.S. import requirements. Fourteen international petroleum product supply curves, including curves for oxygenates, are also calculated and provided to the PMM. A world oil supply/demand balance is created, including estimates for 16 oil consumption regions and 18 oil production regions. The oil production estimates include both conventional and nonconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module forecasts consumption of commercial sector energy by building types and nonbuilding uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction. Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies and effects of both building shell and appliance standards. The commercial module incorporates combined heat and power (CHP) technology. The modules also include forecasts of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on State-level population projections. The Residential Demand Module projects that the average square footage of both new construction and existing structures is increasing, based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the macroeconomic module, the value of shipments is now based on NAICS rather than SIC. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/ assembly use of energy. Bulk chemicals have been further disaggregated to organic, inorganic, resins, and other petroleum products. A representation of cogeneration and a recycling component are also included. The use of

energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles. The air transportation module explicitly represents the industry practice of parking aircraft to reduce operating costs and the movement of aircraft from the passenger to cargo markets as aircraft age [*4*]. For air freight shipments, the model employs narrow-body and wide-body aircraft only. The model also uses an infrastructure constraint that limits air travel growth to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module (EMM) represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs; macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are modeled in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the Electricity Market Module.

All specifically identified CAAA compliance options that have been promulgated by the EPA are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated are not incorporated (e.g., fine particulate proposal). Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, regulations are represented in *AEO2005*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing natural resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in the Energy Policy Act of 1992 [*5*]. They provide a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power. The credits have no expiration date.

Production tax credits for wind and some types of biomass-fueled plants are also represented. They provide a tax credit of 1.8 cents per kilowatthour for electricity produced in the first 10 years of plant operation. New plants that come on line before January 1, 2006, are eligible to receive the credit. For a description of significant changes made for *AEO2005* in the representation of biomass resource supply, conventional hydroelectricity, wind resources, cost and performance characteristics for wind technologies, and accounting of new renewable energy capacity from State renewable portfolio standards, mandates, and goals, see the "Renewable Fuels Module" chapter of *Assumptions for the Annual Energy Outlook 2005*.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and gas production functions are computed at

a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and liquefied natural gas (LNG) imports and exports.

Crude oil production quantities are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities. International LNG supply sources and options for regional expansions of domestic regasification capacity are represented, based on the projected regional costs associated with gas supply, liquefaction, transportation, regasification, and natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module (NGTDM) represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas in an aggregate, domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and non-core markets are represented at the burner tip. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities in the five PADDs. The module uses the same crude oil types as the International Energy Module. It explicitly models the requirements of CAAA and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2005* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New Hampshire, New York, Ohio, South Dakota, Washington, and Wisconsin.

The Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas is assumed to remain intact. The nationwide phase-in of gasoline with an annual average sulfur content of 30 ppm between 2005 and 2007, and the diesel regulations that limit the sulfur content to 15 ppm in highway diesel starting mid-2006 and in all nonroad and locomotive/marine diesel fuel by mid-2012, are represented in *AEO2005*. Growth in demand and the costs of the regulations lead to capacity expansion for refinery-processing units, assuming a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment at about 10 percent [6]. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs and State and Federal taxes [7]. Refinery capacity expansion at existing sites may occur in all five refining regions modeled.

Fuel ethanol and biodiesel are included in PMM because they are commonly blended into petroleum products. The PMM allows ethanol blending into gasoline at 10 percent by volume or less and also allows limited quantities of E85, a blend of up to 85 percent ethanol by volume. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and it is expected to be produced from cellulosic material in other regions in the future. Biodiesel is produced from soybean oil or yellow grease, which is primarily recycled cooking oil. Soybean oil biodiesel is assumed to be blended into highway diesel, and yellow grease biodiesel is assumed to be blended into non-highway diesel.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM using 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to

capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined in the CMM through the use of a linear programming algorithm that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for minemouth prices, transportation costs, existing coal supply contracts, and sulfur allowance costs. Over the forecast horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the user cost of rail transportation equipment.

The CMM produces projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The CMM's linear programming algorithm determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a pre-specified set of regional world coal import demands, subject to constraints on export capacities by country and coal type and trade flows.

U.S. coal production and distribution are computed for 14 supply and 14 demand regions. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. Projections of annual U.S. coal imports, specified by demand region and sector, are developed exogenously based primarily on the capability and plans of existing coal-fired power plants to import coal and announced plans to expand coal import infrastructure.

Annual Energy Outlook 2005 Cases

Table F1 provides a summary of the cases used to derive the *AEO2005* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

The following section describes cases listed in Table F1. The reference case assumptions for each sector are described at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement/.

Macroeconomic Growth Cases

In addition to the *AEO2005* reference case, the *low economic growth* and *high economic growth cases* were developed to reflect the uncertainty in forecasts of economic growth. The alternative cases are intended to show the projected effects of alternative growth assumptions on energy markets. The cases are described as follows:

- The *low economic growth case* assumes lower growth rates for population (0.6 percent per year), nonfarm employment (0.8 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the *low economic growth case*, economic output is projected to increase by 2.5 percent per year from 2003 through 2025, and growth in GDP per capita is projected to average only 1.9 percent per year.
- The *high economic growth case* assumes higher projected growth rates for population (1.0 percent per year), nonfarm employment (1.6 percent per year), and productivity (2.7 percent per year). With higher productivity gains and employment growth, inflation and interest rates are projected to be lower than in the reference case, and consequently economic output is projected to grow at a higher rate (3.6 percent per year) than in the reference case (3.1 percent). GDP per capita is expected to grow by 2.5 percent per year, compared with 2.2 percent in the reference case.

World Oil Market Cases

The world oil price in *AEO2005* is the annual average U.S. refiner's acquisition cost of imported crude oil (IRAC). Five distinct world oil price scenarios are represented in *AEO2005*, with prices reaching approximately $21, $30, $35, $39, and $48 per barrel in 2025, respectively, in the low world oil price, reference, October oil futures, high A world oil price, and high B world oil price cases in 2003 dollars. Because these oil price cases are not directly integrated with a world economic model, the impacts of world oil prices on international economies is not directly accounted for in this analysis.

