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Quality

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Preface

Electric Power Annual, Volumes I and II

The *Electric Power Annual* is published in two volumes. Volume I, released August 2001, contains 2000 data on U.S. electric utility net generation; fossil fuel consumption, stocks, receipts, and cost; preliminary data on generating capability and planned additions; and estimated retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold. Also included in Volume I is information on capability sold by utilities to nonutilities, generating capability additions and generating capability retirements.

Volume II contains annual summary statistics for the electric power industry, including information on both electric utilities and nonutility power producers. Included are data for electric utility retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold; financial statistics; environmental statistics; power transactions; and demand-side management. Also included are data for U.S. nonutility power producers on installed capacity; gross generation; emissions; and supply and disposition of energy.

The *Electric Power Annual 2000, Volume II* presents a summary of electric power industry statistics at national, regional, and State levels. The objective of the publication is to provide industry decisionmakers, government policymakers, analysts, and the general public with historical data that may be used in understanding U.S. electricity markets. The *Electric Power Annual, Volume II* 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, Volume II* are researchers, analysts, and individuals with policymaking and decision-making responsibilities in electric utility companies or other energy concerns. Other users include financial and investment institutions, economic development organizations, special interest groups, lobbyists, electric power associations, and the news media.

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

Comparison to the Annual Energy Review

The Energy Information Administration (EIA) changed how it estimates and presents data on the fuels used to produce electricity. The purpose of these changes is to improve the data quality, ensure that the data are reported consistently throughout EIA publications, and give analysts a better understanding of how fuels are used -- whether in plants that only produce electricity (electricity-only plants) or in plants that produce electricity and some form of thermal energy (combined-heat-and-power plants). The EIA undertook an extensive review of reported data for nonutility power producers. This has resulted in revisions to historical data in this publication for the years 1996 through 1999 previously reported.

The data in this publication are the same as the data published in the 2001 Annual Energy Review (AER). The 1999 and 2000 consumption in AER Table 8.3e, "Consumption of Combustible Fuels for Electricity Generation and Useful Thermal Output at Electricity-Only and Combinted-Heat-and-Power Plants by Sector, 1989-2001," are the same as the the consumption in this publication presented in Table 1, "Electric Power Industry Summary for United States, 1999 and 2000." Additionally, the 1999 and 2000 generation in AER Table 8.1, "Electricity Overview, 1949-2001," and the 1999 and 2000 total generating capacity in the AER Table 8.7a, "Electric Net Summer Capacity: Total (All Sectors), 1949-2001," are the same as the generation and generating capacity presented in Table 1.

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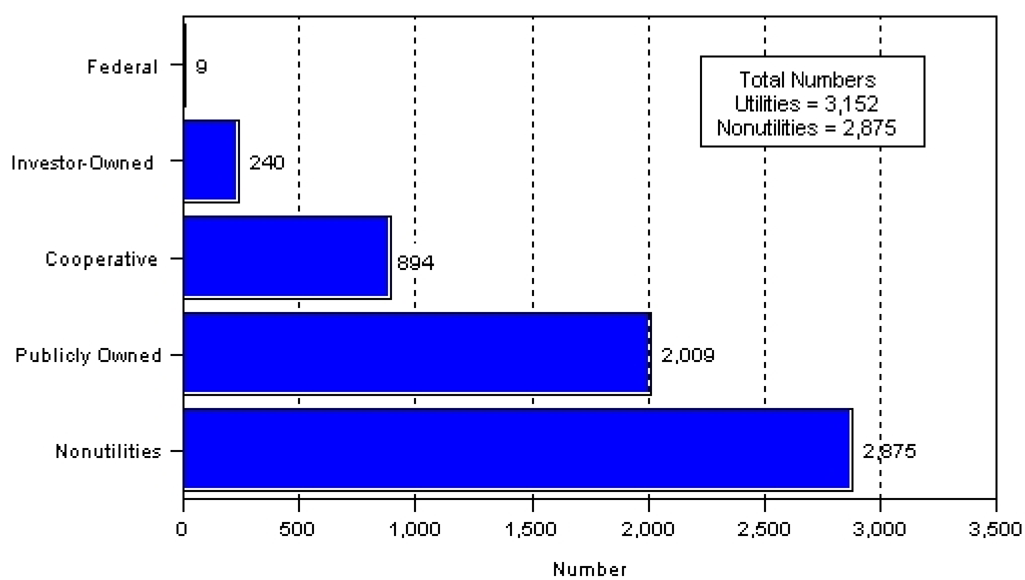
The U.S. Electric Power Industry at a Glance

Industry Profile

The electric power industry in the United States is composed of traditional electric utilities and non-traditional entities, including power marketers and non-utility power producers. In this report, the traditional electric utilities are investor-owned, publicly owned, cooperative, and Federal utilities. They are defined as any person, corporation, municipality, State, political subdivision or agency, irrigation project, Federal power administration, or other legal entity that is primarily engaged in the retail or wholesale sale, exchange, and/or transmission of electric energy. Historically, they have generally been vertically integrated companies that provide for generation, transmission, distribution, and/or energy services for all customers in a designated service territory. However, the industry is currently changing from this vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation.[1]

There are more than 3,100 electric utilities (excluding power marketers) in the United States. Additionally, power marketers, which buy and sell electricity but generally do not own or operate generation, transmission, or distribution facilities, are considered electric utilities. Currently, over 400 power marketers have filed rate tariffs with the Federal Energy Regulatory Commission (FERC) to sell wholesale electric power. However, fewer than one-third of those have actively engaged in wholesale trade. Nonutility power producers are defined as any person, corporation, municipality, State, political subdivision or agency, Federal agency, or other legal entity that is either: (1) a cogeneration qualifying facility under the Public Utilities Regulatory Policies Act of 1978 (PURPA), (2) a small power producer qualified under PURPA that provides at least 75 percent of its total energy input in the form of renewable resources, (3) an exempt wholesale generator (EWG) under the Energy Policy Act of 1992 (EPACT), (4) a cogenerator non-qualifying facility, or (5) an independent power producer (IPP). There are approximately 2,875 nonutility power producers in the United States.

Figure 1. Composition of the Electric Power Industry in the United States, 2000



Notes: ! Data are final. ! Power marketers, Puerto Rico, and U.S. Territories are not included. ! Nonutilities represent the number of generating facilities, as these facilities are generally incorporated, and each is required to file Form EIA-860B.
Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," Form EIA-860B, "Annual Electric Generator Report – Nonutility."

[1] A detailed discussion covering the background of electric industry deregulation is contained in Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96)(Washington, DC, December 1996).

Traditional Electric Utilities

Investor-Owned Electric Utilities. Investor-owned electric utilities currently account for more than 70 percent of all U.S. electric utility generating capability, generation, sales, and revenue. Investor-owned utilities operate in all States except Nebraska. Like all private businesses, investor-owned electric utilities' objective is to produce a return for their investors. The profits are either distributed to stockholders as dividends or reinvested. Investor-owned electric utilities are granted service monopolies and are obligated to serve all customers in their service areas. As franchised monopolies, these electric utilities are regulated and required to charge reasonable and comparable prices to similar classifications of consumers and to give consumers access to services under similar conditions. Most investor-owned electric utilities are operating companies that provide basic services for the generation, transmission, and distribution of electricity. The majority of investor-owned electric utilities perform all three functions. As the industry becomes competitive, utilities are organizing generation, transmission, distribution, and energy services into separate business units, and prices for these functions are being unbundled.

Publicly Owned Electric Utilities. Publicly owned electric utilities in the United States are nonprofit government agencies established to serve their communities and nearby consumers at cost, returning excess funds to the consumer in the form of community contributions, economic and efficient facilities, and reduced rates. Publicly owned electric utilities include municipals, public power districts, State authorities, irrigation districts, and other State organizations. Most municipal electric utilities simply distribute power, although some large ones produce and transmit electricity as well. They obtain their financing from municipal treasuries and from revenue bonds secured by proceeds from the sale of electricity. Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California. Voters in a public power district elect commissioners or directors to govern the district, independent of any municipal government. State authorities, like the Power Authority of the State of New York or the South Carolina Public Service Authority are agencies of their respective State governments. Irrigation districts may have other forms of organization. In the Salt River Project Agricultural Improvement and Power District in Arizona, for example, votes for the Board of Directors are apportioned according to the size of landholdings.

Cooperative Electric Utilities. Cooperative electric utilities in the United States are owned by their members and are established to provide electricity to those members. The Rural Utilities Service (formerly the Rural Electrification Administration) in the U.S. Department of Agriculture was established under the Rural Electrification Act of 1936 with the purpose of extending electric service to small rural communities (usually fewer than 1,500 consumers) and farms where it was relatively expensive to provide service. Cooperatives are incorporated under State law and are usually directed by an elected board of directors, which in turn selects a manager. The National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank for Cooperatives are the most important sources of debt financing for cooperatives. Cooperatives operate in all States except Connecticut, Hawaii, Massachusetts, and Rhode Island and the District of Columbia.

Federal Electric Utilities. Federal electric utilities are primarily producers and wholesalers of electric power and do not produce any profit. As required by law, preference in purchasing the electricity produced is given to publicly owned and cooperative electric utilities and to other nonprofit entities. Wholesale Federal producers include the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the International Boundary and Water Commission. Power produced by these Federal entities is marketed by Federal power marketing administrations in the U.S. Department of Energy: Bonneville, Southeastern, Southwestern, and Western Area Power Administrations. The Federal power marketing administrations operate in all areas except the Northeast, upper Midwest, and Hawaii. The largest producer of Federal electricity, the Tennessee Valley Authority, markets its own power. The Alaska Power Administration operated and distributed power from its own projects and marketed both wholesale and retail electricity. On November 28, 1995, the President signed a bill authorizing the sale of the Alaska Power Administration's projects. Transfer of title to the State of Alaska and three utilities occurred in August 1998.

Power Marketers. Power marketers continue to be a rapidly growing segment of the electric power industry. Like traditional electric utilities, power marketers buy and sell electric power in the wholesale market and fall under FERC's jurisdiction, since they take ownership of power and are engaged in interstate trade. Power marketers differ from traditional electric utilities in that they generally lack both ownership of generation, transmission, or distribution facilities and a designated service territory.

Although the number of registered power marketers continues to grow fewer than one-third of those registered with the FERC have actually conducted wholesale electricity transactions. Many registered power marketers have undertaken only a few transactions, seemingly to test and improve their techniques and procedures and to observe marketplace opportunities.

As the States open retail access for electricity, power marketers are entering these new markets. The State public utility commissions require registration of retail electricity providers, including power marketers and energy service providers.

Many power marketers are affiliated with companies owning reserves of other sources of energy, such as natural gas. An exchange of fuel for electricity known as "tolling" allows a power marketer with access to fuel resources to "rent" a generator from an electric utility, supply fuel to the unit to produce electricity, pay the "rental" fee with a portion of the generated power, and take delivery of the balance for sale to customers.

Nonutility Power Producers

Cogenerator Qualifying Facilities. These are generating facilities that produce electricity and another form of useful thermal energy, usually heat or steam, for industrial processes, or heating/cooling purposes. Cogenerators are qualified under PURPA by meeting certain ownership, operating and efficiency criteria as set forth by the FERC. They are guaranteed that utilities will purchase their output at a price based on the utility's "avoided cost" and will be provided backup service at nondiscriminatory rates.[2]

Small Power Producers. These are also qualified under PURPA by meeting certain ownership, operating, and efficiency criteria as set forth by the FERC. They are distinguishable by their use of renewable resources such as biomass, geothermal, solar, wind, or water as a primary energy source. Renewable resources must provide at least 75 percent of the total energy input. Like cogenerators, they are also guaranteed that utilities will purchase their output based on the utility's "avoided cost" and provide backup service at nondiscriminatory rates.

Exempt Wholesale Generators. EPACT modified the Public Utility Holding Company Act (PUHCA) and created another class of nonutility power producers, EWG. EPACT exempted EWGs from the corporate and geographic restrictions that PUHCA imposed. With this modification, public utility holding companies are allowed to develop and operate independent power projects anywhere in the world.[3] Lacking transmission facilities and selling wholesale only, EWGs are regulated but usually may charge market-based rates. Utilities are not required to purchase their electricity.

Cogenerator Non-Qualifying Facilities. These facilities utilize cogeneration technology and may themselves consume part of the electricity they cogenerate. They are not qualified under PURPA.

Independent Power Producers. IPPs are also considered nonutility power producers in the United States. These facilities are wholesale electricity producers that operate within the franchised service territories of host utilities and are usually authorized to sell at market-based rates. Unlike traditional electric utilities, IPPs do not possess transmission facilities or have retail electric sales.

The Changing Industry

The electric power industry is being transformed from a structure of highly regulated monopolies to one which places growing reliance on competitive markets to establish prices.[4] The implementation of EPACT by the FERC and adoption of retail access plans by a growing number of States are introducing greater competition in the generation and retail supply segments of the industry. EPACT amended the Federal Power Act, authorizing the FERC to order public utilities to provide transmission services for competitive wholesale power purchases and sales. Prior to EPACT, the FERC could not mandate an electric utility to provide wheeling services for wholesale electric trade. This change in the law permits generators to make sales for resale to noncontiguous utilities. In 1996, relying on its authority to prevent undue discrimination in the provision of transmission services, the FERC issued Orders 888 and 889, requiring utilities to file open access transmission tariffs. Order 888 guaranteed suppliers and wholesale purchasers access to transmission-owning utilities. Order 888 also provided for utility recovery of costs that may be stranded as a result of open access. Potentially stranded costs are costs that utilities would have had the opportunity to recover at expected market prices.

Stakeholder disagreements soon arose as to how the FERC should deal with the transition costs associated with the shift to competition. As a result, the Commission's Order on Rehearing (Order No. 888-A) was issued in early 1997. Basically, Order 888-A strives to achieve a balance between the different approaches on how to achieve the recovery of stranded costs. Most critically addressed is how to maintain the financial health of the industry, maintain the regulatory deals concerning large past investments, and avoid shifting the costs to customers that had no responsibility for these stranded costs.

Order 889 requires public utilities that own or operate transmission facilities to establish electronic information systems, known as Open Access Same-time Information Systems (OASIS), to provide all parties identical access to information on available transmission capacity. Order 889 also requires utilities to implement standards of conduct that functionally separate the operation of the transmission system from each utility's wholesale merchant function.

Power pools and groups of utilities in most regions of the United States have responded to the FERC rulemakings by proposing the formation of independent system operators (ISOs) to ensure nondiscriminatory operation of their transmission systems and facilitate the development of regional transmission tariffs. Known as comparable service,

[2] See the chapter, "Nonutility Power Producers," for a description of the benefits under PURPA.

[3] EWGs are not considered electric utilities under PUHCA; they are restricted to selling wholesale power to electric utilities and municipalities. However, EWGs were considered to be electric utilities under the Federal Power Act.

[4] For a further treatise and more detailed information on the transformation of the electric power industry, the reader is referred to the publication Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998,* DOE/EIA-0562(98) (Washington, DC, July 1998).

Order 888 requires utilities owning bulk power transmission facilities to apply any of their own new wholesale sales and purchases of energy over their own transmission facilities the same transmission tariffs that they apply to others. Advantages are expected to arise from the operational efficiencies that result from overseeing a large regional transmission system and from the elimination of multiple tariffs. However, this program is not without its detractors who claim that advantages may still go to vertically integrated utilities who maintain transmission ownership rights, as opposed to nonowners. A possible effect, they assert, is that the ISO will curtail needed future expansion of transmission facilities.

The open access provisions of Order 888 have reduced barriers to FERC approval of market-based rates for wholesale power sales. Since the FERC began approving market-based pricing in 1988, the key impediment has been the potential for utilities to exercise market power through ownership or control of transmission facilities. Filing of an Order 888 open access transmission tariff meets FERC's standards with respect to mitigating market power in transmission. With this barrier removed, the FERC has approved market-based rates for more than 300 utilities and power marketers.

Regional development of ISOs as envisaged by the FERC's 1996 Orders has been uneven. Difficulties in forming multi-State ISOs remain unresolved, and the cumulative effects of changes in patterns of wholesale and retail trade have intensified the burden on the transmission grid. According to the FERC, these developments have completely changed the landscape from the one that it faced at the time Order Nos. 888 and 889 were being developed and pose new regulatory and industry challenges.

The FERC delineated transmission-related impediments to competition in two broad categories:

- impediments consisting of engineering and economic inefficiencies inherent in the current operation that hinder development of fully competitive power markets and impose avoidable costs on consumers, and

- continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission system to favor their own affiliates.

Other shortcomings include complaints with respect to the determination of total transfer capability (TTC) and the available transfer capability (ATC). Inability to determine ATC in a timely fashion impacts on the trades that can be handled on a given system. Similarly, congestion management issues, if not resolved in a timely fashion, inhibit system capability to provide least-cost power.

With a view to alleviate these problems, the FERC took a major step by espousing a proposal to create regional transmission organizations (RTOs). In a Notice of Proposed Rulemaking (NOPR) the Commission proposed to require each public utility that owns, operates, or controls facilities for transmission of electric energy in interstate commerce to make certain filings with respect to the formation of and participation in RTOs. Minimum characteristics and functions that a transmission entity must satisfy to be considered an RTO were also specified. Specifically, the proposed RTOs are required to be independent from market participants and should have appropriate regional scope and configuration together with the authority over transmission facilities to maintain reliability. A voluntary and collaborative process to accommodate regional needs was proposed.

Subsequent to the issuance of the NOPR, the FERC held various public conferences around the country to hear the concerns of interested stakeholders as well as receive inputs from State regulatory agencies on the subject. On the basis of these deliberations, the Commission issued its ruling in Order 2000 on December 20, 1999. In its Order, the Commission adopted a flexible approach that permits different types of RTOs like the non-profit independent system operators and the for-profit transmission companies. The Order also embodies a principle of open architecture and permits RTO members to improve its structure when deemed necessary to meet evolving market needs.

All RTOs are required to abide by four core characteristics and eight key functions. The core characteristics are independence, scope and regional configuration, operational authority, and short-term reliability. The eight key functions are tariff administration and design, congestion management, parallel path flows, ancillary services, OASIS, market monitoring, planning and expansion, and interregional cooperation. Transmission-owning utilities not participating in an ISO must file by October 15, 2000, a proposal to join an RTO. Utilities already members of an ISO were required to file by January 15, 2001. According to the FERC, the proposed RTOs were to be operational by December 15, 2001. The Commission hopes that the RTOs will improve efficiencies in the power grid, remove remaining opportunities for discriminatory transmission practices, lower transaction costs, and facilitate the success of State retail programs.

The Order applies only to those utilities that are under the FERC's jurisdiction. However, there are many segments of the transmission network under the control of utilities that are not under FERC jurisdiction, such as municipals, power districts, State agencies, and cooperatives that are faced with restrictions on usage of electrical facilities funded by tax-exempt bonds. For-profit entities would have access and use of these electrical facilities when they are integrated into an RTO but this is prohibited under tax-exempt finance regulations. In order for these utilities to join, they would either have to refinance these bonds and remove the restrictions or acquire a relief of this tax burden. These concerns are currently under review.

Mergers and acquisitions have been proposed as utilities position themselves for competition. During 2000 there were 9 operational electric utility mergers. Several were cooperatives, positioning themselves for the deregulated market. In December 1996, the FERC revised its merger policy to facilitate decisions on a backlog of merger applications, provide greater certainty to merger applicants, and ensure that merger policies do not impede the development of competitive generation markets. Proponents of mergers cite increased economies of scale through the elimination of duplicate functions, penetration into new and additional customer territory, and the economic and financial advantages that come with increased financial strength and operational size.

EPACT lifted the corporate and geographic restrictions in the PUHCA for a new class of nonutility generators, EWGs. This modification of PUHCA allowed public utility holding companies to develop and operate independent power projects anywhere in the world. Also provided is consumer protection against financial abuses and cross-subsidization between regulated and unregulated utilities. EPACT also amended PURPA by creating inducements for investments in cost-effective improvements in efficiency of power generation and supply. Also added were new rulemaking standards concerning wholesale purchased power. The Federal Power Act of 1935 was amended by broadening when the FERC can order transmission-owning utilities to wheel power and ensuring recovery of the associated costs. Also, the issuance of any order that is inconsistent with State laws governing the retail marketing areas of electric utilities is precluded.

During 2000, the sale of generating units by utilities to nonutility companies decreased. The amount of capability sold to nonutilities during 2000 was 47,710 megawatts. Although the effect of the shift from utility to nonutility ownership of generating units was relatively small at the national level, it could be observed more strongly at the State level when restructuring legislation required or encouraged divestiture of the utility's generating assets. This shift in ownership reflects the sale of plants, as well as unit additions and retirements, during the year.

Electric utilities added 6,928 megawatts of new capability and retired 985 megawatts during 2000. In addition, nonutility companies added 16,525 megawatts of new capability. Ninety-five percent of this new nonutility capability was gas-fired.

Restructuring at both the Federal and State levels is rapidly transforming the generation and retail supply segments of the electric power industry into competitive markets that increasingly will replace State and Federal regulators in setting the price and terms of electric generation and supply services. Legislatures and/or public utility commissions in most States are considering or have approved plans that will allow retail customers direct access to generation markets by allowing customers to choose among competitive suppliers of generation. Some regions may establish generation tracking and disclosure systems, providing consumers the option of purchasing from suppliers of renewable or other preferred types of generation.

A number of States have adopted legislation or approved plans making retail access available to their customers. Pilot programs to initiate and evaluate retail access are being conducted in States where retail access plans are approved or likely to be approved soon. In some jurisdictions, retail access plans face legal challenges related to the recovery of potentially stranded costs and other issues. As of December 2000, 21 States had enacted restructuring legislation. Comprehensive regulatory orders had been issued in 3 States. Legislation was pending, commissions had been established, or investigations were ongoing in the remainder.

The year 2000 was clearly a transition year for the electric industry as the Nation moved State by State toward restructuring. Consolidation through mergers and acquisitions was prominent as industry participants maneuvered, hoping to gain a competitive advantage. Divestiture of generation assets was common as some electric utilities exited the generation business in order to concentrate on the distribution of electricity. Others used the opportunity to purchase divested assets to build a critical mass of generating capability that many think will be necessary to survive what is expected to be a very competitive industry.

The transition from a highly regulated business into a competitive market did encounter a stumbling block in 2000, one that could slow its course and cause some states to reconsider the idea of restructuring--California. In April 1998, California became the first State to restructure its electric industry. Yet, in 2000 there was very little good news concerning restructuring to come out of the State. Rolling blackouts, sky-high electricity prices, and utilities nearing bankruptcy were all linked to the restructuring of California's electric industry. By year-end, re-regulation was a hot topic. In the near term, the attention that was focused on the pitfalls of restructuring sentiment in California affected restructuring in other states. During the year, only two additional States enacted restructuring legislation--Michigan and West Virginia--bringing the year-end total to 23 States and the District of Columbia.[5] In the longer term, California may end up being just a "lesson learned" for the remainder of the States contemplating changes to their electric industry.

[5] United States Department of Energy, Energy Information Administration. Extracted from the Internet at http://www.eia.doe.gov/cneaf/electricity/page/restructure.html, on May 29, 2001.

A Review of 2000

U.S. Electric Utility Statistics

In 2000, the electric power industry experienced continued changes to its sales, finances, power transactions and other industry indicators. The following is a summary of those changes.

Retail Sales and Revenue

In recent years, the Energy Information Administration collected retail sales and revenue information on deregulated markets from retail energy service providers that included the cost of energy to the customer, but not the cost of associated delivery services (i.e., line maintenance, billing, etc.). For the first time, for the year 2000 cycle, the EIA collected information on the revenue received by traditional distribution utilities for delivery services provided to consumers who selected alternate energy suppliers in State "retail wheeling" programs. Thus it is now possible to provide sales and complete revenue data for the approximately 1.5 million consumers who participated in those programs in 2000. Statistics referred to in this text include both fully bundled and unbundled consumers combined (see Tables 2 through 2d), as well as bundled customers only (Tables 3a through 7). Some consumer counts, sales and revenue data provided for unbundled consumers are adjusted by the EIA to account for probable underreporting (for a discussion of this adjustment, and more information on sales in competitive retail markets, see Electric Sales and Revenue 2000, Appendix C).