- The *reference case* represents EIA's current judgment regarding the expected behavior of the Organization of Petroleum Exporting Countries (OPEC) in the mid-term, where production is adjusted to keep world oil prices in the $25 to $31

Table F1. Summary of the *AEO2005* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix F
Reference	Baseline economic growth (3.1 percent per annum), world oil price falling to about $25 per barrel by 2010 and rising to $30.31 per barrel, and technology assumptions.	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.5 percent from 2003 through 2025, compared with the reference case growth of 3.1 percent. Reference case assumptions otherwise.	Fully integrated	p. 73	p. 215
High Economic Growth	Gross domestic product grows at an average annual rate of 3.6 percent from 2003 through 2025, compared with the reference case growth of 3.1 percent. Reference case assumptions otherwise.	Fully integrated	p. 73	p. 215
Low World Oil Price	Reference case assumptions except that the world oil prices are $20.99 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 74	p. 218
October Oil Futures	World oil prices continue to rise in near term and are $35.00 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 44	p. 218
High A World Oil Price	Reference case assumptions except that the world oil prices are $39.24 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 74	p. 218
High B World Oil Price	World oil prices remain high and are $48.00 per barrel in 2025, compared with $30.31 per barrel in the reference case.	Fully integrated	p. 74	p. 218
Residential: 2005 Technology	Future equipment purchases based on equipment available in 2005. Existing building shell efficiencies fixed at 2005 levels.	With commercial	p. 84	p. 218
Residential: High Technology	Relative to the reference case, earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 21 percent from 2002 values by 2025.	With commercial	p. 84	p. 218
Residential: Best Available Technology	Relative to the reference case, future equipment purchases and new building shells based on most efficient technologies available. Heating shell efficiency increases by 25 percent from 2002 values by 2025.	With commercial	p. 84	p. 218
Commercial: 2005 Technology	Relative to the reference case, future equipment purchases are based on equipment available in 2005. Building shell efficiencies are fixed at 2005 levels.	With residential	p. 85	p. 219
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiencies for new and existing buildings increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025.	With residential	p. 85	p. 219
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Heating shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025.	With residential	p. 85	p. 219
Residential and Commercial: SEER 12	Replaces the recently enacted SEER 13 standard with the previously set level of SEER 12.	Fully integrated	p. 13	p. 218
Residential and Commercial: Warmer temperatures	Summer and winter temperatures trend to the average of the 5 warmest of the past 30 years by 2025.	Fully integrated	p. 55	p. 219

Table F1. Summary of the *AEO2005* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix F
Residential and Commercial: Colder temperatures	Summer and winter temperatures trend to the average of the 5 coldest of the past 30 years by 2025.	Fully integrated	p. 55	p. 219
Industrial: 2005 Technology	Efficiency of plant and equipment fixed at 2005 levels.	Standalone	p. 85	p. 219
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 85	p. 219
Transportation: 2005 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2005 levels.	Standalone	p. 86	p. 220
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 86	p. 220
Transportation: A.B.1493 California Only	Accounts for adoption of vehicle carbon dioxide emissions standards in California.	Fully integrated	p. 27	p. 220
Transportation: A.B.1493 Extended	Accounts for adoption of vehicle carbon dioxide emissions standards in California, New York, Maine, Massachusetts, and Vermont.	Fully integrated	p. 27	p. 220
Integrated 2005 Technology	Baseline macroeconomic drivers, combining the residential, commercial, industrial, and transportation 2005 technology assumptions with electricity low fossil technology and low renewable technology assumptions.	Fully integrated	p. 110	—
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case.	Fully integrated	p. 110	—
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have 20 percent lower capital and operating costs in 2025 than in the reference case.	Fully integrated	p. 93	p. 220
Electricity: Nuclear Vendor Estimate	New nuclear capacity is assumed to have lower capital costs based on vendor goals.	Fully integrated	p. 93	p. 221
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2025 from reference case values.	Fully integrated	p. 93	p. 221
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2005.	Fully integrated	p. 93	p. 221
Electricity: Proposed Clean Air Interstate Rule (pCAIR)	Limits on NO_x and SO_2 emissions.	Fully integrated	p.31	p. 221
Renewables: Low Renewables	New renewable generating technologies are assumed not to improve over time after 2005.	Fully Integrated	p. 94	p. 221
Renewables: High Renewables	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2025 from reference case values.	Fully Integrated	p. 94	p. 221
Renewables: PTC Extension	The production tax credit (PTC) for wind expires in 2005. *AEO2005* does not assume its extension consistent with the approach generally taken toward public policy in the forecast. This scenario assumes the extension of the PTC through 2015.	Fully integrated	p. 58	p. 222
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate technology parameters adjusted for 50 percent more rapid improvement than in the reference case.	Fully integrated	p. 97	p. 222

Table F1. Summary of the *AEO2005* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix F
Oil and Gas: Slow Technology	Cost, finding rate, and success rate technology parameters adjusted for 50 percent slower improvement than in the reference case.	Fully integrated	p. 97	p. 222
Oil and Gas: Restricted Natural Gas Supply	The slow oil and gas technology case with no Alaskan pipeline and no new U.S. LNG regasification terminals except those already under construction. Proposed expansions of existing U.S. LNG terminals are permitted to go into operation as currently scheduled.	Fully integrated	p. 66	p. 222
Oil and Gas: No Nonroad Diesel Rule	No new nonroad diesel rules.	Fully integrated	p. 14	p. 222

per barrel range and in keeping with their noted goal of keeping potential competitors from taking their market share. Since OPEC, particularly the Persian Gulf nations, is expected to be the dominant supplier of oil in the international market over the midterm, the organization's production choices will significantly affect world oil prices.

- The *low world oil price case* could result from a future market where all oil production becomes more competitive and plentiful.
- The world crude oil price in the *October oil futures case* was developed by extrapolating the U.S. refiner's acquisition cost of imported crude oil based loosely on the rate of growth of futures prices for West Texas Intermediate crude oil on the New York Mercantile Exchange. The prices in the *October oil futures case* continue to rise through 2005, reaching $44 per barrel, before gradually declining to $31 per barrel in 2010, $6 higher then the reference case projection. After 2010, prices rise to $35 per barrel in 2025, about $5 per barrel higher than in the reference case. Prices are above those in the reference case over the entire projection, but below those in the *high A world oil price case* and the *high B world oil price case.*
- The *high A world oil price case* could result from a more cohesive and market-assertive OPEC with lower production goals and other nonfinancial (geopolitical) considerations, including possibly a change in the target price band.
- The *high B world oil price case* could result from a number of possible events. For example, a very high world oil price could result from robust growth in worldwide oil demand, especially in the developing economies, coupled with the inability or unwillingness of OPEC producers to sufficiently expand their oil production capacity.

Buildings Sector Cases

In addition to the *AEO2005* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes to equipment and building shell efficiencies, and an integrated cooling efficiency standard case was developed to analyze the effect of the recently implemented 13 SEER standard for central air conditioners and heat pumps.

For the residential sector, the four technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Existing building shell efficiencies are assumed to be fixed at 2005 levels.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [8]. Heating shell efficiency in 2025 is projected to be 21 percent higher than the 2002 level.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Heating shell efficiency is projected to increase by 25 percent over 2002 levels by 2025.
- A *cooling efficiency standard case* for residential and commercial technologies is an integrated case designed to analyze the effects of the recently

enacted central air conditioner and heat pump standard on buildings-related energy use (residential and commercial). This case replaces the 13 SEER standard, which is used in the *AEO2005* reference case, with the previously enacted 12 SEER standard, effective in 2006.

For the commercial sector, the four technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Building shell efficiencies are assumed to be fixed at 2005 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*9*]. Heating shell efficiencies for new and existing buildings are assumed to increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025—a 25-percent improvement relative to the reference case.
- The *best available technology* case assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the *high technology case*, regardless of cost. Heating shell efficiencies for new and existing buildings are assumed to increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025—a 50-percent improvement relative to the reference case.
- A *cooling efficiency standard case* is as described for the residential sector above.

Two additional integrated cases were developed, in combination with assumptions for electricity generation from renewable fuels, to analyze the sensitivity of the projections to changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2025 that are approximately 10 percent lower than reference case costs for distributed photovoltaic technologies.
- The *low renewables case* assumes that costs and performance levels for residential and commercial photovoltaic systems remain constant at 2005 levels through 2025.

To illustrate the potential impacts of warmer and colder weather on buildings energy consumption relative to the reference case, two additional integrated cases were developed. For the residential and commercial demand modules:

- The *warmer temperature case* assumes that State-level heating and cooling degree-days trend to the average of the 5 warmest years of the past 30 years by 2025.
- The *colder temperature case* assumes that State-level heating and cooling degree-days trend to the average of the 5 coldest years of the past 30 years by 2025.

Industrial Sector Cases

In addition to the *AEO2005* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid technology change and adoption and more rapid technology change and adoption. The Industrial Demand Module was also used as part of and integrated *high renewables case.* For the industrial sector:

- The *2005 technology case* holds the energy efficiency of plant and equipment constant at the 2005 level over the forecast. In this case, delivered energy intensity falls by 1.0 percent annually. Because the level and composition of industrial output are the same in the reference, 2005 technology, and high technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. The *2005 technology case* was run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*10*]. The *high technology case* also assumes a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes, at 1.0 percent per year as compared with 0.1 percent per year in the reference case. The same assumption is also incorporated in the *integrated high renewable case*, which focuses on electricity generation. While the choice of 1 percent recovery is an assumption of the *high*

technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, delivered energy intensity falls by 1.6 percent annually in the *high technology case*. In the reference case, delivered energy intensity falls by 1.6 percent annually between 2003 and 2025.

Transportation Sector Cases

In addition to the *AEO2005* reference case, two standalone cases using the Transportation Demand Module of NEMS were developed to examine the effects of less rapid technology change and adoption and more rapid technology change and adoption. For the transportation sector:

- The *2005 technology case* assumes that new fuel efficiency levels remain constant at 2005 levels through the forecast horizon unless emission and/or efficiency regulations require the implementation of technology that affects vehicle efficiency. For example, the new light truck corporate average fuel economy (CAFE) standards require an increase in fuel economy through 2007, and increases in heavy truck emission standards are required through 2010. As a result, the technology available for light truck efficiency improvement is frozen at 2007 levels, and the technology available to heavy trucks is frozen at 2010 levels.
- For the *high technology case*, light-duty conventional and alternative-fuel vehicle characteristics reflect more optimistic assumptions for incremental fuel economy improvements and costs [*11*]. In the air travel sector, the *high technology case* reflects lower costs for improved thermodynamics, advanced aerodynamics, and weight reduction materials, which provides a 25-percent improvement in new aircraft efficiency compared to the reference case in 2025. In the freight truck sector, the *high technology case* assumes more optimistic incremental fuel efficiency improvements for engine and emission control technologies [*12*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

Both cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices incorporated.

In addition to the technology cases, two cases were developed to measure the impact of recently enacted carbon dioxide emission standards for light-duty vehicles in California (Assembly Bill 1493). These cases measure the energy and fuel price impacts that occur regionally, and vehicle sales impacts that occur in those States adopting A.B.1493.

- The *A.B.1493 California only case* assumes that only California adopts the new standards. The *A.B.1493 extended case* assumes that, in addition, New York, Maine, Massachusetts, and Vermont also adopt the light-duty vehicle carbon emissions standards. These cases assume that fuel economy impacts are limited to those States adopting the regulation, and that the fuel economy and sales mix of vehicles sold in all other States remain at the levels projected in the reference case. EIA estimates that meeting the requirements of A.B. 1493 will require new car fuel economy to increase from 27.5 miles per gallon in 2009 to 39.9 miles per gallon in 2016 and new light truck fuel economy to increase from 22.2 miles per gallon in 2009 to 26.4 miles per gallon in 2016.