Electricity sales to full-service and unbundled consumers increased by 3.3 percent to over 3,421 billion kilowatthours (adjusted) in 2000. Sales by competitive energy service providers in State-level "customer choice" programs increased by 47 percent, from 76.2 billion kilowatthours in 1999 to 111.9 billion kilowatthours (adjusted) in 2000. Total retail revenue received by electric utilities and energy service providers increased to over $233 billion (adjusted).

In 2000, full-service sales by traditional distribution utilities continued to account for approximately 97 percent of total retail electricity sales. Sales by traditional distribution utilities increased from 3,236 billion kilowatthours in 1999 to 3,310 billion kilowatthours in 2000, an increase of 2.3 percent. The largest increases in electricity consumption in 2000 occurred in the southern-tier States mostly unaffected by deregulation, but with heavy air conditioner loads (i.e., Texas, Louisiana, Mississippi, Alabama, Florida, and Georgia). Revenue from retail sales by traditional utilities increased from $215 billion in 1999 to $224 billion in 2000.

The national average revenue in cents per kilowatthour increased from 6.66 in 1999 to 6.78 in 2000. This was the first year an increase has been recorded in the average revenue per kilowatthour since the early-nineties. Each major consumer sector, including industrial, experienced increases in the average cost of power. Industrial average revenue increased from 4.43 cents per kilowatthour for fully-bundled consumers to 4.57 cents. However, nominal industrial rates remain the lowest since 1981, and real industrial rates remained among the lowest since 1973.

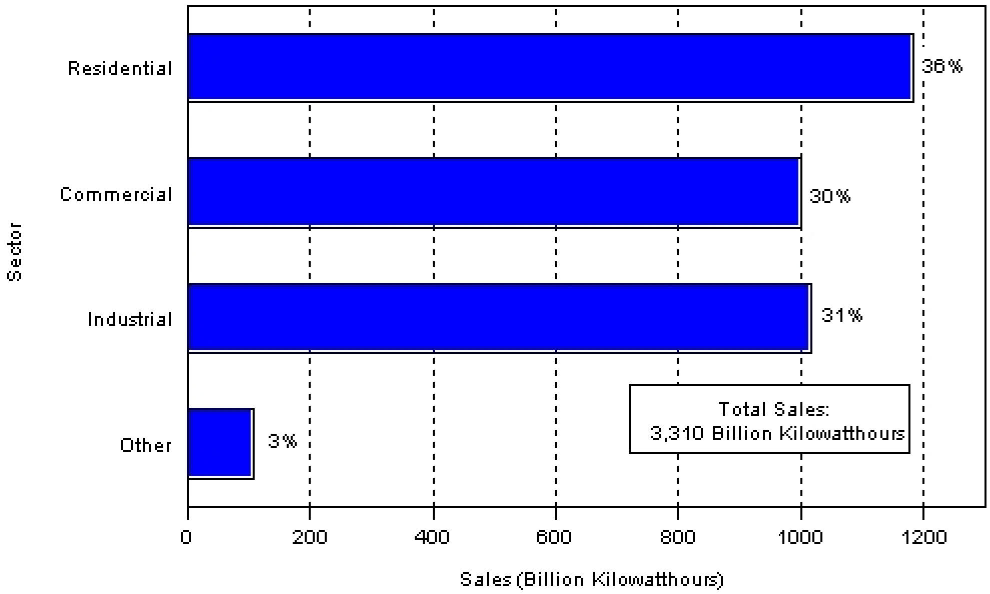
Financial Statistics. Electric operating revenues for the major investor-owned electric utilities were up $17.1 billion to $214.7 billion in 2000. Electric utility operating expenses, led by combined increases in operation and maintenance expenses, were up $24.0 billion. As a result, electric operating income declined from 1999. This increase in expenses caused net income to decline 22.3 percent to $13.3 billion. Dividends declared on preferred stock continued to decline, with the 2000 amount less than half that reported in 1996. Common dividends fell 10.8 percent to $16.7 billion. The profit margin fell to 5.64 percent, and the current assets to liabilities ratio of 0.85 dropped below the 1996 level.

In 2000, the major investor-owned segment continued to position itself in response to restructuring of the industry. Net electric utility plant continued its decline, dropping 1.0 percent to $307.3 billion. This is 15.5 percent less than the $363.9 billion reported in 1996. Accumulated depreciation continued its increase to $277.8 billion. Other property and investments increased 4.5 percent, whereas deferred debits dropped less than 0.1 percent. Current and accrued assets increased 38.1 percent. Total capitalization declined to $341.2 billion primarily due to the $5.0 billion decrease in common stock equity. A $28.0 billion increase occurred in current and accrued liabilities.

In 2000, the major publicly owned generator electric utilities had a combined operating revenue of $31.8 billion, up by 19.0 percent. Generator electric utility operating expenses increased 23.4 percent, resulting in an increase in net income of 469 million. Total assets for publicly owned generator electric utilities rose by $11.3 billion, ending at $127.5 billion. The electric utility plant per dollar of revenue ratio was 3.5 in 2000.

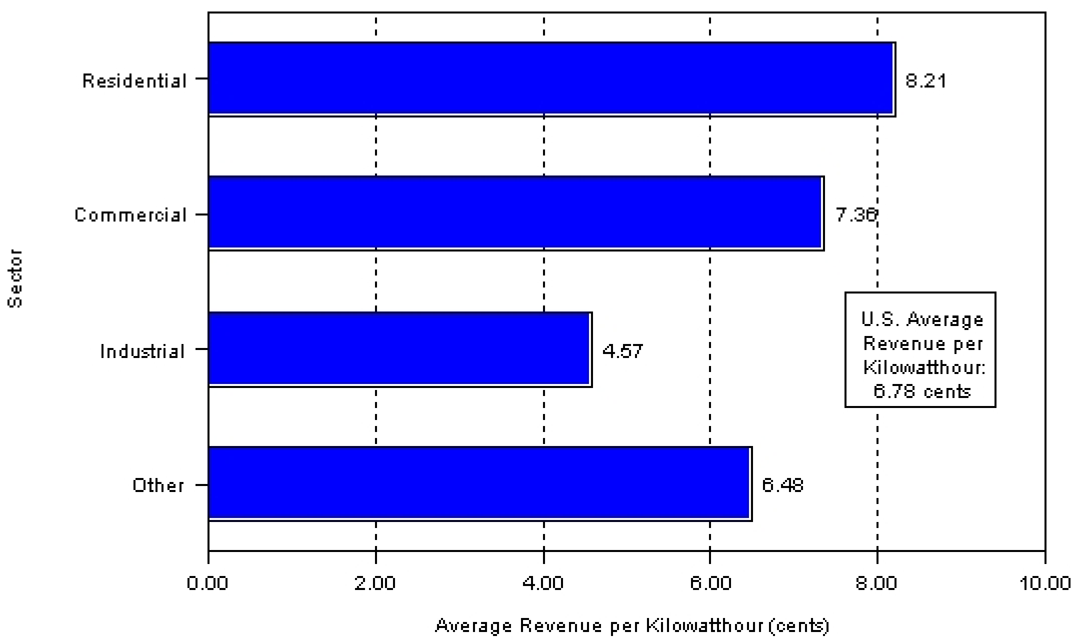
In 2000, the major publicly owned nongenerator electric utilities had a combined operating revenue of $9.9 billion, a 5.9 percent increase over 1999. Nongenerator electric utility operating expenses increased by 7.0 percent to end the year at $9.4 billion. Net income for nongenerators decreased slightly to $0.5 billion. Total assets for nongenerator electric utilities increased by 10.3 percent to end the year at $14.6 billion. The electric utility plant per dollar of revenue ratio increased to 1.3 in 2000.

Figure 2. U.S. Electric Utility Sales to Bundled Ultimate Consumers by Sector, 2000



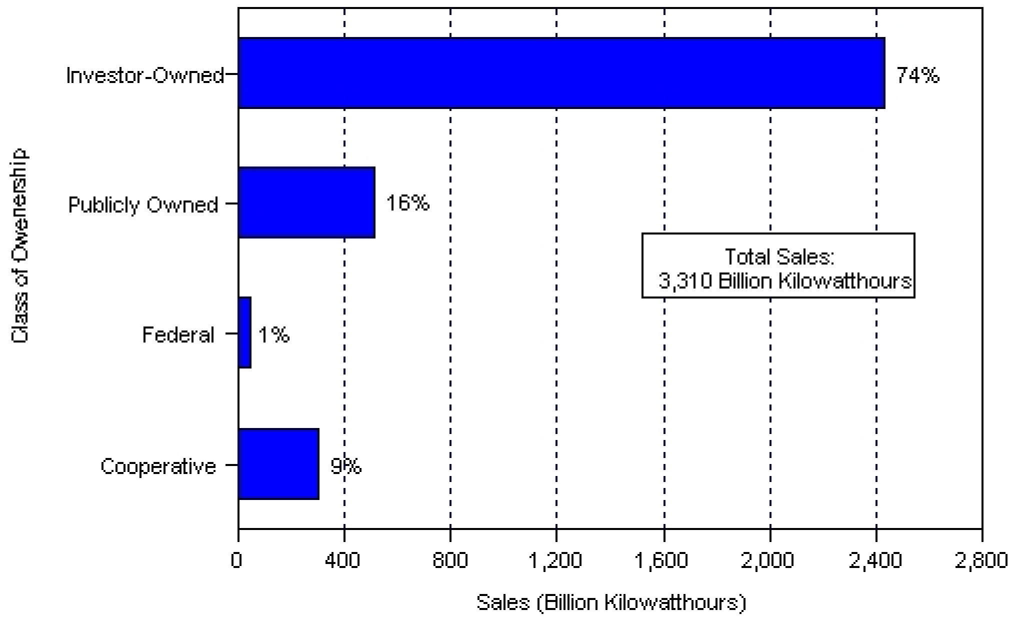
Notes: ! Data are final. ! Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. ! Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 3. U.S. Electric Utility Average Revenue per Kilowatthour by Sector (Bundled Consumers), 2000



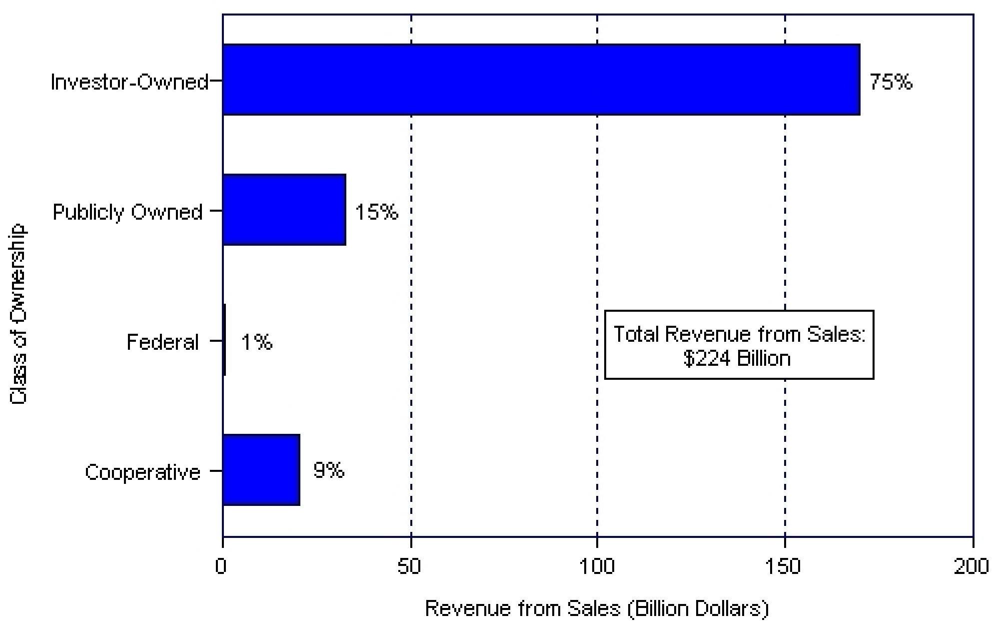
Notes: ! Data are final. ! Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 4. U.S. Electric Utility Sales to Bundled Ultimate Consumers by Class of Ownership, 2000



Notes: ! Data are final. ! Totals may not equal sum of components because of independent rounding.
Source Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 5. Revenue from U.S. Electric Utility Sales to Bundled Ultimate Consumers by Class of Ownership, 2000



Notes: ! Data are final. ! Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Environmental. Flue gas desulfurization (FGD) equipment, sometimes referred to as scrubbers, uses chemicals such as lime to remove sulfur oxides from the combustion gases of boilers before the gases are discharged into the atmosphere. In 2000, there were 192 generators connected to scrubbers at U.S. power plants, compared with 192 in 1999 and 150 in 1989. The average sulfur content of coal delivered to all U.S. electric utility plants decreased slightly from 1.01 percent by weight in 1999 to 0.93 percent by weight in 2000.[6]

Power Transactions. On a national basis in 2000, wholesale power receipts (purchased power plus exchanges received and wheeling received) increased by 436 billion kilowatthours to reach 3,000 billion kilowatthours. Sales to ultimate consumers totaled 3,421 billion kilowatthours (including sales by retail power marketers), of which 1,716 billion kilowatthours or 48 percent was from wholesale trade with other electric utilities (requirement and nonrequirement sales for resale). To supply electric energy in 2001, electric utilities had planned capacity resources on hand of 808 million kilowatts, and 827 million kilowatts for the winter, resulting in national capacity margins of 16.5 percent and 30.4 percent, respectively.

In 2000, the noncoincidental peak load at electric utilities in the contiguous United States showed an increase of 0.6 percent, from 681 to 686 million kilowatts for the summer. The winter peak load was 592 million kilowatts, increasing 21 million kilowatts from 1999 which represented a change of less than 4.0 percent. Both the summer and winter peak loads for the contiguous United States were projected for 2001 to grow to 709 and 606 million kilowatts, respectively. By the year 2005, the noncoincidental peak load is expected to be above the 2000 actual by almost 83 million kilowatts for the summer and 60 million kilowatts for the winter.

Demand-Side Management. In 2000, 962 electric utilities reported having demand-side management (DSM) programs. Of these, 516 were classified as large, and 446 were classified as small utilities. This is an increase of 114 utilities utilities from 1999. DSM costs were slightly increased from 1999 at $1.56 billion.

Energy savings for the 516 large electric utilities increased to 53.7 billion kilowatthours, 2.1 billion kilowatthours more than in 1999. These energy savings represent 1.6 percent of total annual electric sales of 3,421 billion kilowatthours to ultimate consumers in 2000.

Actual peak load reductions for large utilities decreased in 2000 to 22,901 megawatts. Potential peak load reductions of 41,369 megawatts were a decrease of 2,201 megawatts from 1999.

In 2000, incremental energy savings for large utilities were 3.3 billion kilowatthours, incremental actual peak load reductions were 1,640 megawatts, and incremental potential peak load reductions were 3,159 megawatts.

U.S. Nonutility Generating Facility Statistics

Generation. In 2000, U.S. nonutility generating facilities generated 828 billion kilowatthours of electricity. U.S. nonutility generating facilities received 95 billion kilowatthours from, and delivered 660 billion kilowatthours to, electric utilities and other end users. Nonutility power producers delivered approximately 79.6 percent of their gross generation to electric utilities and other end users and used 263 billion kilowatthours for their own power plant operations and industrial processes. More than one-fourth of national nonutility production of electricity occurred in California and Pennsylvania, with 127 and 111 billion kilowatthours, respectively.

Gross generation for nonutility generating facilities was 52.6 percent higher in 2000 than a year earlier. Slightly more than 40 percent of the generation by nonutility generating facilities was gas-fired, with generation from coal accounting for 34.6 percent of the total. Of the total nonutility generation, 354 billion kilowatthours were from qualifying facilities, approximately 42.7 percent of the total. (See the Chapter titled "Nonutility Power Producers" for a definition of these facilities.) The largest share of gross generation was produced by facilities in the Middle Atlantic Census Division (New Jersey, New York, and Pennsylvania), followed by the Pacific Census Division (Alaska, California, Hawaii, Oregon, and Washington). The transportation and public utilities sector dominates electric generation, with the largest share in the Middle Atlantic Census Division. For the second largest sector, the manufacturing sector is concentrated in the West South Central Census Division, Middle Atlantic Census Division, and South Atlantic Census Division (Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia) where there is a large potential for cogeneration in both the refining and the paper and pulp industries.

Capacity. The total installed capacity of nonutility generating facilities was 228,594 megawatts at the end of 2000, 42.4 percent more than in 1999. The restructuring of the electric power industry has resulted in 50,884 megawatts during 1999 and 47,710 megawatts during 2000 of net summer capability that has been sold (or reclassified) to nonutilities. Nonutility capacity in 2000 was equivalent to 25.3 percent of the total U.S. electric industry capacity.

Of all energy sources, gas and other gas accounted for the largest amount of nonutility capacity. The Pacific

[6] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1999 Tables,* DOE/EIA-0191(99) (Washington DC, 2000).

Census Division accounted for the largest percent of that gas-fired capacity. The second largest share of nonutility capacity was provided by coal, followed by petroleum only and natural gas.

The greatest number (527) of nonutility generating facilities was in the Pacific Census Division, with a capacity of 34,929 megawatts. In the Pacific Census Division, California dominated because the State actively promoted alternative energy sources in the 1970's and 1980's by providing incentives to nontraditional electricity producers. Many of these incentives have since expired or been rescinded, but they served to assist in the development of nonutility generation. The second greatest number (447) of nonutility generating facilities was in the Middle Atlantic Census Division where restructuring of the electric power industry has resulted in the selling of plants from electric utilities (regulated) to nonutilities (unregulated) in all three States of New York, Pennsylvania, and New Jersey.

Consumption. In 2000, consumption by nonutilities included 3,634 billion cubic feet of natural gas, 156 million short tons of coal, and 93 million barrels of petroleum. Compared to 1999, consumption increased 105.2 percent for coal, 13.8 percent for gas, and 10.0 percent for petroleum.

Table 1. Electric Power Industry Summary Statistics for the United States, 1999 and 2000

Item	1999 R	2000	Percent Change
Electric Power Industry[1]			
Generating Capability (megawatts)[2]	785,927	812,667	–3.4
Net Generation (million kilowatthours)	3,694,810	3,802,123	2.9
Electric Utilities			
Generating Capability (megawatts)[2] [5]	[9] 639,324	604,319	–5.5
Coal	277,780	260,990	–6.0
Petroleum Only	31,742	25,823	–18.6
Gas Only	31,886	32,125	0.7
Dual Fired (gas and petroleum)	108,716	106,806	1.8
Nuclear	95,030	85,968	–9.5
Hydroelectric Pumped Storage	18,945	18,020	–4.9
Hydroelectric (conventional)	74,122	73,738	–.5
Other Renewable			
Geothermal	273	273	.0
Biomass[6]	571	505	-11.6
Wind	29	54	86.2
Photovoltaic	5	5	.0
Other[23]	225	13	–94.2
Net Generation (million kilowatthours)	3,173,674	3,015,383	–5.0
Coal	1,767,679	1,696,619	–4.0
Petroleum[7]	86,929	72,180	–17.0
Gas	296,381	290,715	–1.9
Nuclear	725,036	705,433	–2.7
Hydroelectric Pumped Storage[8]	–5,982	–4,960	–17.1
Hydroelectric (conventional)	299,914	253,155	–15.6
Other Renewable			
Geothermal	1,698	151	–91.1
Biomass[6]	1,992	2,058	3.3
Wind	23	29	26.1
Photovoltaic	3	3	.0
Consumption			
Coal (million short tons)	894	859	–3.9
Petroleum (million barrels)[10]	153	126	–17.6
Gas (billion cubic feet)	3,113	3,043	–2.2
Stocks (Year End)			
Coal (million short tons)	129	90	–30.2
Petroleum (million barrels)[11]	44	30	–31.8
Receipts			
Coal (million short tons)	908	790	–13.0
Petroleum (million barrels)[12]	131	100	–23.7
Gas (billion cubic feet)[13]	2,811	2,632	–6.4
Cost (cents per million Btu)[14]			
Coal	121.6	120.0	–1.3
Petroleum[15]	252.7	445.0	76.1
Gas	257.4	430.2	67.1
Sales To Ultimate Consumers(million kilowatthours)[16]	3,235,899	3,309,550	2.3
Residential	1,140,761	1,183,137	3.7
Commercial	970,601	1,000,865	3.1
Industrial	1,017,783	1,017,723	.0
Other[17]	106,754	107,824	1.0
Revenue From Ultimate Consumers (million dollars)	215,473	224,243	4.1
Residential	93,142	97,086	4.2
Commercial	70,492	73,704	4.6
Industrial	45,056	46,465	3.1
Other[17]	6,783	6,988	3.0
Average Revenue per Kilowatthour (cents)	6.66	6.78	1.8
Residential	8.16	8.21	.6
Commercial	7.26	7.36	1.4
Industrial	4.43	4.57	3.2
Other[17]	314,583	311,258	–1.1
Net Electric Plant Inc Fuel (million dollars)			
Major Investor Owned	70,594	75,679	7.2
Carbon Dioxide (CO2)	2,169,490	2,110,568	–2.7
Noncoincidental Summer Peak Load (megawatts)	1,271,011	1,790,181	40.8
DSM Actual Peak Load Reductions (megawatts)	26,455	22,901	–13.4
DSM Energy Savings (million kilowatthours)	50,563	1,565	9.9
DSM Cost (million dollars)	1,424	1,565	9.9

Table 1. Electric Power Industry Summary Statistics for the United States, 1999 and 2000 (Continued)

Item	1999 R	2000	Percent Change
Nonutility Power Producers[19]			
Generating Capability (megawatts)	146,603	208,348	42.1
Coal[20]	37,718	55,017	45.9
Petroleum Only[22]	3,845	10,128	163.4
Gas Only[21]	43,585	65,946	51.3
Dual Fired (gas and petroleum)	37,323	42,988	15.2
Nuclear	2,381	11,892	399.5
Hydroelectric Pumped Storage	620	1,502	142.3
Hydroelectric (conventional)	5,271	5,621	6.6
Other Renewable			
Geothermal	2,573	2,520	–2.1
Biomass[6]	9,883	9,519	–3.7
Wind	2,222	2,323	4.5
Solar Thermal	371	369	0.0
Photovoltaic	13	13	0.0
Other[23]	798	510	-36.1
Net Generation (million kilowatthours)	521,136	786,740	51.0
Coal[20]	113,415	269,648	137.8
Petroleum[22]	31,132	39,041	25.4
Gas[21]	274,140	322,084	17.5
Nuclear	3,218	48,460	1,405.9
Hydroelectric Pumped Storage	106	–579	–-
Hydroelectric (conventional)	19,508	22,418	14.9
Other Renewable			
Geothermal	13,129	13,942	6.2
Biomass[6]	57,621	58,669	1.8
Wind	4,465	5,565	24.6
Solar Thermal	0	0	.0
Photovoltaic	492	491	–-
Other[23]	3,910	7,003	79.1
Consumption[24]			
Coal (thousand short tons)	76,063	156,066	105.2
Petroleum (thousand barrels)[25]	85,016	93,474	9.9
Natural Gas (million cubic feet)	3,191,523	3,633,650	13.9
Other Gas (million cubic feet)[26]	1,473,207	1,666,166	13.1
Supply and Disposition (million kilowatthours)			
Gross Generation	544,561	828,325	52.1
Receipts[27]	90,395	95,158	5.3
Deliveries[28]	383,560	660,189	72.1
Facility Use	251,413	263,302	4.7

1 Electric utility and nonutility values (capability versus capacity, net versus gross generation, total emissions versus emission for the production of electricity) may not be summed directly--see Technical Notes for summation methodology.
2 Data are based on the initial commercial operation year for the generator.
3 In 1999, the useful utility thermal output produced additional emissions of 175 thousand short tons of sulfur dioxide, 64 thousand short tons of nitrogen oxides, and 18,647 thousand short tons of carbon dioxide. In 2000, the useful utility thermal output produced additional emissions of 137 thousand short tons of sulfur dioxide, 65 thousand short tons of nitrogen oxides, and 21,171 thousand short tons of carbon dioxide. In 1999, the useful nonutility thermal output produced additional emissions of 675 thousand short tons of sulfur dioxide, 539 thousand short tons of nitrogen oxides, and 127,000 thousand short tons of carbon dioxide. In 2000 the useful nonutility thermal output produced additional emissions of 663 thousand short tons of sulfur dioxide, 228 thousand short tons of nitrogen oxides, and 179,301 thousand short tons of carbon dioxide.
4 The report, ‘‘Carbon Dioxide Emissions from the Generation of Electric Power in the United States,’’ presented carbon dioxide emissions of 2,265,325 thousand short tons in 1999 and 2,361,535 thousand short tons in 2000. The nonutility data were revised since the release of that report.
5 Net summer capability based on primary energy source; waste gases, and waste steam are included in the original primary energy source (i.e., coal, petroleum, or gas)--historical data have been revised to reflect this change.
6 Includes wood, wood waste, peat, wood liquors, railroad ties, wood sludge, municipal solid waste, agricultural byproduct, straw, tires, landfill gases, fish oils.
7 Includes petroleum coke.
8 Represents total pumped storage facility production minus energy used for pumping. Negative generation denotes that electric power consumed for plant use exceeds gross generation.
9 For 1999 includes 211 megawatts multi-fueled capacity and 13 megawatts fueled by hot nitrogen; for 2000 includes 13 megawatts fueled by hot nitrogen.
10 Includes petroleum coke consumption of 1,608 thousand short tons in 1999 and 1,132 thousand short tons in 2000.
11 Does not include petroleum coke stocks of 355 thousand short tons at year end 1999 and 186 thousand short tons at year end 2000.
12 Does not include petroleum coke receipts of 2,906 thousand short tons in 1999 and 1,683 thousand short tons in 2000.
13 Includes small amounts of coke-oven, refinery, blast furnance gas, and landfill gas.
14 Average cost of fuel delivered to electric generating plants with a total steam-electric nameplate capacity of 50 or more megawatts; average cost values are weighted by Btu.
15 Does not include petroleum coke cost of 65.4 cents per million Btu in 1999 and 59.4 cents per million Btu in 2000.
16 All sales are bundled and therefore do not include power marketers (non-traditional energy service providers) relating to the restructuring of the electric power industry. For 1999 and 2000, these sales were 76.2 million megawatthours and 111.92 million (adjusted) megawatthours, respectively. For more detailed information regarding sales in restructed markets, see the Energy Information Administration’s publication, *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year.
17 Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
18 Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. See Technical Notes for emission factors used for calculation of carbon dioxide emission factors.
19 There is a discontinuity in capability estimates between 1999 and earlier years due to a change in reporting practices. In 1999 for the first time respondents self identified the facility’s primary energy source resulting in a reclassification compared to earlier years in some cases.

[20] Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, lignite waste, tar coal, and waste coal.
[21] Includes natural gas, waste heat, butane, propane, and other gas.
[22] Includes petroleum, petroleum coke, diesel, kerosene, light oil, liquid butane, liquid propane, oil waste, sludge oil, and tar oil.
[23] Includes batteries, chemicals, hydrogen, pitch, purchased steam, and sulfur.
[24] Includes consumption for useful thermal output. For 1999, included were 16 million short tons of coal, 22 million barrels of petroleum, and 752 billion cubic feet of gas. For 2000, included were 16 million short tons of coal, 21 million barrels of petroleum, and 749 billion cubic feet of gas.
[25] Includes petroleum coke consumption of 2,915 thousand short tons for 1999 and 3,537 thousand short tons for 2000.
[26] Includes butane, propane, and other gas,
[27] Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
[28] Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in these data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-860B is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures contribute to the disparity.

R = Revised data.

Notes: •Data for 2000 from Form EIA-767 are final pending approval from the Environmental Protection Agency. Other data in this table are final. •See Technical Notes for estimation methodology. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. •DSM = Demand-Side Management.

Sources: •Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities''; Form EIA-759, ''Monthly Power Plant Report''; Form EIA-767, ''Steam-Electric Plant Operation and Design Report''; Form EIA-860A, ''Annual Electric Generator Report - Utility''; Form EIA-860B, ''Annual Electric Generator Report - Nonutility''; Form EIA-861, ''Annual Electric Utility Report''; Federal Energy Regulatory Commission (FERC) Form 1, ''Annual Report of Major Electric Utilities, Licensees, and Others'' as edited by Navigant Knowledge Systems; Federal Energy Regulatory Commission (FERC) Form 423, ''Monthly Report of Cost and Quality of Fuels for Electric Plants.'' Form EIA-411, ''Coordinated Bulk Power Supply Programs''; Department of Energy, Office of Emergency Policy, Form OE-411, ''Coordinated Bulk Power Supply Program.''

Renewable Energy Resources

Section 171 of Public Law 102-486, the Energy Policy Act of 1992, requires the Administrator of the Energy Information Administration to annually collect and publish the results of a survey of electricity production from domestic renewable energy resources. This requirement includes reporting data on electricity production (in kilowatthours) and total installed capacity. The renewable energy resources shown in Table 1, "Electric Power Industry Summary Statistics for the United States, 1999 and 2000," will be reported in detail in the *Renewable Energy Annual, 2001*.

U.S. Electric Utility Retail Sales and Revenue

This chapter provides summary statistics on the sale of electricity to ultimate consumers, associated revenue, and average revenue per kilowatthour sold at the national, Census division, and State levels.

Background

Because electricity itself cannot be stored, it must be generated, transmitted to the consumer, and consumed instantaneously. Electric utility companies were formed to provide these services. An electric system consists of: generating plants (stations) to convert different energy sources to electric power; transformers to raise the voltage in order to reduce losses in transmitting the power; transmission lines to transmit the power to the general vicinity of consumption; transformers to lower the voltage; and distribution lines to distribute the power to the ultimate consumers. The entire system of generating stations, transformers, transmission lines, and distribution lines is a power system. Electric utilities historically build, design, and operate power systems. Most large investor-owned electric utilities own and operate entire power systems: the generation, transmission, and distribution functions. Many small companies are distribution companies, purchasing their electricity from generation suppliers, which can include traditional electric utilities, nonutility power producers, and power marketers. In anticipation of competition in the electric power industry, electric utility companies are forming separate business units for generation and customer service apart from transmission and distribution.

U.S. electric utilities are high-investment businesses and historically have been treated as monopolies because duplicate facilities, particularly transmission and distribution lines, would be inefficient. Thus, franchises are granted to electric utilities for given geographical areas by regulatory officials. To obtain a franchise, electric utilities must provide service to all consumers in their territories at a reasonable cost. As the electric power industry transitions to a competitive environment, access to tranmission and distribution lines will be opened; however, revenue associated with these facilities will remain regulated. The generation function is now competitive at the wholesale trade level, and some States are planning to initiate competition at the retail level.

The service territory of an electric utility generally has many different classifications of consumers. Electric utilities determine consumer classification by various factors such as demand, rate schedule, North American Industry Classification (NAICS) code, distribution voltage, accounting methods, end-use applications, and other social and economic characteristics. Electric utilities use consumer classifications for planning purposes (e.g. load growth and peak demands) and for deriving their rate schedules, often with the approval of a government regulatory agency.

End-Use Sectors

Consumers within the service territory of an electric utility are grouped into end-use sectors: residential, commercial, industrial, and other. The electric utility determines the criteria for end-use sector classification based on its service territory, size, location, ownership, and regulatory structure.

The residential sector includes private households and apartment buildings, where energy is consumed primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. The commercial sector includes nonmanufacturing business establishments, such as hotels, motels, restaurants, wholesale businesses, and retail stores, and health, social, and educational institutions. The industrial sector includes manufacturing, construction, mining, agriculture, fishing, and forestry establishments (NAICS codes 111 through 3399). Electric utilities may classify their commercial and industrial service based on demand or annual usage falling within a range specified by the utility, such as classifying a light manufacturer as commercial. The other sector includes public street and highway lighting, transportation, municipalities, divisions or agencies of State and Federal governments under special contracts or agreements, and other utility departments as defined by the pertinent regulatory agency and/or electric utility.

Revenue Requirements

The revenue requirements of an electric utility are set to reimburse the utility for providing electric service. Revenue requirements are the anticipated costs of providing services for some period of time in the future, usually one year. Revenue requirements are based on operating expenses, depreciation expenses, taxes, and return on the rate base (profit of the electric utility). The process of determining electricity prices generally follows three stages: (1) identification of revenue requirements, (2) allocation of the requirements for different classes of service (sectors), and (3) establishment of rate schedules for each sector. In the future, competition at the retail level may change the way rates are set and by whom. In a deregulated environment, generation prices will be market-based rather than cost-based as under the current regulated system. Rates will be “unbundled,” and bills will include a list of services and the associated rates and charges such as energy, transmission, distribution, metering, and other charges. Access will be opened to transmission and distribution lines, though the revenue associated with these lines will likely remain regulated. Under open access rules allowing competition for wholesale generation, some costs that are currently collected in rate schedules for generation assets may become stranded. This means that the costs of the generation asset may not be recoverable at market-based rates in a competitive environment for generation. The recovery of stranded costs is an issue that will need resolution as the industry undergoes deregulation. These stranded costs may be recovered in nonbypassable charges in the form of a rate per kilowatthour paid by all consumers in the jurisdictional distribution utility.

Currently, under a regulated environment, the rate schedules to generate revenue requirements for electric utilities, which are unique to each utility, are developed using a cost-based methodology and are subject to approval by the appropriate authority based on the ownership class applicable to the utility. For example, investor-owned electric utilities are regulated by State public service commissions and the Federal Energy Regulatory Commission (FERC). Under new FERC rules, transmission of wholesale power will remain regulated to ensure open access to transmission systems in a competitive environment, while wholesale rates for generation will become deregulated. State public utility commissions will continue to regulate retail sales and distribution. However, some States are considering retail competition for generation that will allow market-based rates for energy, while regulating distribution rates. Public electric utilities, in most States, are controlled through locally elected or appointed officials, and are not under the jurisdiction of FERC. Their rate schedules will, however, possibly be affected by any changes in State regulations addressing retail competition. A detailed discussion on utility classes of ownership and the emerging competitive environment are included in the "Industry Profile" section of the first chapter of this publication.

A rate schedule is a statement that the utility will provide service to a particular class of consumer at a certain price. Prices for different sectors vary based on the objectives of the utility. These objectives include the need to allocate the various costs incurred in providing service, to maintain the existing consumer base of the utility, and to promote new business.

Average Revenue per Kilowatthour

The average revenue per kilowatthour of electricity sold by electric utilities is calculated by dividing the annual revenue from retail sales by the annual retail sales for each sector and State. The resulting measurement is the cost (per kilowatthour of electricity sold) for providing service to a sector, given the rate schedule of the electric utility for that particular sector. The average revenue per kilowatthour is calculated for all consumers and for each sector (residential, commercial, industrial, and other sales). Utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of different consumers and the associated impacts on the cost to the electric utility for providing electrical service. The average revenue per kilowatthour by sector reported in this publication represents a weighted average of revenue and sales from ultimate consumers within that sector and across sectors for all consumers.

The electric revenue used to derive the average revenue per kilowatthour is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges.

Utility operating revenues cover, among other costs of service, State and Federal taxes assessed on the utility. State and local authorities tax the value of plants (property taxes), the amount of revenues (gross receipts taxes), purchases of materials and services (sales and use taxes), and a potentially long list of other items that vary extensively by taxing authority. The Federal component of these taxes are, for the most part, “payroll” taxes. Taxes deducted from employees' pay such as Federal income taxes and employees' share of social security taxes are not a part of the utility's “tax costs,” but are paid to the taxing authorities in the name of the employees. These taxes are included in the utility's cost of service (i.e., revenue requirements) and in the amounts recovered from consumers in rates. Therefore, such taxes are reported as operating revenues.

Electric utilities, like many other business enterprises, are required by various taxing authorities to collect and remit taxes assessed on its consumers. In this regard, the utility serves as an agent for the taxing authority. Taxes assessed on the consumer but collected by the utility, such as gross receipts tax, sales tax, or environmental surcharges, are called “pass-through” taxes. These taxes do not represent a cost of the utility and are not recorded in the operating revenues of the utility. However, taxing authorities differ in whether a specific tax is assessed on the utility or the consumer, a difference that in turn determines whether or not the tax is included in the electric utility's operating revenue.

Average revenue per kilowatthour for the residential sector is generally higher than for other sectors. This is primarily due to the higher costs associated with serving many consumers who use relatively small amounts of electricity. These costs include direct-load costs (such as those for distribution lines, transformers, and meters) in addition to consumer or administrative costs. The industrial sector generally has the lowest average revenue per kilowatthour because of the economies of serving a few consumers who use relatively large amounts of electricity.

Federal electric utilities generally have the lowest average revenue per kilowatthour among the ownership classes because they have access to relatively low-cost financing and mostly utilize inexpensive hydroelectric facilities. Because publicly owned electric utilities also have access to relatively low-cost financing and are nonprofit entities, they have lower average revenue per kilowatthour than investor-owned electric utilities. Although cooperative electric utilities have economic advantages similar to those of publicly owned electric utilities, cooperatives generally serve sparsely populated areas; as a consequence, cooperatives generally have higher average revenue per kilowatthour than publicly owned utilities.

Because of the type and availability of capacity and the cost of fuel, the average revenue per kilowatthour differs across U.S. Census divisions. The New England and Middle Atlantic Census Divisions tend to have an average revenue per kilowatthour that is higher than the national average because of their reliance on petroleum; whereas, the East and West South Central Census Divisions rely on gas-fired generation and the East North Central and South Atlantic Census Divisions rely on coal-fired generation. Petroleum is generally a more expensive energy source than coal and natural gas. Because the Mountain Census Division relies on inexpensive hydroelectric generation, the average revenue per kilowatthour in this region is usually below the national average for all classes of consumers. The Census divisions where Federal hydroelectric facilities provide significant amounts of electricity, such as the East South Central Census Division, also have low average revenue per kilowatthour.

Source of Data

Summary statistics on retail sales of electricity by electric utilities and average revenue are provided in the following tables. These data were obtained from the Form EIA-861, "Annual Electric Utility Report." The form is an annual census of electric utilities (approximately 3,300) that own and/or operate facilities within the United States, its territories, and Puerto Rico.[7] Data collected include the generation, transmission, distribution, sales, and associated revenue of electric energy and is primarily used by the public. More detailed statistics on sales, average revenue, and revenue per kilowatthour are published annually in the *Electric Sales and Revenue*[8] Some tables contain bundled (energy and delivery services) and unbundled data, while others contain only bundled data.

[7] Summary data in this publication are for the United States only and do not include Puerto Rico and the U.S. territories.

[8] For detailed data, including data for the power authorities of Guam, Puerto Rico, American Samoa, and the Virgin Islands, see the *Electric Sales and Revenue*, DOE/EIA-0540, published annually by the Energy Information Administration.

Table 2a. U.S. Average Monthly Bill By Sector, Census Division and State, 2000

RESIDENTIAL

Census Division State	Number of Consumers	Average Monthly Consumption (kWh)	Average Revenue (cents per kilowatthour)	Average Monthly Bill (dollars and cents)
New England	**5,780,963**	**595**	**11.17**	**66.50**
Connecticut	1,364,268	711	10.86	77.24
Maine	650,326	479	12.49	59.79
Massachusetts	2,526,707	579	10.53	61.01
New Hampshire	542,422	562	13.15	73.87
Rhode Island	413,746	537	11.28	60.53
Vermont	283,494	599	12.30	73.64
Middle Atlantic	**14,828,060**	**633**	**11.39**	**72.06**
New Jersey	3,185,052	642	10.27	65.98
New York	6,710,008	534	13.97	74.64
Pennsylvania	4,933,000	760	9.53	72.49
East North Central	**18,406,935**	**751**	**8.22**	**61.73**
Illinois	4,748,863	704	8.83	62.23
Indiana	2,545,743	938	6.87	64.38
Michigan	4,099,153	624	8.52	53.22
Ohio	4,684,127	827	8.61	71.20
Wisconsin	2,329,049	713	7.53	53.73
West North Central	**8,206,367**	**893**	**7.35**	**65.67**
Iowa	1,243,488	806	8.37	67.50
Kansas	1,136,079	919	7.65	70.33
Minnesota	2,051,355	757	7.52	56.88
Missouri	2,440,099	1,010	7.04	71.17
Nebraska	724,701	960	6.53	62.63
North Dakota	288,470	979	6.44	63.02
South Dakota	322,175	885	7.42	65.69
South Atlantic	**21,987,335**	**1,106**	**7.70**	**85.21**
Delaware	335,282	889	8.54	75.87
District of Columbia	198,264	683	8.03	54.80
Florida	7,169,802	1,151	7.77	89.45
Georgia	3,385,235	1,097	7.60	83.36
Maryland	1,986,198	1,005	7.95	79.92
North Carolina	3,561,203	1,089	7.97	86.79
South Carolina	1,764,298	1,194	7.58	90.51
Virginia	2,767,245	1,131	7.52	85.00
West Virginia	819,808	990	6.27	62.01
East South Central	**7,251,279**	**1,218**	**6.43**	**78.31**
Alabama	1,930,037	1,242	7.05	87.55
Kentucky	1,765,011	1,104	5.47	60.37
Mississippi	1,172,984	1,221	6.93	84.65
Tennessee	2,383,247	1,281	6.33	81.00
West South Central	**12,534,464**	**1,191**	**7.77**	**92.55**
Arkansas	1,177,901	1,052	7.45	78.42
Louisiana	1,818,627	1,270	7.67	97.47
Oklahoma	1,514,670	1,081	7.03	75.91
Texas	8,023,266	1,214	7.96	96.64
Mountain	**7,167,986**	**846**	**7.42**	**62.73**
Arizona	1,959,669	1,056	8.44	89.13
Colorado	1,771,294	660	7.31	48.21
Idaho	531,075	1,099	5.39	59.23
Montana	401,982	810	6.49	52.57
Nevada	794,493	987	7.28	71.83
New Mexico	728,046	565	8.36	47.24
Utah	759,649	715	6.29	44.94
Wyoming	221,778	790	6.50	51.32
Pacific Contiguous	**14,955,427**	**727**	**8.73**	**63.49**
California	11,091,616	595	10.89	64.83
Oregon	1,434,298	1,058	5.88	62.22
Washington	2,429,513	1,133	5.13	58.14
Pacific Noncontiguous	**598,895**	**643**	**14.42**	**92.69**
Alaska	230,534	671	11.45	76.81
Hawaii	368,361	625	16.41	102.63
U.S. Total	**111,717,711**	**889**	**8.24**	**73.26**

See footnotes at end of table.

Table 2a. U.S. Average Monthly Bill By Sector, Census Division and State, 2000 (Continued)

COMMERCIAL

Census Division State	Number of Consumers	Average Monthly Consumption (kWh)	Average Revenue (cents per kilowatthour)	Average Monthly Bill (dollars and cents)
New England	**733,175**	**5,402**	**9.47**	**511.31**
Connecticut	130,771	7,604	9.27	704.82
Maine	102,433	3,020	10.23	308.84
Massachusetts	324,098	5,922	9.13	540.42
New Hampshire	85,083	3,697	10.81	399.46
Rhode Island	49,665	5,312	9.50	504.63
Vermont	41,125	3,869	10.61	410.43
Middle Atlantic	**1,965,356**	**5,719**	**10.25**	**586.31**
New Jersey	432,580	6,379	9.14	583.18
New York	881,118	5,652	12.65	715.23
Pennsylvania	651,658	5,371	7.71	414.09
East North Central	**2,051,579**	**6,469**	**7.20**	**465.48**
Illinois	493,670	7,403	7.31	541.28
Indiana	290,737	5,867	5.93	348.02
Michigan	461,175	6,481	7.90	511.82
Ohio	527,626	6,437	7.61	489.99
Wisconsin	278,371	5,485	6.03	330.50
West North Central	**1,110,162**	**5,281**	**6.07**	**320.80**
Iowa	171,611	4,067	6.57	267.39
Kansas	186,755	5,583	6.25	348.86
Minnesota	217,384	4,439	6.36	282.13
Missouri	316,761	6,807	5.83	396.65
Nebraska	120,387	4,874	5.42	264.08
North Dakota	46,643	4,563	6.08	277.40
South Dakota	50,621	3,987	6.64	264.80
South Atlantic	**2,791,219**	**7,067**	**6.29**	**444.65**
Delaware	40,616	8,309	5.89	489.42
District of Columbia	27,224	25,503	7.55	1,926.07
Florida	882,205	6,813	6.25	426.09
Georgia	410,782	7,496	6.50	487.16
Maryland	218,342	9,849	6.55	645.28
North Carolina	513,727	5,979	6.36	380.32
South Carolina	274,003	5,317	6.35	337.49
Virginia	306,821	7,686	5.65	434.00
West Virginia	117,499	4,820	5.46	262.97
East South Central	**1,105,854**	**5,290**	**6.16**	**325.64**
Alabama	313,017	5,073	6.58	333.83
Kentucky	232,298	4,998	5.14	257.05
Mississippi	184,783	5,164	6.41	330.87
Tennessee	375,756	5,712	6.28	358.63
West South Central	**1,657,538**	**6,281**	**6.78**	**425.71**
Arkansas	143,544	5,078	5.93	301.15
Louisiana	218,500	6,951	7.18	498.83
Oklahoma	202,080	5,408	6.14	332.16
Texas	1,093,414	6,467	6.88	444.75
Mountain	**982,885**	**6,284**	**6.14**	**385.97**
Arizona	211,921	8,419	7.34	618.32
Colorado	244,080	6,142	5.55	340.78
Idaho	92,417	6,373	4.24	270.08
Montana	75,861	4,165	5.60	233.44
Nevada	112,192	4,864	6.74	327.84
New Mexico	113,364	4,906	7.06	346.21
Utah	84,998	7,730	5.23	404.11
Wyoming	48,052	4,766	5.29	251.90
Pacific Contiguous	**1,859,443**	**5,915**	**8.67**	**512.81**
California	1,371,137	5,634	10.25	577.53
Oregon	208,840	6,101	5.06	308.74
Washington	279,466	7,154	4.86	347.80
Pacific Noncontiguous	**91,856**	**4,783**	**12.68**	**606.27**
Alaska	38,074	4,895	9.77	478.39
Hawaii	53,782	4,704	14.81	696.81
U.S. Total	**14,349,067**	**6,128**	**7.43**	**455.35**

See footnotes at end of table.