Electricity Sector Cases

In addition to the reference case, four integrated cases with alternative electric power assumptions were developed to analyze the uncertainties regarding future costs and performance of new generating technologies. Two of the cases examine alternative nuclear assumptions, and two examine alternative fossil technology assumptions. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding newer, untested designs. The electricity cases analyze what could happen if costs of advanced designs are either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cases

- The cost assumptions for the *advanced nuclear cost case* reflect a 20-percent reduction in the capital and operating costs for advanced nuclear technology in 2025, relative to the reference case. Because the reference case assumes that some

learning occurs regardless of new orders and construction, the reference case already projects a 10-percent reduction in capital costs between 2005 and 2025. The *advanced nuclear cost case* assumes a 28-percent reduction between 2005 and 2025.

- The *nuclear vendor estimate case* assumptions are consistent with estimates from British Nuclear Fuel Limited (BNFL) for the manufacture of their Advanced Pressurized Water Reactor (AP1000). In this case, the overnight capital cost of a new advanced nuclear unit is assumed to be 18 percent lower initially than assumed in the reference case and 38 percent lower in 2025. For both advanced nuclear cases, cost and performance characteristics for all other technologies are as assumed in the reference case.

Fossil Technology Cases

- In the *high fossil technology case*, capital costs, heat rates, and operating costs for advanced coal and natural gas generating technologies are assumed to be 10 percent lower than reference case levels in 2025. Because learning is assumed to occur in the reference case, costs and performance in the high case are reduced from initial levels by more than 10 percent. Heat rates in the *high fossil technology case* fall to between 17 and 23 percent below initial levels, and capital costs are reduced by 22 to 26 percent between 2005 and 2025, depending on the technology.
- In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the forecast period but remain fixed at the 2005 values assumed in the reference case.

Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cases are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

An additional integrated case was also run to analyze the potential impacts of the EPA's proposed Clean Air Interstate Rule. A detailed description of the rule and a discussion of the sensitivity case results are included in the "Legislation and Regulations" section of this report, pages 34-36.

- The *proposed Clean Air Interstate Rule (pCAIR) case* was run to analyze the potential effects of a rule proposed by the EPA that would cap emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) from electricity generators. The emissions caps in 2010 are 3.86 million short tons SO_2 and 1.6 million tons NO_x. In 2015 the requirements drop to 2.71 million tons SO_2 and 1.33 million tons NO_x. Generators can meet the targets through cap-and-trade programs, or by installing emission control technologies.

Renewable Fuels Cases

In addition to the *AEO2005* reference case, three integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less and more aggressive improvement in renewable technologies and the extension of existing production tax credits for wind and other renewables through 2015. The cases are as follows:

- In the *low renewables case*, capital costs, operations and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2005 levels through 2025.
- In the *high renewables case*, the levelized costs of energy for nonhydroelectric generating technologies using renewable resources are assumed to decline, to 10 percent below the reference case costs for the same technologies in 2025. For most renewable resources, lower costs are accomplished by reducing the capital costs of new plant construction. To reflect recent trends in wind energy cost reductions, however, it is assumed that wind plants ultimately achieve the 10-percent cost reduction through a combination of performance improvement (an increased capacity factor) and capital cost reductions. Biomass supplies are also assumed to be 10 percent greater for each supply step. Annual limits are placed on the development of geothermal sites, because they require incremental development to assure that the resource is viable. In the *high renewables case*, the annual limits on capacity additions at geothermal sites are raised from 25 megawatts per year through 2015 to 50 megawatts per year for all forecast years. All other cases are assumed to retain the 25-megawatt limit through 2015. Other generating technologies and forecast assumptions remain unchanged from those in the reference

case. In the *high renewables case*, the rate of improvement in the recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed, and cellulosic ethanol production is assumed to capture a higher share of the renewable transportation fuels market, resulting in increased cellulosic ethanol supply compared with the reference case.

- Under the Working Families Tax Relief Act of 2004, the production tax credit for wind and some biomass has been extended to plants in service by December 31, 2005. It has also been expanded under the American Jobs Creation Act of 2004 to include other renewable resources. Although the credit has been allowed to expire and then retroactively extended several times, *AEO2005* does not assume its extension beyond 2005, consistent with the approach generally taken toward public policy in the forecast. The *PTC extension case*, discussed in "Issues in Focus," pages 58-62, assumes the extension of the PTC through 2015, as expanded in current law. All technology and cost assumptions are otherwise the same as in the *AEO2005* reference case.

Oil and Gas Supply Cases

Two alternative technology cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. A third case examines the impacts of potential obstacles that may restrict delivery of domestic and foreign natural gas supplies.

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas in the *AEO2005* reference case were increased by 50 percent relative to the reference case. A number of key exploration and production technologies for unconventional natural gas were also increased by 50 percent in the *rapid technology case*. Key Canadian supply parameters were also increased to simulate the assumed impacts of more rapid oil and gas technology penetration on the Canadian supply potential. All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in *Assumptions to the Annual Energy Outlook 2005*, which is available at web site www.eia.doe.gov/oiaf/aeo/assumption/.
- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas in the *AEO2005* reference case were reduced by 50 percent. A number of key exploration and production technologies for unconventional natural gas were also reduced by 50 percent in the *slow technology case*. Key Canadian supply parameters were also increased to simulate the assumed impacts of slow oil and gas technology penetration on Canadian supply potential. All other parameters in the model were kept at the reference case values.
- The *restricted natural gas supply case* acknowledges that the future supply of natural gas could be more constrained than is projected in the reference case, both because of public opposition to the construction of large new natural gas projects, and because the future rate of technological progress could be significantly lower than the historic rate. The *restricted natural gas supply case* incorporates three assumptions: (1) the Alaska natural gas pipeline is *not* built before 2025; (2) all proposed expansions at existing LNG terminals are constructed, but *no* new U.S. LNG regasification terminals are built during the forecast unless they are already fully permitted and under construction; and (3) the future rate of technological progress for oil and gas exploration and development is one-half the historic rate, as specified in the *slow technology case*.