Table 2a. U.S. Average Monthly Bill By Sector, Census Division and State, 2000 (Continued)

INDUSTRIAL

Census Division State	Number of Consumers	Average Monthly Consumption (kWh)	Average Revenue (cents per kilowatthour)	Average Monthly Bill (dollars and cents)
New England	**28,000**	**78,961**	**7.85**	**6,198.68**
Connecticut	5,864	82,576	7.32	6,040.56
Maine	1,966	192,884	6.89	13,290.61
Massachusetts	13,983	62,773	8.20	5,146.17
New Hampshire	3,307	65,452	9.17	6,000.38
Rhode Island	2,492	46,600	8.76	4,084.00
Vermont	388	353,492	7.31	25,856.74
Middle Atlantic	**56,361**	**122,866**	**5.97**	**7,334.76**
New Jersey	12,463	78,978	8.58	6,774.18
New York	8,718	246,982	5.37	13,273.27
Pennsylvania	35,180	107,657	5.63	6,061.73
East North Central	**72,976**	**258,565**	**4.44**	**11,493.08**
Illinois	5,009	681,094	4.99	33,985.58
Indiana	19,058	210,062	3.81	7,998.29
Michigan	13,670	227,187	5.09	11,572.00
Ohio	29,631	208,170	4.37	9,103.32
Wisconsin	5,608	388,758	4.04	15,714.04
West North Central	**51,374**	**137,198**	**4.30**	**5,896.16**
Iowa	4,050	352,403	3.89	13,692.24
Kansas	14,391	59,193	4.55	2,692.69
Minnesota	10,838	221,767	4.57	10,142.78
Missouri	9,541	140,445	4.43	6,218.84
Nebraska	8,974	67,566	3.61	2,440.72
North Dakota	1,860	135,811	3.98	5,399.96
South Dakota	1,720	97,031	4.49	4,358.72
South Atlantic	**78,561**	**178,386**	**4.16**	**7,419.00**
Delaware	553	542,626	3.73	20,229.81
District of Columbia	1	22,713,167	4.74	1,076,666.67
Florida	26,024	60,469	4.84	2,925.06
Georgia	10,343	290,739	4.10	11,932.39
Maryland	7,382	113,636	4.14	4,704.00
North Carolina	12,577	226,948	4.58	10,397.80
South Carolina	5,077	546,706	3.74	20,452.60
Virginia	5,371	319,912	3.90	12,467.56
West Virginia	11,233	82,220	3.76	3,092.92
East South Central	**20,255**	**497,281**	**3.70**	**18,387.97**
Alabama	6,252	466,977	3.87	18,091.48
Kentucky	7,724	406,625	3.01	12,253.99
Mississippi	4,500	293,637	4.14	12,161.44
Tennessee	1,779	1,512,510	4.09	61,812.30
West South Central	**117,739**	**116,601**	**4.48**	**5,227.46**
Arkansas	25,597	56,218	4.20	2,362.69
Louisiana	15,491	171,876	5.00	8,602.39
Oklahoma	15,371	75,548	4.09	3,089.29
Texas	61,280	138,148	4.42	6,107.25
Mountain	**30,792**	**186,398**	**4.22**	**7,862.83**
Arizona	4,760	209,649	5.27	11,055.22
Colorado	3,566	232,632	4.25	9,895.73
Idaho	6,126	114,372	3.11	3,559.46
Montana	1,362	401,856	3.97	15,942.67
Nevada	1,462	640,609	4.98	31,917.86
New Mexico	1,493	306,563	4.69	14,365.82
Utah	8,441	78,164	3.35	2,618.08
Wyoming	3,582	170,309	3.36	5,714.89
Pacific Contiguous	**68,981**	**140,225**	**5.47**	**7,665.63**
California	42,222	126,930	7.14	9,067.08
Oregon	11,896	114,558	3.56	4,075.96
Washington	14,863	198,535	3.30	6,557.55
Pacific Noncontiguous	**1,515**	**267,904**	**10.81**	**28,960.40**
Alaska	854	101,154	7.56	7,652.03
Hawaii	661	483,343	11.69	56,490.42
U.S. Total	**526,554**	**168,428**	**4.64**	**7,813.30**

Notes: •Data are final. Commercial or industrial billings are generally determined by the level of demand and consumption of electricity rather than by consumer economic activity. Average monthly usage in kilowatthours is calculated by dividing the megawatthours by 12(months), dividing the results by the number of consumers, and multiplying by 1000 (to convert to kilowatthours). The average revenue is calculated by dividing the revenue by the megawatthours, then multiplying by 100 (to convert to cents). The average monthly bill is calculated by dividing the revenue by 12(months), dividing the result by the number of consumers, and multiplying by 1000 (to convert to dollars and cents).

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report'', and calculated from the data shown in Tables 14, 15, 16, and Appendix C. of the *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year.

Table 2b. Number of Customers (Bundled and Unbundled) by Sector, Census Division, and State, 2000

Census Division State	Residential	Commercial	Industrial	Other[1]	All Sectors
New England	**5,780,963**	**733,175**	**28,000**	**41,298**	**6,583,436**
Connecticut	1,364,268	130,771	5,864	5,008	1,505,911
Maine	650,326	102,433	1,966	15,892	770,617
Massachusetts	2,526,707	324,098	13,983	12,368	2,877,156
New Hampshire	542,422	85,083	3,307	5,449	636,261
Rhode Island	413,746	49,665	2,492	1,150	467,053
Vermont	283,494	41,125	388	1,431	326,438
Middle Atlantic	**14,828,060**	**1,965,356**	**56,361**	**52,946**	**16,902,723**
New Jersey	3,185,052	432,580	12,463	10,427	3,640,522
New York	6,710,008	881,118	8,718	34,812	7,634,656
Pennsylvania	4,933,000	651,658	35,180	7,707	5,627,545
East North Central	**18,406,935**	**2,051,579**	**72,976**	**88,229**	**20,619,719**
Illinois	4,748,863	493,670	5,009	34,859	5,282,401
Indiana	2,545,743	290,737	19,058	9,805	2,865,343
Michigan	4,099,153	461,175	13,670	9,856	4,583,854
Ohio	4,684,127	527,626	29,631	20,242	5,261,626
Wisconsin	2,329,049	278,371	5,608	13,467	2,626,495
West North Central	**8,206,367**	**1,110,162**	**51,374**	**131,498**	**9,499,401**
Iowa	1,243,488	171,611	4,050	17,706	1,436,855
Kansas	1,136,079	186,755	14,391	15,591	1,352,816
Minnesota	2,051,355	217,384	10,838	24,128	2,303,705
Missouri	2,440,099	316,761	9,541	14,109	2,780,510
Nebraska	724,701	120,387	8,974	44,700	898,762
North Dakota	288,470	46,643	1,860	6,235	343,208
South Dakota	322,175	50,621	1,720	9,029	383,545
South Atlantic	**21,987,335**	**2,791,219**	**78,561**	**190,695**	**25,047,810**
Delaware	335,282	40,616	553	768	377,219
District of Columbia	198,264	27,224	1	33	225,522
Florida	7,169,802	882,205	26,024	74,815	8,152,846
Georgia	3,385,235	410,782	10,343	32,284	3,838,644
Maryland	1,986,198	218,342	7,382	1,911	2,213,833
North Carolina	3,561,203	513,727	12,577	18,204	4,105,711
South Carolina	1,764,298	274,003	5,077	16,118	2,059,496
Virginia	2,767,245	306,821	5,371	43,472	3,122,909
West Virginia	819,808	117,499	11,233	3,090	951,630
East South Central	**7,251,279**	**1,105,854**	**20,255**	**58,539**	**8,435,927**
Alabama	1,930,037	313,017	6,252	13,447	2,262,753
Kentucky	1,765,011	232,298	7,724	23,040	2,028,073
Mississippi	1,172,984	184,783	4,500	9,699	1,371,966
Tennessee	2,383,247	375,756	1,779	12,353	2,773,135
West South Central	**12,534,464**	**1,657,538**	**117,739**	**176,331**	**14,486,072**
Arkansas	1,177,901	143,544	25,597	15,796	1,362,838
Louisiana	1,818,627	218,500	15,491	22,545	2,075,163
Oklahoma	1,514,670	202,080	15,371	16,121	1,748,242
Texas	8,023,266	1,093,414	61,280	121,869	9,299,829
Mountain	**7,167,986**	**982,885**	**30,792**	**153,974**	**8,335,637**
Arizona	1,959,669	211,921	4,760	17,212	2,193,562
Colorado	1,771,294	244,080	3,566	97,937	2,116,877
Idaho	531,075	92,417	6,126	3,367	632,985
Montana	401,982	75,861	1,362	14,793	493,998
Nevada	794,493	112,192	1,462	1,781	909,928
New Mexico	728,046	113,364	1,493	10,868	853,771
Utah	759,649	84,998	8,441	4,889	857,977
Wyoming	221,778	48,052	3,582	3,127	276,539
Pacific Contiguous	**14,955,427**	**1,859,443**	**68,981**	**72,303**	**16,956,154**
California	11,091,616	1,371,137	42,222	32,856	12,537,831
Oregon	1,434,298	208,840	11,896	11,001	1,666,035
Washington	2,429,513	279,466	14,863	28,446	2,752,288
Pacific Noncontiguous	**598,895**	**91,856**	**1,515**	**8,372**	**700,638**
Alaska	230,534	38,074	854	4,068	273,530
Hawaii	368,361	53,782	661	4,304	427,108
U.S. Total	**111,717,711**	**14,349,067**	**526,554**	**974,185**	**127,567,517**

[1] Includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. Data include both bundled and unbundled consumers. Data for unbundled consumers are from ''Electric Sales and Revenue 2000,'' Appendix C and are adjusted (see Appendix C for discussion).

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report'', and calculated from the data shown in Tables 14, 15, 16, and Appendix C. of the *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year.

Table 2c. Sales to Bundled and Unbundled Consumers by Sector, Census Division, and State, 2000
(Million Kilowatthours)

Census Division State	Residential	Commercial	Industrial	Other[1]	All Sectors
New England	**41,302**	**47,527**	**26,531**	**1,627**	**116,987**
Connecticut	11,645	11,932	5,811	564	29,952
Maine	3,737	3,712	4,551	163	12,163
Massachusetts	17,562	23,033	10,533	644	51,773
New Hampshire	3,656	3,774	2,597	131	10,159
Rhode Island	2,664	3,166	1,394	78	7,301
Vermont	2,037	1,910	1,646	46	5,639
Middle Atlantic	**112,573**	**134,879**	**83,098**	**15,299**	**345,849**
New Jersey	24,547	33,112	11,812	506	69,977
New York	43,018	59,764	25,838	13,407	142,027
Pennsylvania	45,008	42,002	45,449	1,387	133,845
East North Central	**165,920**	**159,269**	**226,428**	**15,969**	**567,585**
Illinois	40,146	43,855	40,939	9,756	134,697
Indiana	28,649	20,468	48,040	618	97,775
Michigan	30,707	35,867	37,268	930	104,772
Ohio	46,488	40,757	74,019	3,930	165,195
Wisconsin	19,929	18,321	26,162	734	65,146
West North Central	**87,927**	**70,358**	**84,581**	**6,613**	**249,479**
Iowa	12,029	8,375	17,127	1,558	39,088
Kansas	12,528	12,511	10,222	660	35,921
Minnesota	18,629	11,580	28,842	730	59,782
Missouri	29,581	25,875	16,080	1,106	72,643
Nebraska	8,346	7,041	7,276	1,686	24,349
North Dakota	3,390	2,554	3,031	438	9,413
South Dakota	3,423	2,422	2,003	435	8,283
South Atlantic	**291,800**	**236,704**	**168,170**	**22,198**	**718,871**
Delaware	3,575	4,050	3,601	49	11,274
District of Columbia	1,624	8,332	273	387	10,616
Florida	99,006	72,130	18,884	5,824	195,843
Georgia	44,560	36,951	36,085	1,589	119,185
Maryland	23,949	25,804	10,066	858	60,678
North Carolina	46,537	36,859	34,252	2,208	119,855
South Carolina	25,270	17,483	33,308	951	77,012
Virginia	37,541	28,299	20,619	10,256	96,715
West Virginia	9,738	6,796	11,083	76	27,693
East South Central	**105,946**	**70,197**	**120,869**	**5,893**	**302,904**
Alabama	28,756	19,057	35,034	677	83,524
Kentucky	23,374	13,933	37,689	3,320	78,316
Mississippi	17,193	11,451	15,856	836	45,336
Tennessee	36,622	25,757	32,289	1,060	95,728
West South Central	**179,125**	**124,935**	**164,742**	**21,326**	**490,128**
Arkansas	14,871	8,746	17,268	726	41,611
Louisiana	27,719	18,225	31,950	2,795	80,690
Oklahoma	19,640	13,115	13,935	2,874	49,564
Texas	116,895	84,848	101,588	14,931	318,263
Mountain	**72,747**	**74,114**	**68,875**	**7,975**	**223,710**
Arizona	24,844	21,411	11,975	2,900	61,130
Colorado	14,029	17,989	9,955	1,047	43,020
Idaho	7,006	7,068	8,408	352	22,834
Montana	3,908	3,792	6,568	312	14,580
Nevada	9,406	6,548	11,239	598	27,792
New Mexico	4,937	6,674	5,492	1,698	18,801
Utah	6,514	7,884	7,917	870	23,185
Wyoming	2,103	2,748	7,321	196	12,368
Pacific Contiguous	**130,488**	**131,978**	**116,074**	**12,359**	**390,899**
California	79,241	92,697	64,311	7,808	244,057
Oregon	18,212	15,289	16,353	476	50,330
Washington	33,036	23,991	35,410	4,075	96,511
Pacific Noncontiguous	**4,620**	**5,272**	**4,870**	**238**	**15,001**
Alaska	1,855	2,236	1,037	182	5,310
Hawaii	2,765	3,036	3,834	56	9,691
U.S. Total	**1,192,446**	**1,055,232**	**1,064,239**	**109,496**	**3,421,414**

1 Includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. Data include both bundled and unbundled consumers. Data for unbundled consumers are from ''Electric Sales and Revenue 2000,'' Appendix C and are adjusted (see Appendix C for discussion).

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report'', and calculated from the data shown in Tables 14, 15, 16, and Appendix C. of the *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year.

Table 2d. Revenues for Sales to Bundled and Unbundled Consumers (Including Delivery Service Revenue) by Sector, Census Division, and State, 2000
(Thousand Dollars)

Census Division State	Residential	Commercial	Industrial	Other[1]	All Sectors
New England	**4,612,877**	**4,498,598**	**2,082,756**	**215,672**	**11,409,903**
Connecticut	1,264,461	1,106,042	425,062	56,729	2,852,294
Maine	466,584	379,625	313,552	18,716	1,178,477
Massachusetts	1,849,974	2,101,790	863,506	98,742	4,914,012
New Hampshire	480,832	407,847	238,119	16,253	1,143,051
Rhode Island	300,523	300,747	122,128	19,584	742,982
Vermont	250,503	202,547	120,389	5,648	579,087
Middle Atlantic	**12,822,653**	**13,827,762**	**4,960,734**	**1,415,619**	**33,026,768**
New Jersey	2,521,947	3,027,248	1,013,120	61,271	6,623,586
New York	6,009,788	7,562,390	1,388,596	1,205,845	16,166,619
Pennsylvania	4,290,918	3,238,124	2,559,018	148,503	10,236,563
East North Central	**13,634,548**	**11,459,636**	**10,064,631**	**1,001,724**	**36,160,539**
Illinois	3,546,278	3,206,541	2,042,805	549,396	9,345,020
Indiana	1,966,764	1,214,196	1,829,176	57,905	5,068,041
Michigan	2,617,706	2,832,471	1,898,271	100,192	7,448,640
Ohio	4,002,196	3,102,406	3,236,887	239,899	10,581,388
Wisconsin	1,501,604	1,104,022	1,057,492	54,332	3,717,450
West North Central	**6,466,716**	**4,273,746**	**3,634,912**	**405,673**	**14,781,047**
Iowa	1,007,251	550,635	665,443	95,499	2,318,828
Kansas	958,759	781,826	465,006	48,134	2,253,725
Minnesota	1,400,071	735,968	1,319,129	55,511	3,510,679
Missouri	2,083,889	1,507,701	712,007	66,649	4,370,246
Nebraska	544,639	381,501	262,836	102,826	1,291,802
North Dakota	218,161	155,264	120,527	18,347	512,299
South Dakota	253,946	160,851	89,964	18,707	523,468
South Atlantic	**22,481,208**	**14,893,541**	**6,994,128**	**1,378,694**	**45,747,571**
Delaware	305,253	238,539	134,245	6,942	684,979
District of Columbia	130,381	629,224	12,920	25,820	798,345
Florida	7,696,330	4,510,745	913,461	405,365	13,525,901
Georgia	3,386,290	2,401,378	1,481,000	135,268	7,403,936
Maryland	1,904,954	1,690,690	416,699	76,283	4,088,626
North Carolina	3,709,073	2,344,590	1,569,277	144,131	7,767,071
South Carolina	1,916,222	1,109,685	1,246,054	59,804	4,331,765
Virginia	2,822,623	1,597,907	803,559	517,579	5,741,668
West Virginia	610,082	370,783	416,913	7,502	1,405,280
East South Central	**6,814,409**	**4,321,270**	**4,469,380**	**356,992**	**15,962,051**
Alabama	2,027,802	1,253,946	1,357,295	48,214	4,687,257
Kentucky	1,278,670	716,536	1,135,798	145,951	3,276,955
Mississippi	1,191,491	733,680	656,718	69,678	2,651,567
Tennessee	2,316,446	1,617,108	1,319,569	93,149	5,346,272
West South Central	**13,920,167**	**8,467,630**	**7,385,705**	**1,409,253**	**31,182,755**
Arkansas	1,108,516	518,744	725,734	46,371	2,399,365
Louisiana	2,127,079	1,307,937	1,599,115	195,101	5,229,232
Oklahoma	1,379,786	805,464	569,825	156,832	2,911,907
Texas	9,304,786	5,835,485	4,491,031	1,010,949	20,642,251
Mountain	**5,395,762**	**4,552,338**	**2,905,347**	**399,047**	**13,252,494**
Arizona	2,096,080	1,572,411	631,474	131,243	4,431,208
Colorado	1,024,815	998,121	423,458	81,384	2,527,778
Idaho	377,498	299,515	261,663	14,526	953,202
Montana	253,610	212,509	260,567	2,127	728,813
Nevada	684,851	441,376	559,967	28,515	1,714,709
New Mexico	412,707	470,967	257,378	95,679	1,236,731
Utah	409,622	412,187	265,191	36,003	1,123,003
Wyoming	136,579	145,252	245,649	9,570	537,050
Pacific Contiguous	**11,394,924**	**11,442,527**	**6,345,396**	**562,424**	**29,745,271**
California	8,628,982	9,502,420	4,593,965	379,945	23,105,312
Oregon	1,070,881	773,729	581,852	33,769	2,460,231
Washington	1,695,061	1,166,378	1,169,579	148,710	4,179,728
Pacific Noncontiguous	**666,123**	**668,279**	**526,500**	**34,099**	**1,895,001**
Alaska	212,474	218,572	78,418	25,782	535,246
Hawaii	453,649	449,707	448,082	8,317	1,359,755
U.S. Total	**98,209,387**	**78,405,327**	**49,369,489**	**7,179,197**	**233,163,400**

[1] Includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. Data include both bundled and unbundled consumers. Data for unbundled consumers are from ''Electric Sales and Revenue 2000,'' Appendix C and are adjusted (see Appendix C for discussion).

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report'', and calculated from the data shown in Tables 14, 15, 16, and Appendix C. of the *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year.

Table 2e. Average Revenue per Kilowatthour for Bundled and Unbundled Consumers by Sector, Census Division, and State, 2000

(Cents)

Census Division State	Residential	Commercial	Industrial	Other[1]	All Sectors
New England	**11.17**	**9.47**	**7.85**	**13.26**	**9.75**
Connecticut	10.86	9.27	7.32	10.06	9.52
Maine	12.49	10.23	6.89	11.45	9.69
Massachusetts	10.53	9.13	8.20	15.32	9.49
New Hampshire	13.15	10.81	9.17	12.41	11.25
Rhode Island	11.28	9.50	8.76	25.19	10.18
Vermont	12.30	10.61	7.31	12.20	10.27
Middle Atlantic	**11.39**	**10.25**	**5.97**	**9.25**	**9.55**
New Jersey	10.27	9.14	8.58	12.11	9.47
New York	13.97	12.65	5.37	8.99	11.38
Pennsylvania	9.53	7.71	5.63	10.71	7.65
East North Central	**8.22**	**7.20**	**4.44**	**6.27**	**6.37**
Illinois	8.83	7.31	4.99	5.63	6.94
Indiana	6.87	5.93	3.81	9.37	5.18
Michigan	8.52	7.90	5.09	10.77	7.11
Ohio	8.61	7.61	4.37	6.10	6.41
Wisconsin	7.53	6.03	4.04	7.40	5.71
West North Central	**7.35**	**6.07**	**4.30**	**6.13**	**5.92**
Iowa	8.37	6.57	3.89	6.13	5.93
Kansas	7.65	6.25	4.55	7.29	6.27
Minnesota	7.52	6.36	4.57	7.60	5.87
Missouri	7.04	5.83	4.43	6.02	6.02
Nebraska	6.53	5.42	3.61	6.10	5.31
North Dakota	6.44	6.08	3.98	4.19	5.44
South Dakota	7.42	6.64	4.49	4.30	6.32
South Atlantic	**7.70**	**6.29**	**4.16**	**6.21**	**6.36**
Delaware	8.54	5.89	3.73	14.19	6.08
District of Columbia	8.03	7.55	4.74	6.67	7.52
Florida	7.77	6.25	4.84	6.96	6.91
Georgia	7.60	6.50	4.10	8.51	6.21
Maryland	7.95	6.55	4.14	8.89	6.74
North Carolina	7.97	6.36	4.58	6.53	6.48
South Carolina	7.58	6.35	3.74	6.29	5.62
Virginia	7.52	5.65	3.90	5.05	5.94
West Virginia	6.27	5.46	3.76	9.88	5.07
East South Central	**6.43**	**6.16**	**3.70**	**6.06**	**5.27**
Alabama	7.05	6.58	3.87	7.12	5.61
Kentucky	5.47	5.14	3.01	4.40	4.18
Mississippi	6.93	6.41	4.14	8.33	5.85
Tennessee	6.33	6.28	4.09	8.79	5.58
West South Central	**7.77**	**6.78**	**4.48**	**6.61**	**6.36**
Arkansas	7.45	5.93	4.20	6.39	5.77
Louisiana	7.67	7.18	5.00	6.98	6.48
Oklahoma	7.03	6.14	4.09	5.46	5.88
Texas	7.96	6.88	4.42	6.77	6.49
Mountain	**7.42**	**6.14**	**4.22**	**5.00**	**5.92**
Arizona	8.44	7.34	5.27	4.53	7.25
Colorado	7.31	5.55	4.25	7.77	5.88
Idaho	5.39	4.24	3.11	4.13	4.17
Montana	6.49	5.60	3.97	.68	5.00
Nevada	7.28	6.74	4.98	4.77	6.17
New Mexico	8.36	7.06	4.69	5.64	6.58
Utah	6.29	5.23	3.35	4.14	4.84
Wyoming	6.50	5.29	3.36	4.87	4.34
Pacific Contiguous	**8.73**	**8.67**	**5.47**	**4.55**	**7.61**
California	10.89	10.25	7.14	4.87	9.47
Oregon	5.88	5.06	3.56	7.10	4.89
Washington	5.13	4.86	3.30	3.65	4.33
Pacific Noncontiguous	**14.42**	**12.68**	**10.81**	**14.31**	**12.63**
Alaska	11.45	9.77	7.56	14.17	10.08
Hawaii	16.41	14.81	11.69	14.76	14.03
U.S. Total	**8.24**	**7.43**	**4.64**	**6.56**	**6.81**

1 Includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. Data include both bundled and unbundled consumers. Data for unbundled consumers are from ''Electric Sales and Revenue 2000,'' Appendix C and are adjusted (see Appendix C for discussion).

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report'', and calculated from the data shown in Tables 14, 15, 16, and Appendix C. of the *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year.