Petroleum Market Cases

Two petroleum market cases were developed and analyzed. The first evaluates the impact of the EPA's new nonroad diesel rule on diesel consumption and prices. The second case is part of the *advanced renewable case*, which evaluates the impact of more optimistic assumptions about biomass supplies on the production and use of cellulosic ethanol.

- The impacts of the new 500 ppm and 15 ppm low sulfur diesel rule on nonroad diesel markets have been implemented in NEMS and are incorporated

in the *AEO2005* reference case. To establish a basis for comparison, the *nonroad diesel emissions rule case* was developed, excluding the impacts of the rule, as discussed in "Legislation and Regulations," pages 14-17.

- The *high renewables case* uses more optimistic assumptions about the availability of renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price earlier than in the reference case. Commercialization of cellulosic ethanol follows the same path from year to year as the reference case but begins in 2006 rather than 2010.

Coal Market Cases

No alternative cases were run for coal markets in *AEO2005*.

Notes

[1] Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004).

[2] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003) (Washington, DC, December 2004).

[3] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the PMM projection.

[4] Jet Information Services, Inc., *World Jet Inventory Year-End 2003* (Woodinville, WA, March 2004), and personal communications with Bill Francoins at Jet Information Services and Thomas C. Hoang at Boeing.

[5] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[6] The hurdle rate for a coal-to-liquids (CTL) plant is assumed to be 12.3 percent because of the higher economic risk involved in this technology.

[7] For gasoline blended with ethanol the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be extended through 2025, based on the fact that the ethanol tax credit has been continuously in force for the past 25 years and was just extended recently by the American Jobs Creation Act of 2004 from 2007 to 2010.

[8] High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

[9] High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

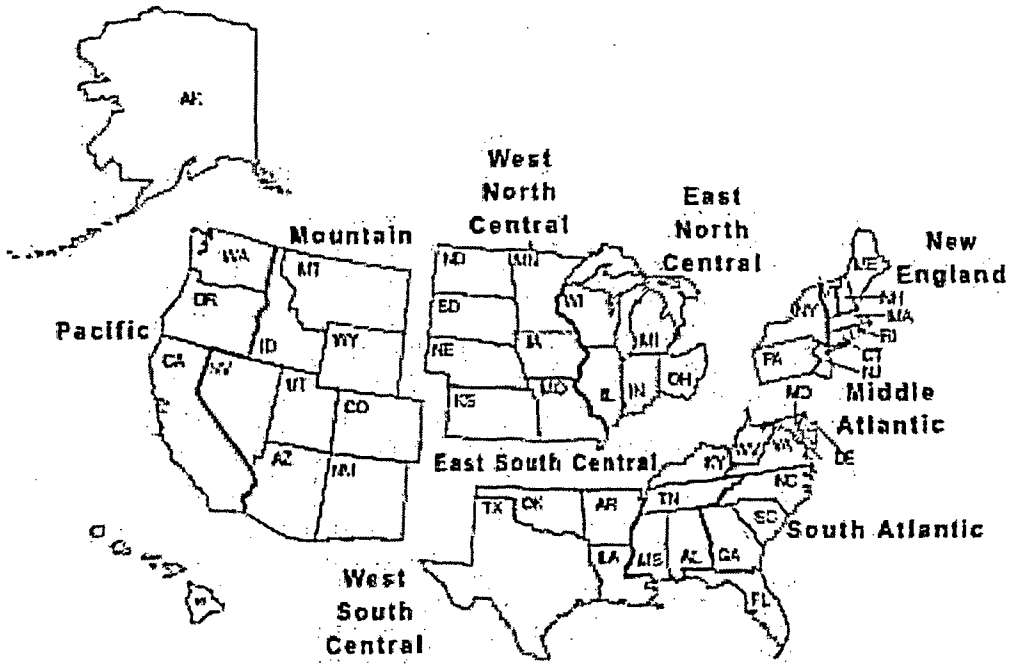
[10] These assumptions are based in part on Energy Information Administration, *Industrial Model—Updates on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001).

[11] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).

[12] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

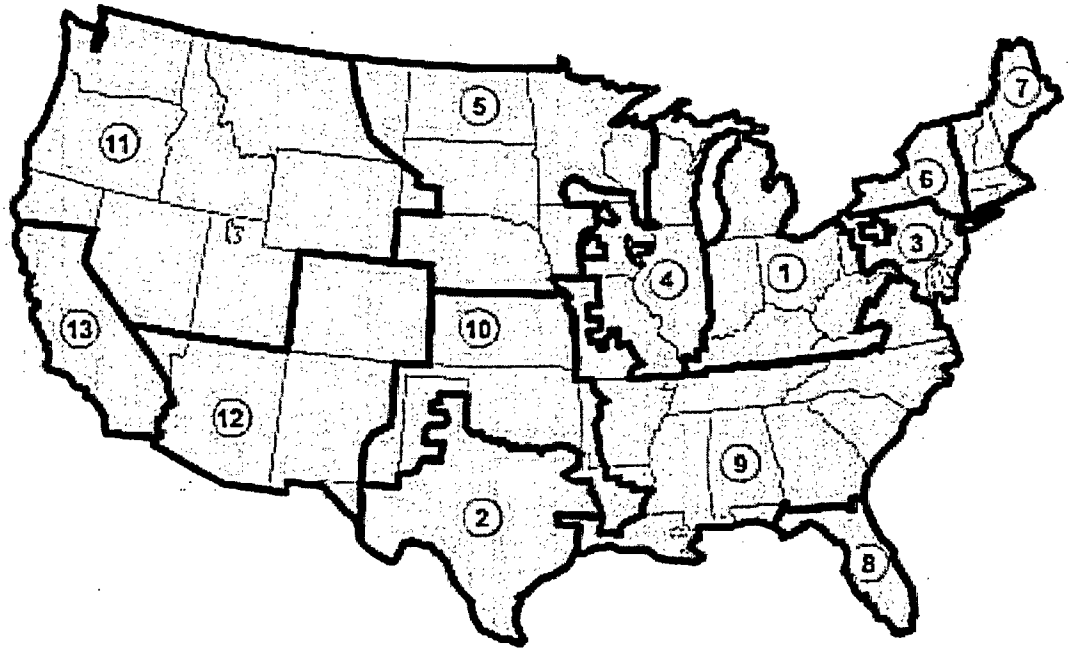
Regional Maps

G1. United States Census Divisions



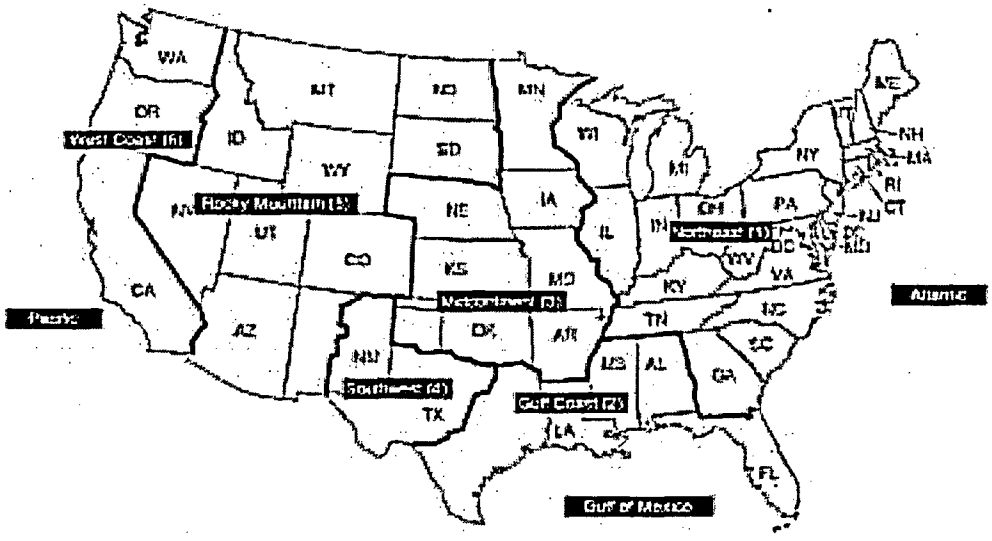
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

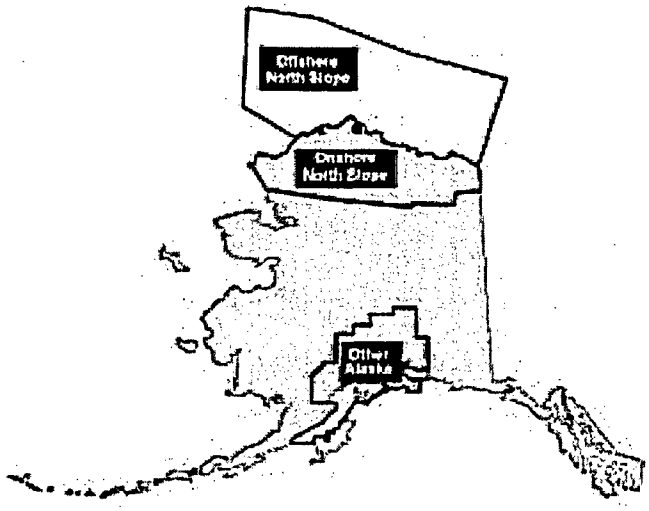
G2. Electricity Market Module Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6 New York (NY)
7 New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWP)
12 Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