Table 3a. U.S. Electric Utility Sales to Bundled Ultimate Consumers and Associated Revenue by Sector, 1996 Through 2000

Item	1996	1997	1998	1999	2000
Sales (million kilowatthours)					
Residential	1,082,491	1,075,767	1,127,735	1,140,761	1,183,137
Commercial	887,425	928,440	968,528	970,601	1,000,865
Industrial	1,030,356	1,032,653	1,040,038	1,017,783	1,017,723
Other[1]	97,539	102,901	103,518	106,754	107,824
U.S. Total	**3,097,810**	**3,139,761**	**3,239,818**	**3,235,899**	**3,309,550**
Revenue (million dollars)					
Residential	90,501	90,694	93,164	93,142	97,086
Commercial	67,827	70,482	71,769	70,492	73,704
Industrial	47,385	46,772	46,550	45,056	46,465
Other[1]	6,741	7,110	6,863	6,783	6,988
U.S. Total	**212,455**	**215,059**	**218,346**	**215,473**	**224,243**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in State ''retail wheeling'' programs. For 1996, 1997, 1998, 1999, and 2000 these were 3.3 million megawatthours, 5.8 million megawatthours, 24.4 million megawatthours, 76.2 million megawatthours, and 111.9 million (adjusted) megawatthours, respectively. For more detailed information regarding the sales in restructured markets, see the Energy Information Administration's publication, *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year. •Bundled consumers are those provided full electric service (energy and delivery) by a single utility entity. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 3b. Average Revenue per Kilowatthour (Bundled Consumers) for U.S. Electric Utilities by Sector, 1996 Through 2000

(Cents)

Sector	1996	1997	1998	1999	2000
Residential	8.36	8.43	8.26	8.16	8.21
Commercial	7.64	7.59	7.41	7.26	7.36
Industrial	4.60	4.53	4.48	4.43	4.57
Other[1]	6.91	6.91	6.63	6.35	6.48
All Sectors	**6.86**	**6.85**	**6.74**	**6.66**	**6.78**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in State ''retail wheeling'' pilot programs. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 4. U.S. Electric Utility Sales to Bundled Ultimate Consumers by Sector, Census Division, and State, 1999 and 2000
(Million Kilowatthours)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1999	2000	1999	2000	1999	2000	1999	2000	1999	2000
New England	**111,472**	**107,955**	**40,949**	**38,779**	**43,893**	**44,176**	**25,167**	**23,543**	**1,463**	**1,457**
Connecticut	29,803	29,952	11,619	11,645	11,834	11,932	5,836	5,811	515	564
Maine	11,944	6,405	3,704	1,259	3,491	2,834	4,687	2,287	61	25
Massachusetts	47,821	48,862	17,392	17,534	20,459	20,859	9,409	9,843	560	625
New Hampshire	9,723	9,976	3,572	3,638	3,512	3,622	2,510	2,584	128	131
Rhode Island	6,655	7,120	2,663	2,664	2,701	3,019	1,137	1,372	154	65
Vermont	5,527	5,639	1,999	2,037	1,896	1,910	1,587	1,646	45	46
Middle Atlantic	**296,439**	**285,468**	**108,332**	**107,068**	**106,601**	**99,635**	**67,152**	**64,843**	**14,355**	**13,923**
New Jersey	70,582	62,819	24,550	24,064	32,436	27,316	13,071	10,933	525	506
New York	129,834	124,508	42,538	41,556	49,366	47,014	25,202	23,483	12,729	12,455
Pennsylvania	96,023	98,142	41,244	41,448	24,799	25,305	28,879	30,427	1,102	962
East North Central	**560,270**	**553,982**	**165,220**	**165,913**	**154,212**	**154,542**	**225,609**	**217,558**	**15,229**	**15,969**
Illinois	132,237	125,596	39,623	40,146	41,891	39,183	41,612	36,510	9,111	9,756
Indiana	96,735	97,775	28,806	28,649	20,161	20,468	47,230	48,040	539	618
Michigan	103,480	104,371	30,661	30,700	35,062	35,812	36,808	36,928	948	930
Ohio	164,271	161,093	46,629	46,488	39,461	40,757	74,293	69,918	3,888	3,930
Wisconsin	63,547	65,146	19,502	19,929	17,638	18,321	25,665	26,162	743	734
West North Central	**238,073**	**249,479**	**83,516**	**87,927**	**66,343**	**70,358**	**82,445**	**84,581**	**5,769**	**6,613**
Iowa	38,034	39,088	11,867	12,029	8,269	8,375	16,499	17,127	1,399	1,558
Kansas	33,820	35,921	11,347	12,528	11,822	12,511	10,215	10,222	436	660
Minnesota	57,399	59,782	17,998	18,629	10,909	11,580	27,764	28,842	729	730
Missouri	68,976	72,643	27,766	29,581	24,042	25,875	16,122	16,080	1,046	1,106
Nebraska	22,810	24,349	7,929	8,346	6,661	7,041	6,883	7,276	1,336	1,686
North Dakota	9,112	9,413	3,307	3,390	2,350	2,554	3,013	3,031	443	438
South Dakota	7,922	8,283	3,302	3,423	2,291	2,422	1,949	2,003	381	435
South Atlantic	**688,419**	**718,311**	**276,708**	**291,763**	**224,727**	**236,288**	**165,256**	**168,062**	**21,728**	**22,198**
Delaware	10,494	10,772	3,532	3,574	3,348	3,656	3,559	3,493	54	49
District of Columbia	10,418	10,616	1,643	1,624	8,146	8,332	249	273	380	387
Florida	187,270	195,843	93,846	99,006	69,055	72,130	18,579	18,884	5,790	5,824
Georgia	112,656	119,185	41,767	44,560	34,093	36,951	35,255	36,085	1,541	1,589
Maryland	59,086	60,620	23,342	23,914	24,988	25,782	9,936	10,066	819	858
North Carolina	115,015	119,855	43,648	46,537	35,069	36,859	34,165	34,252	2,133	2,208
South Carolina	73,304	77,012	23,699	25,270	16,585	17,483	32,117	33,308	903	951
Virginia	93,032	96,715	35,779	37,541	26,968	28,299	20,269	20,619	10,017	10,256
West Virginia	27,144	27,693	9,452	9,738	6,473	6,796	11,126	11,083	92	76
East South Central	**296,659**	**302,904**	**101,342**	**105,946**	**67,746**	**70,197**	**121,816**	**120,869**	**5,756**	**5,893**
Alabama	80,401	83,524	27,048	28,756	18,145	19,057	34,533	35,034	676	677
Kentucky	79,098	78,316	22,548	23,374	13,222	13,933	40,054	37,689	3,274	3,320
Mississippi	43,980	45,336	16,321	17,193	11,151	11,451	15,735	15,856	772	836
Tennessee	93,180	95,728	35,425	36,622	25,228	25,757	31,493	32,289	1,035	1,060
West South Central	**466,636**	**490,128**	**167,364**	**179,125**	**117,742**	**124,935**	**161,176**	**164,742**	**20,355**	**21,326**
Arkansas	39,789	41,611	14,045	14,871	8,374	8,746	16,680	17,268	690	726
Louisiana	78,267	80,690	26,426	27,719	17,581	18,225	31,484	31,950	2,776	2,795
Oklahoma	46,737	49,564	18,301	19,640	12,398	13,115	13,271	13,935	2,766	2,874
Texas	301,844	318,263	108,591	116,895	79,388	84,848	99,741	101,588	14,124	14,931
Mountain	**210,123**	**221,475**	**67,411**	**72,738**	**67,990**	**73,658**	**66,795**	**67,104**	**7,927**	**7,975**
Arizona	57,662	61,001	22,517	24,844	19,776	21,282	12,456	11,975	2,912	2,900
Colorado	40,571	43,020	13,131	14,029	17,006	17,989	9,521	9,955	913	1,047
Idaho	21,846	22,834	6,806	7,006	6,450	7,068	8,295	8,408	296	352
Montana	12,132	12,489	3,664	3,901	3,025	3,467	5,108	4,809	334	312
Nevada	26,253	27,792	8,386	9,406	6,049	6,548	10,861	11,239	958	598
New Mexico	17,998	18,786	4,645	4,936	5,887	6,672	5,922	5,481	1,543	1,698
Utah	21,879	23,185	6,236	6,514	7,282	7,884	7,568	7,917	792	870
Wyoming	11,782	12,368	2,025	2,103	2,514	2,748	7,065	7,321	178	196
Pacific	**353,133**	**364,847**	**125,365**	**129,259**	**116,075**	**121,804**	**97,777**	**101,550**	**13,916**	**12,233**
California	211,981	221,323	74,490	78,011	78,154	82,524	49,595	53,105	9,743	7,683
Oregon	46,996	50,330	18,058	18,212	14,912	15,289	13,558	16,353	468	476
Washington	94,155	93,194	32,817	33,036	23,009	23,991	34,624	32,092	3,706	4,075
Pacific Noncontiguous	**14,674**	**15,001**	**4,555**	**4,620**	**5,273**	**5,272**	**4,591**	**4,870**	**255**	**238**
Alaska	5,293	5,310	1,866	1,855	2,385	2,236	844	1,037	198	182
Hawaii	9,381	9,691	2,689	2,765	2,887	3,036	3,748	3,834	57	56
U. S. Total	**3,235,899**	**3,309,550**	**1,140,761**	**1,183,137**	**970,601**	**1,000,865**	**1,017,783**	**1,017,723**	**106,754**	**107,824**

1 Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in State ''retail wheeling'' programs. For 1999 and 2000, these sales were 76.2 million megawatthours and 111.9 million megawatthours (adjusted), respectively. For more detailed information regarding the sales in restructured markets, see the Energy Information Administration's publication, *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 5. Number of Bundled Ultimate Consumers Served by U.S. Electric Utilities by Sector, Census Division, and State, 1999 and 2000
(Thousands)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1999	2000	1999	2000	1999	2000	1999	2000	1999	2000
New England	**6,468**	**6,059**	**5,715**	**5,316**	**682**	**688**	**29**	**28**	**42**	**26**
Connecticut	1,503	1,506	1,362	1,364	131	131	6	6	5	5
Maine	724	255	626	191	76	61	3	2	19	1
Massachusetts	2,827	2,871	2,496	2,524	306	321	14	14	11	12
New Hampshire	624	633	532	540	83	85	3	3	6	5
Rhode Island	468	467	419	414	45	50	2	2	1	1
Vermont	322	326	280	283	40	41	*	*	1	1
Middle Atlantic	**16,209**	**16,081**	**14,312**	**14,223**	**1,800**	**1,763**	**45**	**43**	**52**	**50**
New Jersey	3,605	3,567	3,148	3,143	434	402	13	12	11	10
New York	7,499	7,436	6,602	6,546	856	849	9	8	33	32
Pennsylvania	5,104	5,078	4,562	4,534	510	513	24	24	8	7
East North Central	**20,260**	**20,615**	**18,099**	**18,407**	**2,005**	**2,048**	**73**	**73**	**83**	**88**
Illinois	5,140	5,279	4,622	4,749	481	490	5	5	31	35
Indiana	2,817	2,865	2,505	2,546	284	291	18	19	9	10
Michigan	4,534	4,583	4,058	4,099	451	460	14	14	12	10
Ohio	5,197	5,262	4,630	4,684	517	528	30	30	20	20
Wisconsin	2,571	2,626	2,283	2,329	271	278	5	6	12	13
West North Central	**9,366**	**9,499**	**8,093**	**8,206**	**1,097**	**1,110**	**51**	**51**	**126**	**131**
Iowa	1,417	1,437	1,229	1,243	168	172	4	4	17	18
Kansas	1,330	1,353	1,118	1,136	181	187	14	14	17	16
Minnesota	2,276	2,304	2,017	2,051	224	217	11	11	23	24
Missouri	2,737	2,781	2,405	2,440	308	317	10	10	14	14
Nebraska	886	899	718	725	118	120	8	9	41	45
North Dakota	341	343	286	288	48	47	2	2	5	6
South Dakota	380	384	319	322	50	51	2	2	9	9
South Atlantic	**24,483**	**25,044**	**21,503**	**21,984**	**2,716**	**2,791**	**77**	**79**	**188**	**191**
Delaware	370	377	331	335	38	41	1	1	1	1
District of Columbia	220	226	194	198	26	27	*	*	*	*
Florida	7,961	8,153	7,001	7,170	863	882	23	26	74	75
Georgia	3,732	3,839	3,296	3,385	393	411	11	10	32	32
Maryland	2,175	2,210	1,952	1,983	213	218	8	7	1	2
North Carolina	4,006	4,106	3,474	3,561	501	514	13	13	18	18
South Carolina	2,012	2,059	1,725	1,764	267	274	5	5	16	16
Virginia	3,063	3,123	2,716	2,767	299	307	5	5	42	43
West Virginia	944	952	813	820	116	117	11	11	3	3
East South Central	**8,310**	**8,436**	**7,151**	**7,251**	**1,082**	**1,106**	**20**	**20**	**58**	**59**
Alabama	2,225	2,263	1,901	1,930	304	313	6	6	14	13
Kentucky	1,991	2,028	1,735	1,765	227	232	7	8	23	23
Mississippi	1,346	1,372	1,152	1,173	180	185	5	4	9	10
Tennessee	2,748	2,773	2,363	2,383	370	376	2	2	12	12
West South Central	**14,143**	**14,486**	**12,279**	**12,534**	**1,597**	**1,658**	**122**	**118**	**146**	**176**
Arkansas	1,339	1,363	1,160	1,178	140	144	26	26	14	16
Louisiana	2,042	2,075	1,791	1,819	213	218	15	15	22	23
Oklahoma	1,729	1,748	1,495	1,515	204	202	15	15	15	16
Texas	9,033	9,300	7,832	8,023	1,041	1,093	65	61	94	122
Mountain	**8,070**	**8,333**	**6,950**	**7,167**	**933**	**981**	**39**	**31**	**148**	**154**
Arizona	2,122	2,193	1,897	1,960	200	212	5	5	19	17
Colorado	2,048	2,117	1,713	1,771	236	244	3	4	96	98
Idaho	617	633	517	531	91	92	7	6	3	3
Montana	481	492	393	401	69	75	4	1	14	15
Nevada	871	910	760	794	108	112	1	1	1	2
New Mexico	827	853	712	728	102	113	6	1	6	11
Utah	834	858	739	760	81	85	9	8	5	5
Wyoming	271	277	219	222	46	48	4	4	3	3
Pacific Contiguous	**17,242**	**16,777**	**15,126**	**14,818**	**1,963**	**1,821**	**72**	**69**	**81**	**70**
California	12,899	12,359	11,327	10,954	1,487	1,333	41	42	45	30
Oregon	1,635	1,666	1,409	1,434	203	209	12	12	11	11
Washington	2,707	2,752	2,390	2,430	273	279	19	15	24	28
Pacific Noncontiguous	**691**	**701**	**591**	**599**	**90**	**92**	**1**	**2**	**10**	**8**
Alaska	270	274	227	231	37	38	*	1	6	4
Hawaii	422	427	364	368	53	54	1	1	4	4
U. S. Average	**125,243**	**126,030**	**109,817**	**110,506**	**13,964**	**14,058**	**527**	**513**	**934**	**954**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
* =Value less than 0.5 thousand.

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in State ''retail wheeling'' pilot programs. •Totals may not equal sum of components because of independent rounding. •The number of ultimate consumers is an average of the number of consumers at the close of each month.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 6. Revenue from U.S. Electric Utility Sales to Bundled Ultimate Consumers by Sector, Census Division, and State, 1999 and 2000

(Million Dollars)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1999	2000	1999	2000	1999	2000	1999	2000	1999	2000
New England	**10,828**	**10,596**	**4,578**	**4,303**	**4,167**	**4,220**	**1,895**	**1,879**	**188**	**193**
Connecticut	2,968	2,852	1,332	1,264	1,147	1,106	433	425	56	57
Maine	1,167	638	484	163	367	305	301	164	15	6
Massachusetts	4,382	4,677	1,755	1,847	1,821	1,919	729	814	77	96
New Hampshire	1,142	1,123	494	478	400	394	231	235	16	16
Rhode Island	600	726	270	300	229	293	84	119	17	13
Vermont	568	579	243	251	202	203	117	120	6	6
Middle Atlantic	**27,920**	**27,600**	**12,252**	**12,181**	**10,642**	**10,497**	**3,716**	**3,676**	**1,310**	**1,247**
New Jersey	7,054	5,950	2,798	2,476	3,160	2,522	1,005	892	91	60
New York	13,503	13,978	5,665	5,830	5,523	5,897	1,203	1,167	1,113	1,084
Pennsylvania	7,363	7,672	3,790	3,875	1,959	2,078	1,508	1,617	106	102
East North Central	**35,761**	**35,458**	**13,653**	**13,634**	**11,132**	**11,200**	**10,000**	**9,630**	**976**	**994**
Illinois	9,226	8,774	3,500	3,546	3,095	2,950	2,088	1,736	542	541
Indiana	5,117	5,068	2,005	1,967	1,220	1,214	1,840	1,829	52	58
Michigan	7,387	7,428	2,676	2,617	2,755	2,829	1,860	1,882	96	100
Ohio	10,516	10,470	4,046	4,002	3,025	3,102	3,214	3,126	232	240
Wisconsin	3,515	3,717	1,426	1,502	1,037	1,104	999	1,057	53	54
West North Central	**14,100**	**14,781**	**6,146**	**6,467**	**4,057**	**4,274**	**3,529**	**3,635**	**368**	**406**
Iowa	2,255	2,319	991	1,007	533	551	642	665	88	95
Kansas	2,102	2,254	867	959	739	782	457	465	39	48
Minnesota	3,344	3,511	1,334	1,400	688	736	1,267	1,319	55	56
Missouri	4,184	4,370	1,976	2,084	1,436	1,508	707	712	65	67
Nebraska	1,212	1,292	517	545	362	382	246	263	86	103
North Dakota	500	512	215	218	145	155	122	121	19	18
South Dakota	503	523	245	254	153	161	89	90	16	19
South Atlantic	**43,860**	**45,722**	**21,374**	**22,479**	**14,252**	**14,877**	**6,910**	**6,987**	**1,324**	**1,379**
Delaware	747	664	324	305	248	224	168	128	7	7
District of Columbia	777	798	131	130	609	629	11	13	25	26
Florida	12,819	13,526	7,253	7,696	4,297	4,511	886	913	383	405
Georgia	7,025	7,404	3,159	3,386	2,272	2,401	1,463	1,481	130	135
Maryland	4,158	4,084	1,959	1,903	1,703	1,689	423	415	72	76
North Carolina	7,412	7,767	3,486	3,709	2,221	2,345	1,560	1,569	144	144
South Carolina	4,085	4,332	1,790	1,916	1,045	1,110	1,196	1,246	54	60
Virginia	5,454	5,742	2,677	2,823	1,498	1,598	778	804	501	518
West Virginia	1,383	1,405	593	610	358	371	423	417	8	8
East South Central	**15,482**	**15,962**	**6,507**	**6,814**	**4,161**	**4,321**	**4,466**	**4,469**	**348**	**357**
Alabama	4,456	4,687	1,901	2,028	1,187	1,254	1,320	1,357	47	48
Kentucky	3,299	3,277	1,257	1,279	696	717	1,196	1,136	149	146
Mississippi	2,486	2,652	1,102	1,191	690	734	632	657	61	70
Tennessee	5,242	5,346	2,247	2,316	1,586	1,617	1,319	1,320	90	93
West South Central	**27,566**	**31,181**	**12,334**	**13,919**	**7,518**	**8,467**	**6,468**	**7,386**	**1,247**	**1,409**
Arkansas	2,262	2,399	1,043	1,109	488	519	688	726	43	46
Louisiana	4,550	5,229	1,882	2,127	1,159	1,308	1,338	1,599	172	195
Oklahoma	2,511	2,912	1,208	1,380	692	805	478	570	133	157
Texas	18,243	20,640	8,201	9,304	5,179	5,835	3,964	4,491	899	1,011
Mountain	**12,372**	**13,111**	**5,015**	**5,395**	**4,265**	**4,533**	**2,677**	**2,764**	**415**	**419**
Arizona	4,170	4,426	1,922	2,096	1,484	1,568	628	631	136	131
Colorado	2,415	2,528	969	1,025	954	998	417	423	75	81
Idaho	870	953	358	377	271	300	228	262	13	15
Montana	607	592	249	253	192	198	145	119	21	22
Nevada	1,556	1,715	598	685	403	441	518	560	38	29
New Mexico	1,184	1,236	401	413	443	471	252	257	89	96
Utah	1,064	1,123	391	410	385	412	254	265	33	36
Wyoming	506	537	128	137	133	145	236	246	9	10
Pacific Contiguous	**25,943**	**27,938**	**10,690**	**11,227**	**9,712**	**10,647**	**4,969**	**5,513**	**572**	**551**
California	19,792	21,370	7,978	8,461	7,856	8,707	3,552	3,834	406	368
Oregon	2,287	2,460	1,038	1,071	737	774	481	582	31	34
Washington	3,864	4,107	1,673	1,695	1,119	1,166	936	1,097	136	149
Pacific Noncontiguous	**1,641**	**1,895**	**593**	**666**	**587**	**668**	**425**	**526**	**35**	**34**
Alaska	517	535	208	212	219	219	62	78	28	26
Hawaii	1,123	1,360	384	454	368	450	364	448	7	8
U. S. Total	**215,473**	**224,243**	**93,142**	**97,086**	**70,492**	**73,704**	**45,056**	**46,465**	**6,783**	**6,988**