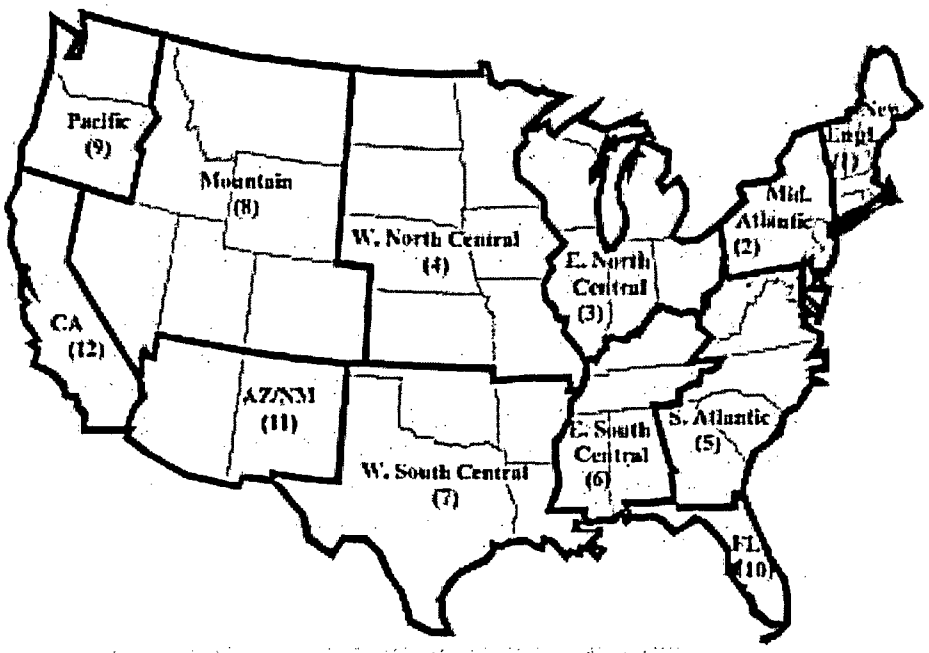
G3. Oil and Gas Supply Model Regions





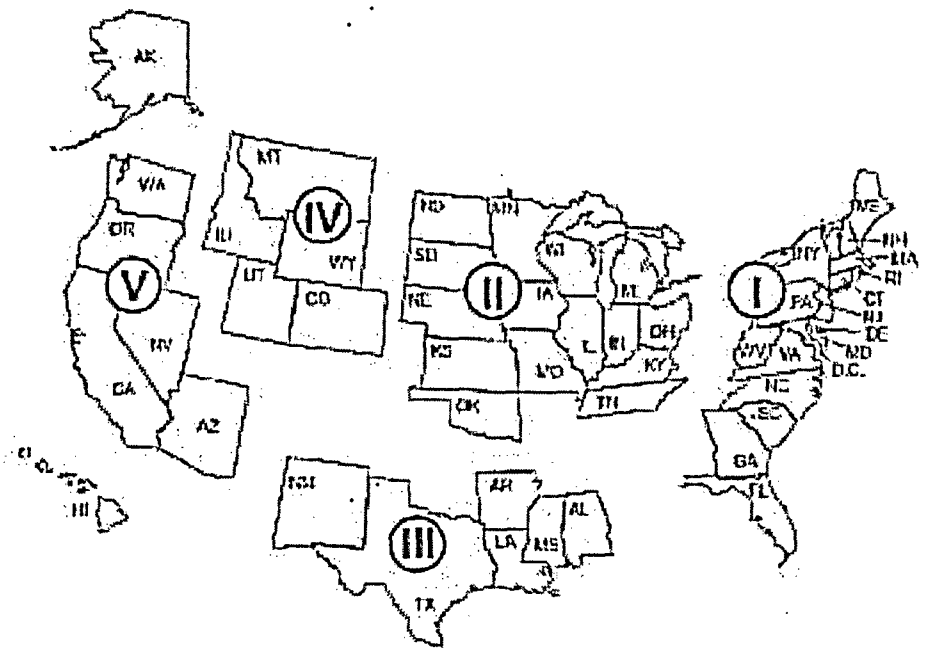
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

G4. Natural Gas Transmission and Distribution Model Regions



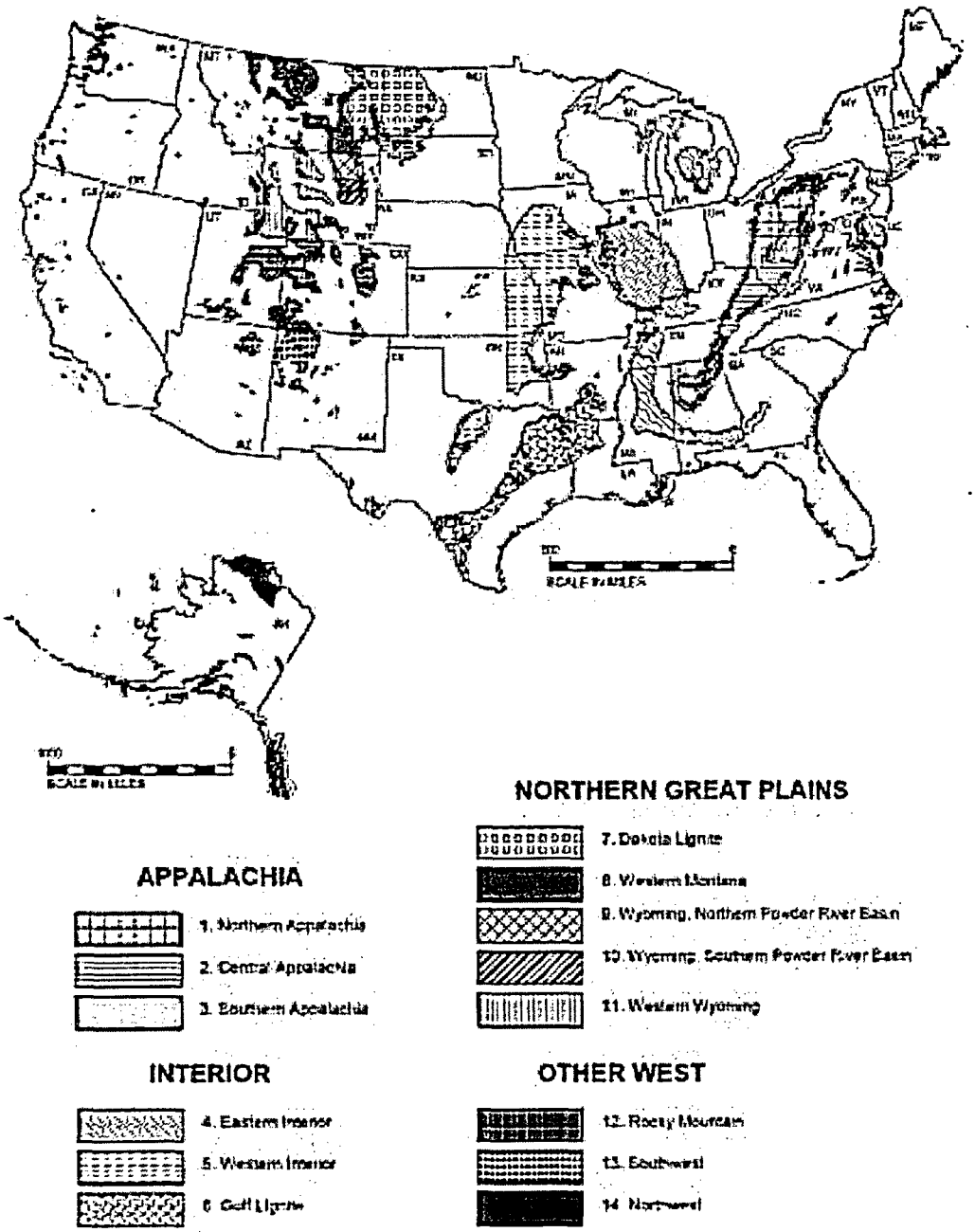
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

G5. Petroleum Administration for Defense Districts

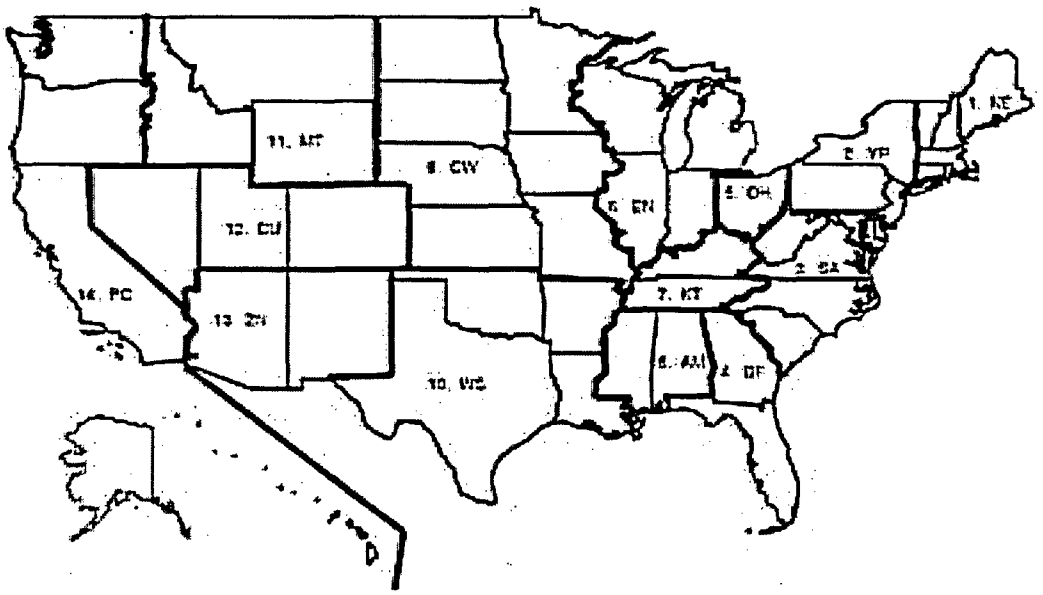


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

G6. Coal Supply Regions



G7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

Appendix H
Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	20.861
Consumption	million Btu per short ton	20.754
Coke Plants	million Btu per short ton	27.425
Industrial	million Btu per short ton	22.468
Residential and Commercial	million Btu per short ton	24.916
Electric Power Sector	million Btu per short ton	20.381
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	25.972
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports	million Btu per barrel	5.975
Petroleum Products		
Consumption[2]	million Btu per barrel	5.345
Motor Gasoline[2]	million Btu per barrel	5.194
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.825
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas[2]	million Btu per barrel	3.612
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[2]	million Btu per barrel	5.533
Unfinished Oils	million Btu per barrel	5.825
Imports[2]	million Btu per barrel	5.435
Exports[2]	million Btu per barrel	5.846
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.735
Natural Gas		
Production, Dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,027
End-Use Sectors	Btu per cubic foot	1,029
Electric Power Sector	Btu per cubic foot	1,020
Imports	Btu per cubic foot	1,023
Exports	Btu per cubic foot	1,010
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.
[1]Coal conversion factors vary from year to year. Values correspond to those published by EIA for 2003 and may differ slightly from model results.
[2]Conversion factors vary from year to year. 2010 values are reported.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), and EIA, AEO2005 National Energy Modeling System run AEO2005.D102004A.

The Energy Information Administration
2005 EIA Midterm Energy Outlook and Modeling Conference

Renaissance Hotel, Washington, DC — *April 12, 2005*

8:30 a.m. - 8:45	**Opening Remarks** - ***Guy F. Caruso, Administrator***, Energy Information Administration
8:45 a.m. - 9:15	**Overview of the *Annual Energy Outlook 2005* - *John Conti, Director***, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:15 a.m. - 10:15	**Keynote Address: International Oil Markets** - ***Speaker to be announced***
10:30 a.m. - 12:00	**Concurrent Sessions A**
	1. The Midterm Outlook for Conventional International Oil Supply, Demand, and Prices: Have the Fundamentals Changed?
	2. Siting Issues in the Development of U.S. LNG Receiving Terminals
	3. Is There a Future for Nuclear Power in the U.S.?
1:15 p.m. - 2:45	**Concurrent Sessions B**
	1. Adaptation of U.S. Refineries to Market Challenges
	2. Unconventional Gas Production: Challenges, Successes, and Future Outlook
	3. Power Sector Emissions Issues
3:00 p.m. - 4:30	**Concurrent Sessions C**
	1. World Outlook for Unconventional Oil Production
	2. When Should We Expect To See Hydrogen Vehicles?
	3. State Incentives for Renewable Energy: Successes and Challenges

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The conference will be held at the *Renaissance Hotel*, (202) 898-9000. The *Renaissance Hotel* is located at 999 Ninth Street, NW, Washington, DC 20001, near the Gallery Place Metro station.

Information

For information, contact Peggy Wells, Energy Information Administration, at (202) 586-8845, peggy.wells@eia.doe.gov.

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Phone: (202) 586-8845
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Please indicate which sessions you will be attending:

- ☐ Opening Remarks/Overview/Keynote Address

Concurrent Sessions A

- ☐ Midterm Outlook for Conventional International Oil Supply, Demand, and Prices
- ☐ Siting Issues in the Development of U.S. LNG Receiving Terminals
- ☐ Is There a Future for Nuclear Power in the U.S.?

Concurrent Sessions B

- ☐ Adaptation of U.S. Refineries to Market Challenges
- ☐ Unconventional Gas Production: Challenges, Successes, and Future Outlook
- ☐ Power Sector Emissions Issues

Concurrent Sessions C

- ☐ World Outlook for Unconventional Oil Production
- ☐ When Should We Expect To See Hydrogen Vehicles?
- ☐ State Incentives for Renewable Energy: Successes and Challenges

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