1 Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in State ''retail wheeling'' pilot programs. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 7. Average Revenue per Kilowatthour (Bundled Consumers) for U.S. Electric Utilities by Sector, Ceneus Division, and State, 1999 and 2000
(Cents)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1999	2000	1999	2000	1999	2000	1999	2000	1999	2000
New England	**9.71**	**9.81**	**11.18**	**11.10**	**9.49**	**9.55**	**7.53**	**7.98**	**12.83**	**13.27**
Connecticut	9.96	9.52	11.46	10.86	9.69	9.27	7.42	7.32	10.93	10.06
Maine	9.77	9.96	13.07	12.92	10.51	10.77	6.42	7.18	24.29	21.70
Massachusetts	9.16	9.57	10.09	10.53	8.90	9.20	7.75	8.27	13.73	15.34
New Hampshire	11.75	11.26	13.84	13.14	11.39	10.87	9.21	9.10	12.78	12.41
Rhode Island	9.02	10.20	10.13	11.28	8.49	9.71	7.39	8.70	11.20	20.44
Vermont	10.28	10.27	12.17	12.30	10.67	10.61	7.35	7.31	13.32	12.20
Middle Atlantic	**9.42**	**9.67**	**11.31**	**11.38**	**9.98**	**10.54**	**5.53**	**5.67**	**9.13**	**8.95**
New Jersey	9.99	9.47	11.40	10.29	9.74	9.23	7.69	8.16	17.43	11.94
New York	10.40	11.23	13.32	14.03	11.19	12.54	4.77	4.97	8.74	8.71
Pennsylvania	7.67	7.82	9.19	9.35	7.90	8.21	5.22	5.31	9.63	10.60
East North Central	**6.38**	**6.40**	**8.26**	**8.22**	**7.22**	**7.25**	**4.43**	**4.43**	**6.41**	**6.22**
Illinois	6.98	6.99	8.83	8.83	7.39	7.53	5.02	4.76	5.95	5.55
Indiana	5.29	5.18	6.96	6.87	6.05	5.93	3.89	3.81	9.70	9.37
Michigan	7.14	7.12	8.73	8.53	7.86	7.90	5.05	5.10	10.17	10.77
Ohio	6.40	6.50	8.68	8.61	7.67	7.61	4.33	4.47	5.96	6.10
Wisconsin	5.53	5.71	7.31	7.53	5.88	6.03	3.89	4.04	7.11	7.40
West North Central	**5.92**	**5.92**	**7.36**	**7.35**	**6.12**	**6.07**	**4.28**	**4.30**	**6.38**	**6.13**
Iowa	5.93	5.93	8.35	8.37	6.45	6.57	3.89	3.89	6.30	6.13
Kansas	6.22	6.27	7.64	7.65	6.25	6.25	4.47	4.55	8.91	7.29
Minnesota	5.83	5.87	7.41	7.52	6.31	6.36	4.56	4.57	7.49	7.60
Missouri	6.07	6.02	7.12	7.04	5.97	5.83	4.38	4.43	6.26	6.02
Nebraska	5.31	5.31	6.52	6.53	5.44	5.42	3.57	3.61	6.47	6.10
North Dakota	5.49	5.44	6.50	6.44	6.19	6.08	4.04	3.98	4.23	4.19
South Dakota	6.35	6.32	7.42	7.42	6.70	6.64	4.55	4.49	4.17	4.30
South Atlantic	**6.37**	**6.37**	**7.72**	**7.70**	**6.34**	**6.30**	**4.18**	**4.16**	**6.10**	**6.21**
Delaware	7.12	6.17	9.17	8.54	7.39	6.12	4.73	3.68	13.24	14.19
District of Columbia	7.45	7.52	8.00	8.03	7.47	7.55	4.59	4.74	6.55	6.67
Florida	6.85	6.91	7.73	7.77	6.22	6.25	4.77	4.84	6.61	6.96
Georgia	6.24	6.21	7.56	7.60	6.67	6.50	4.15	4.10	8.47	8.51
Maryland	7.04	6.74	8.39	7.96	6.82	6.55	4.26	4.13	8.77	8.89
North Carolina	6.44	6.48	7.99	7.97	6.33	6.36	4.57	4.58	6.74	6.53
South Carolina	5.57	5.62	7.55	7.58	6.30	6.35	3.72	3.74	5.98	6.29
Virginia	5.86	5.94	7.48	7.52	5.55	5.65	3.84	3.90	5.00	5.05
West Virginia	5.09	5.07	6.27	6.27	5.53	5.46	3.80	3.76	9.10	9.88
East South Central	**5.22**	**5.27**	**6.42**	**6.43**	**6.14**	**6.16**	**3.67**	**3.70**	**6.04**	**6.06**
Alabama	5.54	5.61	7.03	7.05	6.54	6.58	3.82	3.87	7.02	7.12
Kentucky	4.17	4.18	5.58	5.47	5.27	5.14	2.99	3.01	4.55	4.40
Mississippi	5.65	5.85	6.75	6.93	6.19	6.41	4.02	4.14	7.93	8.33
Tennessee	5.63	5.58	6.34	6.33	6.29	6.28	4.19	4.09	8.71	8.79
West South Central	**5.91**	**6.36**	**7.37**	**7.77**	**6.38**	**6.78**	**4.01**	**4.48**	**6.12**	**6.61**
Arkansas	5.68	5.77	7.43	7.45	5.82	5.93	4.12	4.20	6.26	6.39
Louisiana	5.81	6.48	7.12	7.67	6.59	7.18	4.25	5.00	6.20	6.98
Oklahoma	5.37	5.88	6.60	7.03	5.58	6.14	3.60	4.09	4.80	5.46
Texas	6.04	6.49	7.55	7.96	6.52	6.88	3.97	4.42	6.36	6.77
Mountain	**5.89**	**5.92**	**7.44**	**7.42**	**6.27**	**6.15**	**4.01**	**4.12**	**5.23**	**5.26**
Arizona	7.23	7.26	8.53	8.44	7.51	7.37	5.04	5.27	4.66	4.53
Colorado	5.95	5.88	7.38	7.31	5.61	5.55	4.38	4.25	8.23	7.77
Idaho	3.98	4.17	5.26	5.39	4.20	4.24	2.74	3.11	4.47	4.13
Montana	5.01	4.74	6.78	6.48	6.35	5.70	2.84	2.48	6.34	7.18
Nevada	5.93	6.17	7.13	7.28	6.66	6.74	4.77	4.98	3.94	4.77
New Mexico	6.58	6.58	8.62	8.36	7.53	7.06	4.25	4.69	5.76	5.64
Utah	4.86	4.84	6.27	6.29	5.29	5.23	3.36	3.35	4.21	4.14
Wyoming	4.30	4.34	6.34	6.50	5.28	5.29	3.34	3.36	5.27	4.87
Pacific Contiguous	**7.35**	**7.66**	**8.53**	**8.69**	**8.37**	**8.74**	**5.08**	**5.43**	**4.11**	**4.50**
California	9.34	9.66	10.71	10.85	10.05	10.55	7.16	7.22	4.16	4.79
Oregon	4.87	4.89	5.75	5.88	4.94	5.06	3.55	3.56	6.68	7.10
Washington	4.10	4.41	5.10	5.13	4.86	4.86	2.70	3.42	3.66	3.65
Pacific Noncontiguous	**11.18**	**12.63**	**13.01**	**14.42**	**11.14**	**12.68**	**9.27**	**10.81**	**13.83**	**14.31**
Alaska	9.78	10.08	11.16	11.45	9.20	9.77	7.32	7.56	14.16	14.17
Hawaii	11.97	14.03	14.30	16.41	12.74	14.81	9.70	11.69	12.66	14.76
U. S. Average	**6.66**	**6.78**	**8.16**	**8.21**	**7.26**	**7.36**	**4.43**	**4.57**	**6.35**	**6.48**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in State ''retail wheeling'' pilot programs. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

U.S. Electric Utility Financial Statistics

This chapter presents data on the financial results of operations for major U.S. investor-owned and publicly owned electric utilities. Composite financial data on other segments of the U.S. electric utility industry, for example, Federal electric utilities and rural electric cooperatives, are not included. The data exhibited consist of the Composite Statement of Income, the Composite Balance Sheet, Composite Financial Indicators, and Revenue and Expense Statistics. Historical data are provided for a 5-year period on major U.S. investor-owned and U.S. publicly owned electric utilities. Statistics on the average operating expenses for all plants owned by major U.S. investor-owned electric utilities are also provided.

Increasing competition and the pending shift to deregulation are causing utilities to position themselves to meet a changing industry structure through increased operating efficiencies, mergers, and restructuring. In an effort to restructure, utilities may have sold assets such as generating units, formed unregulated utility subsidiaries, or invested in nonutility power producers or foreign enterprises.

Background

Today, virtually all investor-owned electric utilities are subject to State and Federal regulatory jurisdiction. State commissions have the authority to regulate electric rates of utilities engaged in providing service to ultimate consumers (retail sales) and to oversee the issuance of mortgage bonds, debentures, notes, preferred stock, and common stock. The Federal Energy Regulatory Commission (FERC) regulates, among other things, electric rates for interstate wholesale transactions. The ratemaking process sets rates at levels that cover all operating expenses and taxes with a remaining balance that will enable a utility to pay a fair return on funds invested by the stockholders.

A component of any economic regulatory activity is the determination of financing and accounting rules. As a consequence of regulatory jurisdiction, regulations for financing and accounting are more critical to the electric power industry than to most other nonregulated industries. Both FERC and State commissions normally use quasi-judicial proceedings for financial and accounting regulation.

Many of the publicly owned electric utilities are self-regulated, for example, the City of Dover, Delaware), while some fall under the jurisdiction of the public utility commission within the State(s) where they provide electricity to ultimate consumers (as in the State of Ohio). Because of the absence of any requirement for reporting to a specific regulatory body, the accounting practices and policies of publicly owned electric utilities vary greatly. Many publicly owned electric utilities use the FERC Uniform System of Accounts or variations of this (and other) accounting systems. As a result, the composite statistics provided must be viewed with an appropriate degree of caution.

Electric utilities must submit data for a 12-month period (which does not necessarily end on December 31) and show consistency in their methods and reporting dates. Because of the respondent burden in preparing this information, publicly owned electric utilities are permitted to use the year-end period on which their fiscal practices are based. Data are provided for the major publicly owned electric utilities by generator and nongenerators.

Composite Statement of Income

This statement provides a summary of the revenue collected from consumers in return for services rendered within the reporting period; reflects the costs incurred by the electric utility in the production and delivery of electricity; and reports the net income or profit that remains for the owners of the business. Because of the unique nature of regulated electric utilities, the income statement that is standard to other nonregulated industries has been recast to reflect the reporting conventions in the electric power industry. For example, accounting for capital used in construction requires additional reporting on the income statement because of the perpetual nature of construction work in progress. Also, on occasion, electric utilities are required to defer the recovery of certain costs and earnings from consumers until a future period. This introduces additional accounting requirements, which must be reflected on all financial statements.

Composite Balance Sheet

The balance sheet represents an accounting at a particular time. For this section, the composite balance sheets are presented for major investor-owned electric utilities at the end of a calendar year and for major publicly owned electric utilities for the 12-month fiscal year ending in 2000. A summary of plant, property, and cash held by the electric utilities, as well as the receivables of the electric utilities, are represented as assets on the composite balance sheet. Future funds obligated by the electric utilities to acquire assets are shown as liabilities and any increased investment by stockholders is shown as capital on the balance sheet.

The standard balance sheet used in the electric power industry emphasizes capital intensity while the balance sheet used by nonregulated industries emphasizes liquidity.

Composite Financial Indicators

The financial statement accounts presented in this chapter represent compiled statistics resulting from the activity of the selected electric utilities. The measurement of how well the electric utility industry performs in different areas can be approximated by comparing some of the asset and income accounts to other relevant accounts. Using the financial statement information, some basic indicators that can be used to analyze or assess the financial condition of the industry are provided. The method used to derive these selected financial indicators is ratio analysis.

Activity ratios of the investor-owned electric utilities evaluate how assets are managed. The electric utility industry is one of the most capital intensive industries in the United States, and activity ratios are paramount indicators of the magnitude of this capital intensity. These ratios demonstrate the financial relationship that exists between the assets and the revenue, sales, and income that these fixed and total assets generate. The ratios on *electric-fixed-asset (net plant) turnover* and *total-asset turnover* assess the efficient use of assets in the generation of income.

Leverage ratios of the investor-owned electric utilities summarize the overall debt burden and debt structure. In addition, these ratios indicate the financial ability to meet debt service requirements and how well management uses leverage to increase the value of the stockholders' investment. The financial soundness of an industry is directly related to the ability of the industry to raise capital and to provide a reasonable return on the capital invested. To measure the ability to do this, a number of indicators are used. *Current assets to current liabilities* is a measure of liquidity. For example, do the investor-owned electric utilities have sufficient cash and other assets (current) that can be quickly converted to cash to cover maturing obligations (current liabilities)? *Long-term debt to capitalization, preferred stock to capitalization,* and *common-stock equity to capitalization* portray the financial structure and highlight the extent to which debt and other fixed obligations are used to finance operations. *Total debt to total assets* shows the amount of debt that has been incurred in relationship to the total assets possessed. As the value of this ratio increases, the financial risks also become greater and more apparent. *Common-stock equity to total assets* evaluates financial strength. As net worth increases in relationship to total assets, the debt portion is decreased and financial risks are lowered. *Interest coverage before taxes without AFUDC* (Allowance for Funds Used During Construction), a noncash source of income, is an indicator of the ability of the investor-owned electric utility to ensure its payment of annual interest costs and maintain its credit ratings.

Profitability ratios of the investor-owned electric utilities indicate operating effectiveness and are used to further evaluate the management of income. The *profit margin* is equal to net income divided by revenue. This widely used ratio represents the overall measure of income performance. *Return on average-common-stock equity* measures the rate of return on equity capital invested. Since one of the main objectives of management is to earn the highest return permissible, this ratio is the best single measure of the effectiveness of management from the perspective of the stockholders. *Return on investment* measures the overall rate of return that has been earned on assets. This ratio, determined by dividing total assets into net income, provides an indicator of overall financial performance.

Ratios on the publicly owned electric utilities are provided to assist in understanding the financial performance of the publicly owned segment of the industry. Six ratios are calculated from the statement of income. *Electric utility plant per dollar of revenue* highlights the capital intensity of the utility. *Current assets to current liabilities* provides a measure of the ease by which the utility can meet its current obligations. *Electric utility plant as a percent of total assets* represents the total gross investment in electric plant divided by the total assets. A significant variation in this ratio should signal a relatively fundamental change in the activities of the electric utility. *Net electric utility plant as a percent of total assets* represents the remaining book value and a significant variation should signal a change for the electric utility. *Debt as a percent of total liabilities* represents the amount of debt compared to total liabilities and other credits. *Accumulated provision for depreciation as a percent of total electric plant* measures the cost of recovery of the use of the assets over a period of time for an electric utility; an increase indicates that plant asset life is being used up. Five ratios are calculated from the balance sheet. The ratios of *electric operating and maintenance expenses, electric depreciation and amortization, taxes and tax equivalents,* and *interest on long-term debt* to *electric operating revenue* are indicators of how resources were used to produce income. *Net income per dollar of revenue* provides the amount of the revenue dollar that exceeds expenses and deductions.

Because a number of initiatives are being considered to promote increased competition in the electric power industry, three operating ratios that measure specific costs associated with the sale of each kilowatthour of electricity have been included. *Purchase Power Cents Per Kilowatthour* is the ratio of the cost of purchased power to the number of kilowatthours purchased. This ratio measures the purchased power component of power supply cost. *Generated Cents Per Kilowatthour* is the ratio of the cost of labor, materials used and expenses incurred in the production of electric generation. This ratio measures the generation component of production expenses. *Total Power Supply Per Kilowatthour Sold* is the ratio of the total cost of power supply to total sales to both ultimate and resale consumers. This ratio measures all power supply costs, including generation and purchase power, associated with the sale of each kilowatthour of electricity.

Revenue and Expense Statistics

Summary revenue and expense statistics are basic to any analysis of the operating soundness of an electric utility. To conduct this analysis, it is necessary to separate the electric utility revenue and expense information from other utility revenue and expense data. Emphasis is placed on total electric operating expenses. Data are presented so that operating costs are separate from maintenance, depreciation, and taxes. For comparative purposes, the ratio of income from utility operations is also included.

Electric Operating Expenses

Before consumers can be provided with electricity, it first must be either produced (generated) or purchased, then transmitted to the general area where it will be consumed, and finally distributed to the individual consumer. Hence, electric utilities separate their costs of providing power into four functional areas: *generation, transmission, distribution,* and *administration.* Costs incurred at the generation site for the production of electricity are generally referred to as operating expenses.

Operating expenses include recurring expenses to operate and maintain the physical condition or operating efficiency of the plant. These expenses include wages and benefits of the operators, plant maintenance, security, supervision, materials (such as spare parts), and supplies (except fuel consumed during plant operation and maintenance). Fuel expenses include the costs of purchasing, handling, preparing, and transporting fuel. Operating expenses do not include capital carrying costs, such as interest on debt, return on equity, depreciation, amortization expenses, and associated taxes. Capital carrying costs must be added to the operating expenses to obtain total generation expenses.

Investor-owned electric utilities are the major sources of total electricity generation, accounting for about 80 percent of total utility generation in the United States in 2000. Publicly owned electric utilities were responsible for about 10 percent of the total U.S. utility generation, while the remainder was accounted for by Federal and cooperative electric utilities. Operating expenses per unit of output (kilowatthour) for the major investor-owned electric utilities from 1994 through 1998 are provided grouped into the following categories: fossil-fueled steam, nuclear, hydroelectric, and other (includes gas turbine and small scale electric plants).

Data Sources

Financial Statistics. The financial statistics reported in this chapter on the investor-owned electric utilities are compiled from data extracted from the FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others.” This survey is a restricted-universe census used annually to collect detailed accounting, financial, and operating data from major investor-owned electric utilities having, in each of the last three consecutive years, sales or transmission service that exceeds one or more of the following:

1 million megawatthours of total annual sales.
100 megawatthours of annual sales for resale.
500 megawatthours of annual power exchanges delivered.
500 megawatthours of annual wheeling for others (deliveries plus losses).

Effective for 1997 through 2000, FERC Form 1 data in this publication have been edited by Navigant Consulting, Inc. Detailed data for 1996 are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.* This publication has now been discontinued. However, complete 1997 through 2000 FERC Form 1 data may be obtained on a utility-by-utility basis from the FERC World Wide Website (http://www.ferc.fed.us).

The financial statistics on the publicly owned electric utilities are compiled from data extracted from the Form EIA-412, “Annual Report of Public Electric Utilities.” This form is a restricted-universe census used annually to collect detailed accounting, financial, and operating data from major publicly owned electric utilities having, in each of the last 2 consecutive years, sales that exceed either of the following:

150,000 megawatthours to ultimate consumers.
150,000 megawatthours of sales for resale.

The 1996-1997 data represents those public electric utilities meeting a threshold of 120,000 megawatthours ultimate consumers' sales and or resales. Approximately 500 publicly owned electric utilities are required to submit the Form EIA-412 for 2000. These major publicly owned electric utilities represent about one-fourth of all publicly owned electric utilities. Relating to the major publicly owned utilities, there were 506 respondents in 2000 compared to 493 respondents in 1999. These respondents represent over 85 percent of the sales of electricity to ultimate consumers and over 81 percent of the revenues from the sales to ultimate consumers for all publicly owned electric utilities. These electric utilities are requested, but not required, to follow the FERC Uniform System of Accounts. Detailed financial statistics on public electric utilities, Federal electric utilities, and rural electric cooperatives are published in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities.*[9]

[9] For detailed data see *Financial Statistics of Major U.S. Publicly Owned Electric Utilities,* DOE/EIA-0437/2, published annually by the Energy Information Administration (EIA).

Table 8. Composite Statement of Income for Major U.S. Investor-Owned Electric Utilities, 1996 Through 2000

(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Operating Revenue	**207,459,078**	**215,082,593**	**218,174,613**	**214,160,472**	**235,336,467**
Electric	188,900,781	195,897,868	201,970,019	197,577,518	214,706,565
Gas	17,869,394	18,662,611	15,734,812	16,033,291	19,947,581
Other Utility	688,903	522,114	469,782	549,662	682,320
Operating Expenses	**173,920,492**	**182,796,184**	**186,497,546**	**182,258,470**	**210,324,036**
Electric	156,937,816	165,443,479	171,688,890	167,266,172	191,329,362
Operation	97,206,642	104,337,106	110,758,800	108,460,803	132,662,431
Maintenance	12,049,844	12,367,646	12,485,809	12,276,436	12,184,848
Depreciation[1]	21,193,742	23,072,100	24,122,208	23,968,285	23,669,903
Taxes Other Than Income Taxes	13,569,490	13,611,714	12,867,359	12,336,492	11,882,863
Regulatory Debits (net)	683,185	615,575	–455,682	–708,435	4,794,035
Income Taxes	11,194,656	11,862,201	13,037,021	14,843,421	7,641,212
Deferred Income Tax	1,616,998	25,433	–476,064	–2,216,263	–945,053
Investment Tax Credit (Net)	–576,741	–448,296	–650,561	–1,694,568	–560,876
Gas	16,257,611	16,925,438	14,395,995	14,493,318	18,340,855
Income Taxes	223,871	584,937	667,681	633,531	314,940
Other	16,033,740	16,340,501	13,718,314	13,859,787	18,025,915
Other Utility	725,066	427,267	412,661	498,980	653,819
Income Taxes	–21,775	1,945	–3,782	–9,568	–24,057
Other	746,841	425,321	416,444	508,547	677,876
Operating Income	**33,538,586**	**32,286,409**	**31,677,067**	**31,902,002**	**25,012,430**
Electric	31,962,965	30,454,389	30,281,129	30,311,346	23,377,203
Gas	1,611,783	1,737,173	1,338,817	1,539,973	1,606,726
Other	–36,163	94,847	57,121	50,683	28,501
Other Income and Deductions	**1,614,287**	**1,813,459**	**1,111,163**	**1,665,449**	**3,609,047**
Allowance for Other Funds Used During Construction	230,791	210,208	189,183	203,702	209,948
Less Taxes	597,230	1,006,783	1,741,612	–1,813,496	176,197
Deferred Earnings (Misc.) (acct 421)	774,012	665,506	2,722,008	3,273,402	6,525,355
Less Other Income and Expenses[2]	–1,206,714	–1,953,528	58,417	3,625,151	2,950,059
Total Income Before Interest Charges	**35,152,873**	**34,099,868**	**32,788,230**	**33,567,451**	**28,621,477**
Net Interest Charges	**13,990,388**	**14,085,736**	**14,056,616**	**13,691,495**	**13,781,219**
Interest Expense	13,645,951	13,767,563	13,670,318	13,376,175	13,665,925
Less Allowance for Borrowed Funds Used During Construction	326,158	331,057	328,378	330,928	396,891
Other Charges--Net	670,597	649,300	714,675	646,248	512,185
Net Income Before Extraordinary Charges	**21,162,485**	**20,014,132**	**18,731,615**	**19,875,956**	**14,840,259**
Less Extraordinary Items After Taxes[2]	**–65,696**	**3,151,490**	**1,343,507**	**2,793,032**	**1,566,537**
Net Income	**21,228,180**	**16,862,642**	**17,388,108**	**17,082,923**	**13,273,722**
Dividends Declared - Preferred Stock	**1,248,409**	**1,005,367**	**750,305**	**686,774**	**567,982**
Earnings Available for Common Stocks	**19,979,771**	**15,857,275**	**16,637,803**	**16,396,150**	**12,705,739**
Dividends Declared - Common Stock	**16,810,054**	**17,756,067**	**17,414,045**	**18,686,752**	**16,677,092**
Additions Total Earnings	**2,193,444**	**–1,959,552**	**–198,753**	**–2,784,590**	**–3,971,353**

1 Includes amortization and depletion.
2 Other Income and Expenses and Extraordinary Items After Taxes were affected negatively by aftertax write offs, accounting adjustments, and regulatory rate decisions.

Notes: •Data for 1996 through 1999 are final; whereas data for 2000 are preliminary. •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.'' The 1997 through 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

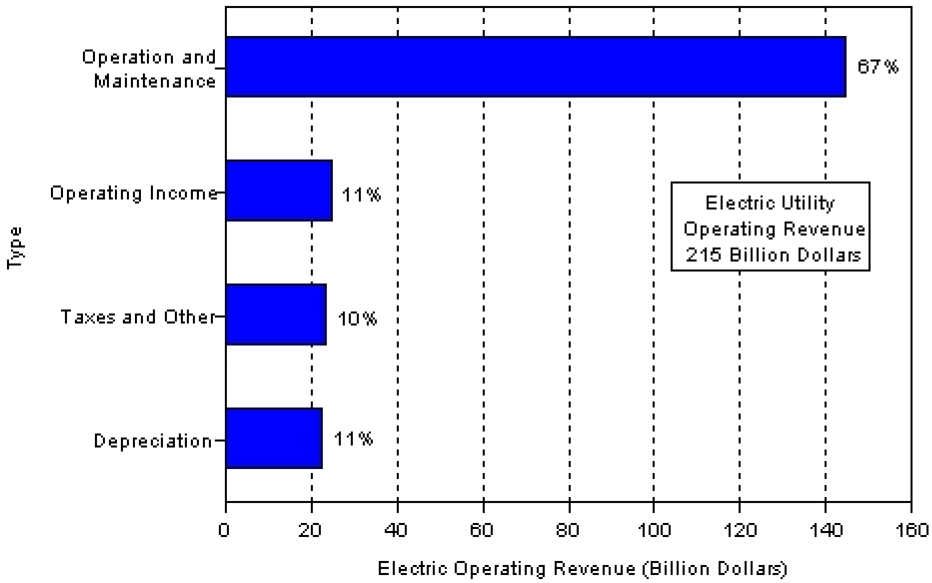
Table 9. Composite Balance Sheet for Major U.S. Investor-Owned Electric Utilities, 1996 Through 2000
(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Assets					
Utility Plant - Net	**396,437,823**	**385,258,389**	**362,387,812**	**344,111,676**	**340,897,261**
Electric Utility Plant - Net	363,853,762	351,426,794	327,646,043	310,317,423	307,284,121
Electric Utility Plant	569,968,617	579,042,425	575,651,242	567,824,719	570,319,873
Construction Work in Progress	11,395,525	11,163,637	11,886,399	12,305,936	14,766,112
Less Accumulated Depreciation	217,510,379	238,779,268	259,891,598	269,813,232	277,801,864
Nuclear Fuel - Net	5,443,854	5,218,574	4,731,088	4,265,436	3,973,662
Other Utility Plant - Net	27,140,206	28,613,021	30,010,680	29,528,818	29,639,478
Other Property and Investments	**33,119,898**	**43,247,896**	**48,853,135**	**54,546,121**	**56,992,412**
Current and Accrued Assets	**43,515,064**	**47,639,268**	**54,901,305**	**57,324,293**	**79,169,498**
Deferred Debits	**108,918,179**	**110,095,573**	**132,713,547**	**129,844,600**	**129,312,340**
Total Assets and other Debits	**581,990,963**	**586,241,128**	**598,855,799**	**585,826,690**	**606,371,510**
Capitalization and Liabilities					
Capitalization	**365,782,779**	**369,079,448**	**367,052,433**	**345,786,166**	**341,163,255**
Common Stock Equity (End of Year)	174,325,424	174,467,159	172,239,056	165,340,710	160,379,947
Common Stock	112,633,284	113,889,942	113,200,530	109,187,900	110,422,283
Retained Earnings (Adjusted)	61,692,140	60,577,217	59,038,526	56,152,810	49,957,664
Preferred Stock	18,830,248	16,080,195	14,447,351	12,061,103	9,892,794
Long-term Debt	172,627,107	178,532,093	180,366,026	168,384,353	170,890,514
Current Liabilities and Deferred Credits	**216,208,185**	**217,161,680**	**231,803,366**	**240,040,524**	**265,208,256**
Other Noncurrent Liabilities	15,309,391	17,085,609	18,027,365	19,153,475	17,536,439
Current and Accrued Liabilities	49,341,620	51,594,407	57,591,036	64,777,564	92,783,388
Deferred Credits	151,557,174	148,481,665	156,184,964	156,109,484	154,888,429
Accumulated Deferred Income Taxes	100,537,249	106,393,740	106,405,740	101,171,234	96,727,732
Accumulated Deferred Investment Tax Credit	11,491,332	10,782,506	9,731,454	8,647,413	7,389,995
Other Deferred Credits (Adjusted)	29,528,592	31,305,418	40,047,770	46,290,839	50,770,702
Total Liabilities and Other Credits	**581,990,963**	**586,241,128**	**598,855,799**	**585,826,690**	**606,371,511**

Notes: •Data for 1996 through 1999 are final; whereas data for 2000 are preliminary. •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.'' The 1997 through 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

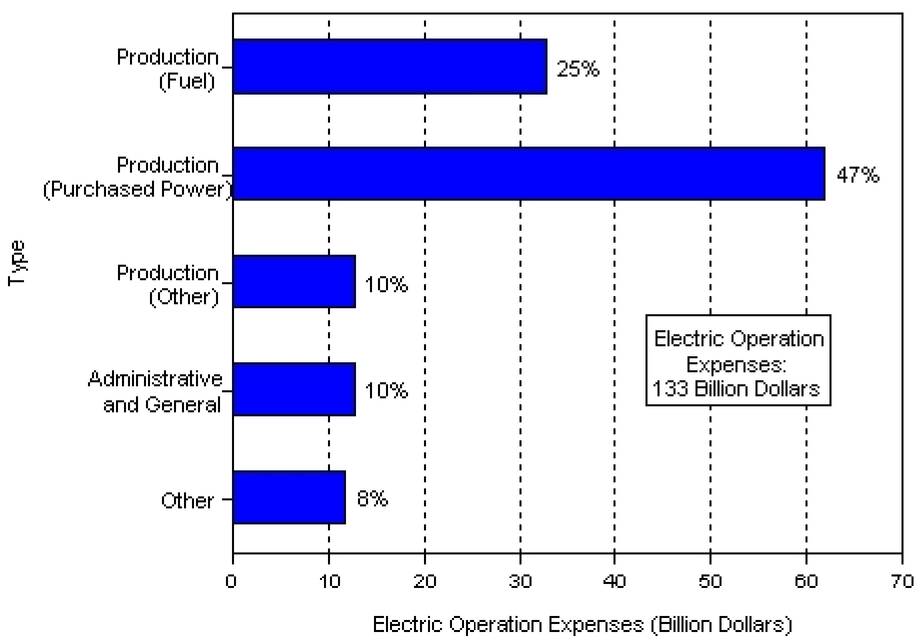
Figure 6. Allocation of the Revenue Dollar from Electric Operations for Major U.S. Investor-Owned Electric Utilities, 2000



Notes: ! Data are preliminary. ! Depreciation includes amortization and depletion. ! Totals may not equal sum of components because of independent rounding. See Table 8.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." The 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Figure 7. Electric Operation Expenses for Major U.S. Investor-Owned Electric Utilities, 2000



Notes: ! Data are preliminary. ! Other includes transmission, distribution, customer account, customer service, and sales. ! Totals may not equal sum of components because of independent rounding. See Table 11.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." The 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 10. Composite Financial Indicators for Major U.S. Investor-Owned Electric Utilities, 1996 Through 2000

Description[1]	1996	1997	1998	1999	2000
Activity					
1. Electric Fixed Asset (Net Plant) Turnover	0.52	0.56	0.62	0.64	0.70
2. Total Asset Turnover	.36	.37	.36	.37	.39
Leverage					
3. Current Assets to Current Liabilities	.88	.92	.95	.88	.85
4. Long-term Debt to Capitalization	47.19	48.37	49.14	48.70	50.09
5. Preferred Stock to Capitalization	5.15	4.36	3.94	3.49	2.90
6. Common Stock Equity to Capitalization	47.66	47.27	46.92	45.98	44.63
7. Total Debt to Total Assets[2]	31.57	32.23	R 32.04	31.10	31.18
8. Common Stock Equity to Total Assets	29.95	29.76	28.76	28.22	26.45
9. Interest Coverage Before Taxes without AFUDC	3.36	3.33	3.36	3.66	2.67
Profitability					
10. Profit Margin	10.23	7.84	7.97	7.98	5.64
11. Return on Average Common Stock Equity[3]	12.31	9.67	10.03	10.12	8.15
12. Return on Investment	3.65	2.88	2.90	2.92	2.19

[1] Indicators 1, 2, 3, and 9 are ratios. Indicators 4 through 8 and 10 through 12 are percentages.

[2] Total debt is the sum of Long-term Debt and Short-term Debt. The values for Short-term Debt included in Current and Accrued liabilities (Notes Payable) $18,179,816,000 for 2000; $13,802,174,000 for 1999; $11,531,000,000 for 1998 (revised); $10,417,018,000 for 1997; and $11,129,401,000 for 1996.

[3] The Average Common Stock Equity is the average of the beginning and ending year balances. The value for the beginning of 1996 was $172,411,278,000.

R = Revised data.

Notes: •Data for 1996 through 1999 are final; whereas data for 2000 are preliminary. •Formulas for computing the financial indicators are in Appendix A. •Indicators 4, 5, and 6 may not sum to 100 percent because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.''

Table 11. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1996 Through 2000

(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Utility Operating Revenues	**207,459,078**	**215,082,593**	**218,174,613**	**214,160,472**	**235,336,467**
Electric Utility	188,900,781	195,897,868	201,970,019	197,577,518	214,706,565
Other Utility	18,558,297	19,184,725	16,204,594	16,582,954	20,629,901
Utility Operating Expenses	**173,920,492**	**182,796,184**	**186,497,546**	**182,258,470**	**210,324,036**
Electric Utility	156,937,816	165,443,479	171,688,890	167,266,172	191,329,362
Operation	97,206,642	104,337,106	110,758,800	108,460,803	132,662,431
Production	73,436,927	80,152,500	85,956,077	83,554,665	107,351,625
Cost of Fuel	30,706,261	31,860,594	31,251,880	29,826,376	32,554,841
Purchased Power	32,987,034	37,990,963	42,611,883	43,258,418	61,968,664
Other	9,743,632	10,300,942	12,092,314	10,469,871	12,828,120
Transmission	1,503,196	1,915,174	2,197,331	2,423,452	2,698,754
Distribution	2,604,058	2,699,803	2,803,526	2,955,635	3,114,976
Customer Accounts	3,848,302	3,767,257	4,021,303	4,194,579	4,245,501
Customer Service	1,920,450	1,197,459	1,955,451	1,889,234	1,839,331
Sales	435,477	500,934	514,388	492,039	403,250
Administrative and General	13,458,234	13,383,979	13,310,724	12,951,199	13,008,993
Maintenance	12,049,844	12,367,646	12,485,809	12,276,436	12,184,848
Depreciation	21,193,742	23,072,100	24,122,208	23,968,285	22,761,233
Taxes and Other	26,487,588	25,666,627	24,322,072	22,560,647	23,720,851
Other Utility	16,982,677	17,352,705	14,808,656	14,992,298	18,994,674
Net Utility Operating Income	**33,538,586**	**32,286,409**	**31,677,067**	**31,902,002**	**25,012,430**

Notes: •Data for 1996 through 1999 are final; whereas data for 2000 are preliminary. •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.'' The 1997 through 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 12. Revenue and Expense Percentages for Major U.S. Investor-Owned Electric Utilities, 1996 Through 2000

Description	1996	1997	1998	1999	2000
Utility Operating Revenues	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Electric Utility	91.1	91.1	92.6	92.3	91.2
Other Utility	8.9	8.9	7.4	7.7	8.8
Utility Operating Expenses	**83.8**	**85.0**	**85.5**	**85.1**	**89.4**
Electric Utility	75.6	76.9	78.7	78.1	81.3
Operation	46.9	48.5	50.8	50.6	56.4
Production	35.4	37.3	39.4	39.0	45.6
Cost of Fuel	14.8	14.8	14.3	13.9	13.8
Purchased Power	15.9	17.7	19.5	20.2	26.3
Other	4.7	4.8	5.5	4.9	5.5
Transmission	.7	.9	1.0	1.1	1.1
Distribution	1.3	1.3	1.3	1.4	1.3
Customer Accounts	1.9	1.8	1.8	2.0	1.8
Customer Service	.9	.9	.9	.9	.8
Sales	.2	.2	.2	.2	.2
Administrative and General	6.5	6.2	6.1	6.0	5.5
Maintenance	5.8	5.8	5.7	5.7	5.2
Depreciation	10.2	10.7	11.1	11.2	9.7
Taxes and Other	12.8	11.9	11.1	10.5	10.1
Other Utility	8.2	8.1	6.8	7.0	8.1
Net Utility Operating Income	**16.2**	**15.0**	**14.5**	**14.9**	**10.6**

Notes: •Data for 1996 through 1999 are final; whereas data for 2000 are preliminary. •Percents in this table are percentage of utility operating revenues. •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.'' The 1997 through 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 13. Average Operating Expenses for Major U.S. Investor-Owned Electric Utilities 1996 Through 2000

(Mills per Kilowatthour)

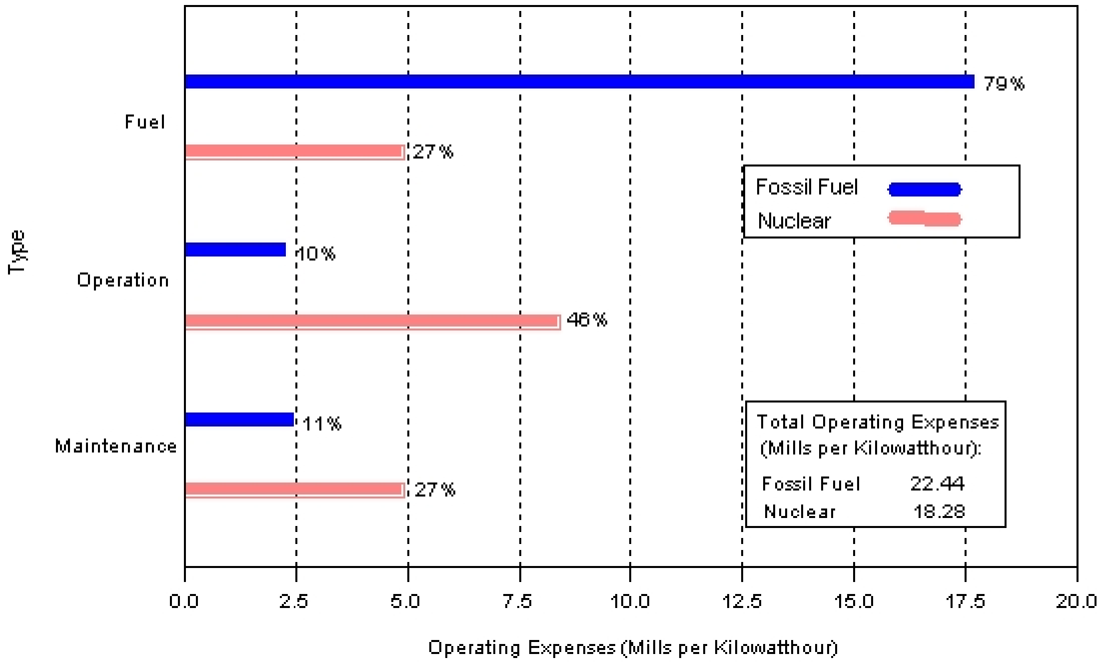
	1996	1997	1998	1999	2000
			Operation		
Nuclear	9.47	11.02	9.98	8.93	8.41
Fossil Steam	2.25	2.22	2.17	2.21	2.31
Hydroelectric[1]	3.87	3.29	3.85	4.17	4.74
Gas Turbine and Small Scale[2]	5.08	4.43	3.85	5.16	4.57
			Maintenance		
Nuclear	5.68	6.90	5.79	5.13	4.93
Fossil Steam	2.49	2.43	2.41	2.38	2.45
Hydroelectric[1]	2.08	2.49	2.00	2.60	2.99
Gas Turbine and Small Scale[2]	4.98	3.43	3.43	4.80	3.50
			Fuel		
Nuclear	5.50	5.42	5.39	5.17	4.95
Fossil Steam	16.51	16.80	15.94	15.62	17.69
Hydroelectric[1]	--	--	--	--	--
Gas Turbine and Small Scale[2]	30.58	24.94	23.02	28.72	39.19
			Total[3]		
Nuclear	20.65	23.33	21.16	19.23	18.28
Fossil Steam	21.25	21.45	20.52	20.22	22.44
Hydroelectric[1]	5.94	5.79	5.86	6.77	7.73
Gas Turbine and Small Scale[2]	40.64	32.80	30.30	38.68	47.26

1 Includes Pumped Storage.
2 Includes gas turbine, internal combustion, photovoltaic, and wind plants.
3 Totals may not equal sum of components because of independent rounding.

Notes: •Data for 1996 through 1999 are final; whereas data for 2000 are preliminary. •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 1 cent).

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.'' The 1997 through 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Figure 8. Average Operating Expenses of Fossil-Fueled and Nuclear Steam-Electric Plants for Major U.S. Investor-Owned Electric Utilities, 2000



Notes: ! Data are preliminary. ! Totals may not equal sum of components because of independent rounding. See Table 13.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." The 2000 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 14. Composite Statement of Income for Major U.S. Publicly Owned Generator Electric Utilities, 1996 Through 2000

(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Operating Revenue - Electric	**24,207,226**	**25,397,219**	**26,154,732**	**26,766,900**	**31,842,783**
Operating Expenses - Electric	**19,083,980**	**20,425,111**	**20,880,194**	**21,273,860**	**26,244,346**
Operation Excluding Fuel	**11,270,829**	**11,819,689**	**11,949,846**	**11,992,638**	**14,737,482**
Fuel	2,497,215	3,097,486	3,169,838	3,393,281	4,837,071
Maintenance	1,637,828	1,608,781	1,631,484	1,686,120	1,814,899
Depreciation and Amortization	3,015,665	3,239,454	3,458,805	3,504,605	3,919,211
Taxes and Tax Equivalents	662,443	659,702	670,221	697,215	935,682
Operating Income - Electric	**5,123,246**	**4,972,108**	**5,274,538**	**5,493,040**	**5,598,437**
Other Income and Deductions	**1,237,173**	**1,351,939**	**1,352,927**	**937,809**	**1,617,776**
Income from Electric Plant Leased to Others	25,914	17,953	17,528	11,341	28,640
Allowance for Funds Used During Construction	6,660	4,320	5,208	5,802	4,568
Other Income Net	1,440,435	1,478,106	1,506,383	1,358,155	1,850,151
Less Other Electric Deductions	235,836	148,440	176,192	437,489	265,583
Total Income Before Interest Charges	**6,360,419**	**6,324,047**	**6,627,465**	**6,430,849**	**7,216,213**
Net Interest Charges	**4,634,548**	**4,681,830**	**4,574,910**	**4,467,834**	**4,796,820**
Interest Expenses	4,155,829	4,119,946	3,984,982	3,810,418	4,071,856
Other Income Deductions	478,719	561,883	589,928	657,416	724,964
Net Income Before Extraordinary Charges	**1,725,871**	**1,642,217**	**2,052,555**	**1,963,015**	**2,419,393**
Less **Extraordinary Items**	**2,304**	**13,258**	**120,722**	**186,344**	**174,144**
Net Income	**1,723,567**	**1,628,959**	**1,931,833**	**1,776,671**	**2,245,249**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 225 for 2000, 226 for 1999, 228 for 1998, 245 for 1997, and 231 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

Table 15. Composite Balance Sheet for Major U.S. Publicly Owned Generator Electric Utilities, 1996 Through 2000

(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**64,159,411**	**63,939,798**	**62,854,031**	**63,156,349**	**67,585,195**
Electric Utility Plant Inc Nuclear Fuel	97,433,005	100,346,538	101,775,589	105,804,369	111,636,531
Accumulated Provision for Depreciation and Amortization	33,273,595	36,406,740	38,921,558	42,648,020	44,051,336
Other Property and Investments	**19,674,912**	**20,156,959**	**19,969,531**	**21,456,288**	**23,002,240**
Current and Accrued Assets	**16,521,745**	**17,148,023**	**17,245,072**	**17,963,595**	**23,035,913**
Deferred Debits	**13,520,724**	**13,619,929**	**13,381,374**	**13,691,266**	**13,915,618**
Total Assets and Other Debits	**113,876,791**	**114,864,710**	**113,450,008**	**116,267,499**	**127,538,966**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**27,472,346**	**29,111,977**	**30,001,524**	**31,865,580**	**34,221,924**
Long-Term Debt	**73,950,415**	**73,035,157**	**70,145,214**	**69,554,404**	**75,735,131**
Other Noncurrent Liabilities	**766,093**	**593,007**	**608,049**	**618,451**	**681,553**
Current and Accrued Liabilities	**8,167,668**	**8,554,223**	**8,714,034**	**9,012,772**	**10,623,168**
Deferred Credits	**3,520,270**	**3,570,346**	**3,981,187**	**5,216,292**	**6,277,190**
Total Liabilities and Other Credits	**113,876,791**	**114,864,710**	**113,450,008**	**116,267,499**	**127,538,966**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 225 for 2000, 226 for 1999, 228 for 1998, 245 for 1997, and 231 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

Table 16. Composite Financial Indicators for Major U.S. Publicly Owned Generator Electric Utilities, 1996 Through 2000

Description	1996	1997	1998	1999	2000
Electric Utility Plant per Dollar of Revenue	4.0	4.0	3.9	4.0	3.5
Current Assets to Current Liabilities	2.0	2.0	2.0	2.0	2.2
Electric Utility Plant as a Percent of Total Assets	85.6	87.4	89.7	91.0	87.5
Net Electric Utility Plant as a Percent of Total Assets	56.3	55.7	55.4	54.3	53.0
Debt as a Percent of Total Liabilities	72.1	71.0	69.5	67.6	67.7
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	34.2	36.3	38.2	40.3	39.5
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	63.6	65.1	64.0	63.8	67.2
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	11.9	12.1	12.4	12.1	10.8
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.7	2.6	2.6	2.6	2.9
Interest Expenses as a Percent of Electric Operating Revenues	17.2	16.2	15.2	14.2	12.8
Net Income as a Percent of Electric Operating Revenues	7.1	6.4	7.4	6.6	7.1
Purchase Power Cents Per Kilowatthour	3.8	3.2	3.2	3.2	3.7
Generated Cents Per Kilowatthour	1.5	1.7	1.7	1.7	2.0
Total Power Supply Per Kilowatthour Sold	2.4	2.4	2.4	2.3	2.9

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 225 for 2000, 226 for 1999, 228 for 1998, 245 for 1997, and 231 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

Table 17. Revenue and Expense Statistics for Major U.S. Publicly Owned Generator Electric Utilities, 1996 Through 2000
(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Operating Revenue - Electric	**24,207,226**	**25,397,219**	**26,154,732**	**26,766,900**	**31,842,783**
Operating Expenses - Electric	**19,083,980**	**20,425,111**	**20,880,194**	**21,273,860**	**26,244,346**
Operation Including Fuel	13,768,044	14,917,174	15,119,684	15,385,920	19,574,554
Production	11,097,895	11,481,328	11,608,407	11,922,977	15,742,217
Transmission	349,114	725,471	772,598	732,289	780,976
Distribution	475,506	538,320	603,199	515,985	573,548
Customer Accounts	365,277	390,231	390,430	414,545	506,983
Customer Service	103,390	133,257	126,813	160,158	210,618
Sales	17,528	46,181	50,804	49,112	65,522
Administrative and General	1,359,334	1,602,386	1,567,434	1,590,854	1,694,689
Maintenance	1,637,828	1,608,781	1,631,484	1,686,120	1,814,899
Depreciation and Amortization	2,933,594	3,080,165	3,240,505	3,241,178	3,441,966
Taxes and Tax Equivalents	662,443	659,702	670,221	697,215	935,682
Income from Electric Utility Operations	**5,123,246**	**4,972,108**	**5,274,538**	**5,493,040**	**5,598,437**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 225 for 2000, 226 for 1999, 228 for 1998, 245 for 1997, and 231 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

Table 18. Composite Statement of Income for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1996 Through 2000
(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Operating Revenue - Electric	**8,581,642**	**8,585,879**	**8,790,223**	**9,354,023**	**9,904,214**
Operating Expenses - Electric	**8,122,815**	**8,033,488**	**8,245,380**	**8,737,044**	**9,354,927**
Operation Excluding Fuel	**7,358,592**	**7,117,155**	**7,437,112**	**7,873,718**	**8,423,596**
Fuel	—	—	–540	–141	448
Maintenance	244,115	337,769	263,356	272,299	286,077
Depreciation and Amortization	313,720	353,948	330,433	368,552	393,714
Taxes and Tax Equivalents	206,389	224,617	215,019	222,615	251,093
Operating Income - Electric	**458,827**	**552,391**	**544,843**	**616,979**	**549,287**
Other Income and Deductions	**153,864**	**102,307**	**130,282**	**137,738**	**162,710**
Income from Electric Plant Leased to Others	12,569	12,989	4,248	4,465	4,124
Allowance for Funds Used During Construction	70	311	192	197	142
Other Income Net	207,859	165,655	185,272	205,362	241,550
Less Other Electric Deductions	66,634	76,649	59,430	72,285	83,106
Total Income Before Interest Charges	**612,691**	**654,698**	**675,126**	**754,717**	**711,997**
Net Interest Charges	**148,146**	**148,297**	**152,428**	**155,798**	**155,217**
Interest Expenses	99,768	107,351	102,729	107,842	113,642
Other Income Deductions	48,378	40,947	49,699	47,956	41,575
Net Income Before Extraordinary Charges	**464,545**	**506,400**	**522,698**	**598,919**	**556,780**
Less **Extraordinary Items**	**4,066**	**–3,050**	**–9,842**	**–7,038**	**9,158**
Net Income	**460,479**	**509,451**	**532,539**	**605,956**	**547,623**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 281 for 2000, 267 for 1999, 259 for 1998, 299 for 1997, and 284 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

Table 19. Composite Balance Sheet for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1996 Through 2000
(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**6,259,916**	**8,447,445**	**6,871,025**	**7,437,385**	**8,094,102**
Electric Utility Plant Inc Nuclear Fuel	9,925,097	12,831,306	10,963,297	11,952,629	12,981,988
Accumulated Provision for Depreciation and Amortization	3,665,181	4,383,861	4,092,272	4,515,244	4,887,886
Other Property and Investments	**1,885,263**	**2,067,375**	**2,123,546**	**2,328,518**	**2,612,262**
Current and Accrued Assets	**2,701,644**	**2,925,365**	**2,857,991**	**3,180,710**	**3,493,763**
Deferred Debits	**407,965**	**465,338**	**358,010**	**313,893**	**424,177**
Total Assets and Other Debits	**11,254,787**	**13,905,523**	**12,210,573**	**13,260,506**	**14,624,304**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**7,150,022**	**8,543,320**	**7,871,482**	**8,808,622**	**9,534,206**
Long-Term Debt	**2,593,375**	**3,808,733**	**2,676,839**	**2,716,531**	**3,108,926**
Other Noncurrent Liabilities	**17,991**	**14,808**	**137,989**	**128,768**	**135,327**
Current and Accrued Liabilities	**1,263,814**	**1,259,125**	**1,317,256**	**1,407,290**	**1,659,474**
Deferred Credits	**229,585**	**279,537**	**207,007**	**199,295**	**186,370**
Total Liabilities and Other Credits	**11,254,787**	**13,905,523**	**12,210,573**	**13,260,506**	**14,624,304**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 281 for 2000, 267 for 1999, 259 for 1998, 299 for 1997, and 284 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

Table 20. Composite Financial Indicators for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1996 Through 2000

Description	1996	1997	1998	1999	2000
Electric Utility Plant per Dollar of Revenue	1.2	1.5	1.2	1.3	1.3
Current Assets to Current Liabilities	2.1	2.3	2.2	2.3	2.1
Electric Utility Plant as a Percent of Total Assets	88.2	92.3	89.8	90.1	88.8
Net Electric Utility Plant as a Percent of Total Assets	55.6	60.7	56.3	56.1	55.3
Debt as a Percent of Total Liabilities	34.3	36.4	32.7	31.1	32.6
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	36.9	34.2	37.3	37.8	37.7
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	88.6	86.8	87.6	87.1	87.9
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	3.6	4.1	3.7	3.9	3.9
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.4	2.6	2.4	2.4	2.5
Interest Expenses as a Percent of Electric Operating Revenues	1.2	1.3	1.2	1.2	1.1
Net Income as a Percent of Electric Operating Revenues	5.4	5.9	6.1	6.5	5.5
Purchase Power Cents Per Kilowatthour	4.0	4.0	4.1	4.1	4.2

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 281 for 2000, 267 for 1999, 259 for 1998, 299 for 1997, and 284 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

Table 21. Revenue and Expense Statistics for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1996 Through 2000
(Thousand Dollars)

Description	1996	1997	1998	1999	2000
Operating Revenue - Electric	**8,581,642**	**8,585,879**	**8,790,223**	**9,354,023**	**9,904,214**
Operating Expenses - Electric	**8,122,815**	**8,033,488**	**8,245,380**	**8,737,044**	**9,354,927**
Operation Including Fuel	7,358,592	7,117,155	7,436,572	7,873,577	8,424,044
Production	6,577,447	6,239,721	6,660,705	7,015,036	7,485,562
Transmission	50,446	56,969	44,443	47,501	63,900
Distribution	234,893	303,983	229,609	261,223	279,996
Customer Accounts	141,458	139,156	129,856	142,717	154,555
Customer Service	18,229	16,379	20,862	22,182	22,325
Sales	11,616	12,897	8,868	13,785	16,039
Administrative and General	324,503	348,051	342,228	371,133	401,667
Maintenance	244,115	337,769	263,356	272,299	286,077
Depreciation and Amortization	305,612	350,862	326,863	364,603	389,181
Taxes and Tax Equivalents	206,389	224,617	215,019	222,615	251,093
Income from Electric Utility Operations	**458,827**	**552,391**	**544,843**	**616,979**	**549,287**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1996-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 281 for 2000, 267 for 1999, 259 for 1998, 299 for 1997, and 284 for 1996.

Source: Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities.''

U.S. Electric Utility Environmental Statistics

When fossil fuels are burned in the production of electricity, a variety of gases and particulates are formed. If these gases and particulates are not captured by some pollution control equipment, they are released into the atmosphere. This chapter provides a brief summary of the gaseous emissions from U.S. electric utilities and the methods employed to reduce or eliminate their release into the atmosphere.

Background

Among the gases emitted during the burning of fossil fuels are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). Coal-fired generating units produce more SO_2 and NO_x than other fossil-fuel units for two reasons. First, because coal generally contains more sulfur than other fossil fuels, it creates more SO_2 when burned. Second, there are more emissions from coal-fired plants because more coal-fired capacity than other fossil-fueled capacity is in use.

Sulfur is an element that is present in almost all coal, although some kinds of coal contain more sulfur than others depending on the geographic location of the coal mine and the type of coal being mined. Western coal has less sulfur than eastern coal. More than one-half of the coal mined in the West is subbituminous coal that is low in sulfur content (about 0.5 percent) and contains approximately 9,000 Btu per pound. Bituminous eastern coal can exceed both a 5-percent sulfur content and a heat content of 12,000 Btu per pound. The average percent of sulfur contained in coal ranges from 0.3 percent in the West to approximately 2.5 percent in the East. During combustion, the sulfur combines with the oxygen in the air to form SO_2. As the SO_2 mixes further with oxygen and trace substances in the air, a variety of sulfate compounds emerges. How these transformations take place, and in what proportions, is a subject of vigorous research. The behavior of SO_2 emissions depends partly on the type of coal used and how it is burned. In addition, the presence of light, moisture, and other pollutants in the atmosphere may also be important in triggering the complex changes that SO_2 emissions undergo. To a lesser degree, sulfur is also contained in petroleum and varies according to the type of petroleum (for example, light oil, heavy oil, etc.). Petroleum burned at utility power plants ranges from containing almost no sulfur to about 3.5 percent sulfur. The weighted average percent of sulfur contained in petroleum consumed by utility plants ranges from about .5 percent in western plants to about 1.4 percent for plants in New England. The amount of sulfur contained in natural gas is insignificant.

Nitrogen is a colorless, odorless gas that makes up about 78 percent of the atmosphere. Nitrogen in the atmosphere during the combustion process (burning of fuels at the plant) combines with oxygen and water to form several NO_x compounds. Also, a small amount of nitrogen in the coal is converted to NO_x. The most important is nitrogen dioxide, one of the compounds that gives photochemical smog its characteristic yellowish-brown color. Only about 10 percent of the nitrogen compounds in the air are the result of human activity. The rest are formed by natural processes, such as the decay of organic matter. However, since the human-made 10 percent is emitted mostly in industrial urban areas, concentration there can become high enough to cause concern.

SO_2 and NO_x are called precursors to acid deposition, because, under the right set of conditions, they react with other chemicals in the atmosphere to form sulfuric acid and nitric acid, respectively. These two acids do not accumulate in the atmosphere, but are absorbed by rain droplets, thus cleansing the atmosphere but discharging the acid onto the earth in the form of "acid rain." In addition, sulfuric acid may form microscopic droplets that can be deposited directly onto the ground. This form of deposition, as well as the direct capture of SO_2 by vegetation, is referred to as dry deposition.

CO_2 is a colorless, odorless, nontoxic gas formed by the combustion of carbon and carbon compounds found in coal, petroleum, and gas. Currently, the only way to limit the emission of CO_2 when burning fossil fuels is extremely expensive. CO_2 is normally removed from the atmosphere by green plants and absorbed by the ocean. The increased use of fossil fuels in recent years, as well as extensive deforestation, has caused a buildup of CO_2 in the atmosphere. This increase of CO_2 causes the atmosphere to absorb infrared radiation reflected from the earth that would otherwise have been dissipated into space. This phenomenon could increase average global temperature. It is called the "greenhouse" effect because it is similar to the trapping of the sun energy in a greenhouse. These potential increases in temperatures are of concern because they could cause significant climatic changes, shifts in agricultural zones, and partial melting of the polar ice caps resulting in flooding of coastal areas. However, significant uncertainties exist regarding global warming, and no conclusions can be drawn regarding future warming based on past temperature records.

Efforts are underway to determine what methods can be employed to reduce or eliminate the release of CO_2 from power plants. Tail gas cleanup (CO_2 scrubbing) is currently the only technological option. This option would require the adaptation by the electric utility industry of acid gas removal technologies used by the petroleum and petrochemical industries. Because of the potential expense involved and the uncertainty concerning the impacts of emissions from the gas, no emission standards or required reductions exist.

Additionally, the Department of Energy is developing clean coal technologies (such as pressurized fluidized-bed combustion) for new plants and repowering applications. Due to the increased conversion efficiencies of these technologies, CO_2 emissions are reduced.

Emission Standards

To respond to concerns about emissions of SO_2 and NO_x as well as several other air pollutants, Congress passed the Clean Air Act (CAA) in 1963. It was not until 1970, however, that the Environmental Protection Agency was empowered to set enforceable air quality standards. In 1971, this Agency established New Source Performance Standards (NSPS) that required coal-fired utility boilers built after August 17, 1971, to emit no more than 1.2 pounds of SO_2 per million Btu of heat input. Requirements for NO_x were more complex, with allowable limits ranging from 0.2 pounds per million Btu to 0.8 pounds per million Btu, depending on the type of fuel burned and the combustion device used.

In 1977, Congress amended the CAA to require States to set limits on existing sources in regions not attaining goals established in the Act. In 1979, the Environmental Protection Agency established the Revised New Source Performance Standards (RNSPS). The new standards retain the 1971 NSPS of 1.2 pounds of SO_2 per million Btu of heat input, but require SO_2 emissions from all new or modified (post 1978) boilers to be reduced by at least 90 percent unless 90-percent removal reduces emissions to less than 0.6 pounds per million Btu. If emissions fall below that level, reductions between 70 and 90 percent are permitted, depending on the sulfur content of the coal. RNSPS for NO_x are complex and, as with NSPS, set limits varying from 0.2 to 0.8 pounds per million Btu, depending on the type of fuel burned and combustion device used. RNSPS for NO_x differ from NSPS in the number of categories of combustion into which they are divided.

The primary goals of the Clean Air Act Amendments (CAAA) of 1990 that affect generators of electricity are a 10-million-ton reduction in SO_2 emissions and a 2-million-ton reduction in NO_x emissions from 1980 levels. The reduction in SO_2 is to occur in two phases that begin in 1995 and 2000, respectively. The CAAA established an innovative marketable emission allowance program. It also contains a list of the allowances to be issued in Phase 1, and the Environmental Protection Agency published a preliminary list of Phase 2 allowances in June 1992.

Emission Reductions

Sulfur Dioxide. One method available to reduce the SO_2 emitted when burning coal is to switch to a coal that has a lower sulfur content. Emissions of sulfur dioxide may also be reduced by using less polluting fuels, particularly gas. Another approach is to install equipment designed to remove SO_2 from the gas (flue gas) released through the flues of the plant. Additional methods for reducing emissions of SO_2, which include converting boilers to the fluidized-bed combustion process and employing the technology of integrated-gasification combined cycle, are currently under study and not in extensive use.

Nitrogen Oxides. Formation of NO_x is less dependent on what type of fuel is burned than on how the fuel is burned. Apart from the nitrogen content of the fuel, the extent of nitric-oxide formation depends primarily on the combustion temperature. NO_x emissions can be reduced by low excess-air firing; low-combustion temperatures; use of low-nitrogen fuels (such as natural gas and light distillate oil); staged combustion in which localized fuel-rich conditions are created where both thermal and fuel NO_x are minimized; and use of low- NO_x burners and fluidized-bed combustion.

Environmental Equipment

While not the only kind of environmental equipment installed at power plants, flue gas desulfurization units, particulate collectors, and cooling towers are the most significant. In a flue gas desulfurization unit (scrubber), the gases resulting from combustion are passed through tanks containing a material that captures and neutralizes the SO_2. Particulate matter is most frequently removed from the combustion gases by either filtering (a series of filter bags that trap the ash and dust much as a household vacuum cleaner does) in a baghouse or with an electrostatic precipitator. In the latter, the particulates are given an electric charge and collected. Particulate collection is mainly centered on coal combustion because of the large percentage of ash that coal contains. Petroleum has very little ash, and natural gas has practically none.

For a fossil-fueled steam-electric generating unit, about two-thirds of the heat produced by burning the fuel is released to the environment, and only about one-third is used to produce electricity. Most waste heat (contained in the cooling water) is dissipated into a body of water, such as a river, lake, or bay. Cooling towers are installed where there is insufficient cooling water and where the waste heat discharged into the cooling water affects plants or marine life. A cooling tower is a structure for transferring heat in the water to the atmosphere. The most common type is the wet tower, also called the evaporative tower. In a wet tower, cooling is caused mainly by evaporation of the water and partly by direct-heat transfer.

Environmental equipment can represent a significant part of the cost of a power plant. This cost includes the initial capital cost of installation and the recurring operation and maintenance (O&M) costs. Capital costs are given as a cost per kilowatt of installed nameplate capacity.

Data Sources

Estimates are provided in the following tables for SO_2, NO_x, and CO_2 emissions from fossil-fueled steam-electric generating units. The methodology for computing emission estimates is described in Appendix A. Emissions of SO_2 and NO_x have been revised from the updated Air Pollutant Emissions Factors (AP-42 5th edition, through supplement E) of the Environment Protection Agency on July 1999. Emissions of CO_2 have been revised from the *Emissions of Greenhouse Gases in the United States 1998*, November 1999. Additional detailed information on emissions from electric utilities can be obtained in Chapter 6 of the *Annual Energy Outlook.*[10] Also presented in the following tables are the number and capacity of fossil-fueled steam-electric generators with environmental equipment (scrubbers, particulate collectors, and cooling towers). Because power plants can have more than one type of environmental equipment, the generators at these plants can be included in more than one category. Also, not all utility plants have environmental equipment. Data regarding the quality of fossil fuels used to produce electricity by electric utilities, including heat, sulfur, and ash content, are also provided in the following tables. Lastly, average flue gas desulfurization costs (that is, operation and maintenance costs per kilowatthour of generation and installation costs per kilowatt of nameplate capacity) are presented.

These estimates were either derived or obtained directly from the Form EIA-767, "Steam-Electric Plant Operation and Design Report." This form is a restricted-universe census used to collect boiler-specific data from over 800 U.S. electric utility power plants with organic or nuclear-fueled steam-electric nameplate capacity of 10 or more megawatts operated by more than 300 electric utilities. The entire form, including data on environmental equipment, is filed by about 700 power plants with a nameplate capacity of 100 or more megawatts. Information on power plants with a nameplate capacity between 10 and 100 megawatts is submitted only for fuel consumption and flue gas desulfurization equipment. There are 67 nuclear power plants in the Form EIA-767 respondent universe.

[10] Energy Information Administration, *Annual Energy Outlook 2002* DOE/EIA-0383(02)(Washington, DC, 2001).

Table 22. Number and Capacity of Fossil-Fueled Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment, 1996 Through 2000

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1996	182	85,842	1,134	352,154
1997	183	86,605	1,133	352,068
1998	186	87,783	1,130	351,790
1999	192	89,666	1,148	353,480
2000	192	89,675	1,141	352,727
	Cooling Towers		**Total[2]**	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1996	477	166,749	1,299	377,144
1997	480	166,886	1,301	377,195
1998	474	166,896	1,294	377,117
1999	505	175,520	1,343	387,192
2000	505	175,520	1,336	386,438

1 Nameplate capacity.
2 Components are not additive since some generators are included in more than one category and not all units have environmental equipment.

Notes: •Data for 2000 are final pending approval by the Environmental Protection Agency. Data for prior years are final. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. •Historical data have been revised to reflect additional data reported by respondents.

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

Table 23. Number and Capacity of Coal-Fired Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment by Census Division and State, 2000

Census Division State	Generating Units[1]		Scrubbers		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**14**	**2,373**	**0**	**0**	**14**	**2,373**	**0**	**0**
Connecticut	0	0	0	0	0	0	0	0
Maine	0	0	0	0	0	0	0	0
Massachusetts	9	1,764	0	0	9	1,764	0	0
New Hampshire	5	609	0	0	5	609	0	0
Rhode Island	0	0	0	0	0	0	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	**87**	**26,264**	**16**	**7,112**	**85**	**24,417**	**18**	**13,213**
New Jersey	6	1,685	1	163	6	1,685	0	0
New York	25	3,721	2	810	25	3,721	0	0
Pennsylvania	56	20,858	13	6,139	54	19,011	18	13,213
East North Central	**294**	**81,915**	**26**	**12,043**	**291**	**81,011**	**44**	**21,393**
Illinois	53	16,924	3	821	53	16,924	2	562
Indiana	69	21,105	14	5,964	67	21,013	25	9,487
Michigan	50	12,936	0	0	49	12,124	3	1,010
Ohio	85	24,047	7	5,097	85	24,047	11	8,854
Wisconsin	37	6,903	2	160	37	6,903	3	1,479
West North Central	**134**	**37,847**	**24**	**10,890**	**130**	**35,433**	**42**	**14,284**
Iowa	31	6,307	1	176	30	5,709	7	2,278
Kansas	14	5,385	7	3,920	14	5,385	8	3,258
Minnesota	24	6,917	8	3,333	21	5,099	12	5,604
Missouri	38	11,448	2	455	38	11,448	7	789
Nebraska	14	3,127	0	0	14	3,127	4	430
North Dakota	12	4,207	6	3,007	12	4,207	4	1,925
South Dakota	1	456	0	0	1	456	0	0
South Atlantic	**215**	**70,945**	**24**	**12,393**	**215**	**70,945**	**66**	**37,648**
Delaware	6	1,034	0	0	6	1,034	1	442
District of Columbia	0	0	0	0	0	0	0	0
Florida	28	11,342	9	4,971	28	11,342	12	6,757
Georgia	36	14,445	1	123	36	14,445	12	9,774
Maryland	15	4,943	0	0	15	4,943	2	1,370
North Carolina	45	12,494	0	0	45	12,494	6	3,126
South Carolina	26	6,333	6	2,509	26	6,333	15	4,795
Virginia	26	5,397	2	848	26	5,397	5	1,561
West Virginia	33	14,958	6	3,942	33	14,958	13	9,822
East South Central	**138**	**42,517**	**29**	**12,307**	**135**	**40,578**	**30**	**14,669**
Alabama	41	14,362	4	1,597	39	12,586	6	4,376
Kentucky	54	15,985	21	7,710	53	15,822	21	9,394
Mississippi	6	2,150	2	400	6	2,150	3	900
Tennessee	37	10,020	2	2,600	37	10,020	0	0
West South Central	**59**	**33,713**	**16**	**10,571**	**59**	**33,713**	**32**	**17,262**
Arkansas	5	3,958	0	0	5	3,958	4	3,400
Louisiana	8	3,799	1	721	8	3,799	6	2,681
Oklahoma	10	5,210	1	520	10	5,210	8	4,072
Texas	36	20,746	14	9,330	36	20,746	14	7,109
Mountain	**88**	**30,712**	**57**	**24,360**	**88**	**30,712**	**75**	**26,165**
Arizona	14	5,749	12	5,287	14	5,749	12	5,347
Colorado	26	4,984	9	2,648	26	4,984	23	4,480
Idaho	0	0	0	0	0	0	0	0
Montana	5	2,518	4	2,327	5	2,518	4	2,327
Nevada	8	2,769	5	879	8	2,769	7	1,951
New Mexico	10	4,375	10	4,375	10	4,375	5	2,105
Utah	10	4,461	7	3,826	10	4,461	10	4,461
Wyoming	15	5,856	10	5,018	15	5,856	14	5,494
Pacific Contiguous	**3**	**2,055**	**0**	**0**	**3**	**2,055**	**2**	**1,460**
California	0	0	0	0	0	0	0	0
Oregon	1	595	0	0	1	595	0	0
Washington	2	1,460	0	0	2	1,460	2	1,460
Pacific Noncontiguous	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Alaska	0	0	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0	0	0
U.S. Total	**1,032**	**328,341**	**192**	**89,675**	**1,020**	**321,236**	**309**	**146,093**

[1] Components are not additive since some generators are included in more than one category and not all units have environmental equipment.
[2] Nameplate capacity.
Notes: •Data for 2000 are final pending final approval by the Environmental Protection Agency. •Totals may not equal sum of components because of independent rounding. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts.
Source: Energy Information Administration, Form EIA-767, ''Steam-Electric Plant Operation and Design Report.''

Table 24. Number and Capacity of Petroleum and Gas-Fired Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment by Census Division and State, 2000

Census Division State	Generating Units[1]		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**29**	**6,570**	**27**	**6,060**	**2**	**510**
Connecticut	12	2,167	11	1,752	1	415
Maine	7	953	7	953	0	0
Massachusetts	9	3,037	8	2,942	1	95
New Hampshire	1	414	1	414	0	0
Rhode Island	0	0	0	0	0	0
Vermont	0	0	0	0	0	0
Middle Atlantic	**32**	**10,476**	**30**	**8,775**	**3**	**1,877**
New Jersey	3	491	3	491	1	176
New York	18	6,635	18	6,635	0	0
Pennsylvania	11	3,351	9	1,650	2	1,701
East North Central	**14**	**2,702**	**10**	**1,158**	**4**	**1,544**
Illinois	1	210	0	0	1	210
Indiana	1	113	1	113	0	0
Michigan	8	2,013	6	782	2	1,231
Ohio	2	217	1	114	1	104
Wisconsin	2	150	2	150	0	0
West North Central	**21**	**1,767**	**6**	**343**	**15**	**1,425**
Iowa	1	19	1	19	0	0
Kansas	15	1,526	3	161	12	1,364
Minnesota	2	163	2	163	0	0
Missouri	3	61	0	0	3	61
Nebraska	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0
South Atlantic	**49**	**15,278**	**36**	**12,029**	**17**	**4,425**
Delaware	4	597	4	597	2	132
District of Columbia	2	580	0	0	2	580
Florida	31	9,975	22	8,625	9	1,351
Georgia	2	92	2	92	0	0
Maryland	6	2,131	4	813	3	1,480
North Carolina	0	0	0	0	0	0
South Carolina	0	0	0	0	0	0
Virginia	4	1,902	4	1,902	1	882
West Virginia	0	0	0	0	0	0
East South Central	**3**	**206**	**0**	**0**	**3**	**206**
Alabama	0	0	0	0	0	0
Kentucky	0	0	0	0	0	0
Mississippi	3	206	0	0	3	206
Tennessee	0	0	0	0	0	0
West South Central	**94**	**14,484**	**4**	**2,258**	**92**	**13,325**
Arkansas	6	546	0	0	6	546
Louisiana	14	2,433	2	1,184	13	1,841
Oklahoma	19	4,350	1	567	18	3,783
Texas	55	7,155	1	507	55	7,155
Mountain	**35**	**3,233**	**2**	**101**	**35**	**3,233**
Arizona	16	1,501	0	0	16	1,501
Colorado	3	437	2	101	3	437
Idaho	0	0	0	0	0	0
Montana	0	0	0	0	0	0
Nevada	4	243	0	0	4	243
New Mexico	9	800	0	0	9	800
Utah	3	252	0	0	3	252
Wyoming	0	0	0	0	0	0
Pacific Contiguous	**26**	**2,981**	**5**	**367**	**25**	**2,881**
California	26	2,981	5	367	25	2,881
Oregon	0	0	0	0	0	0
Washington	0	0	0	0	0	0
Pacific Noncontiguous	**0**	**0**	**0**	**0**	**0**	**0**
Alaska	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	**303**	**57,697**	**120**	**31,090**	**196**	**29,427**

1 Components are not additive since some generators are included in more than one category and not all units have environmental equipment.
2 Nameplate capacity.

Notes: •Data for 2000 are final pending final approval by the Environmental Protection Agency. •Totals may not equal sum of components because of independent rounding. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts.

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

Table 25. Average Quality of Fossil Fuels Burned at U.S. Electric Utilities by Census Division and State, 1999 and 2000

Census Division State	Coal						Petroleum				Gas	
	1999			2000			1999		2000		1999	2000
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Cubic Foot	
New England	**12,656**	**0.88**	**7.9**	**12,654**	**0.85**	**7.8**	**151,244**	**0.99**	**151,633**	**0.95**	**1,030**	**1,033**
Connecticut	—	—	—	13,070	.54	7.3	151,783	.90	151,915	.84	1,028	1,022
Maine	—	—	—	—	—	—	150,653	1.03	151,415	.99	—	—
Massachusetts	12,527	.72	8.1	12,464	.69	8.2	151,055	.96	151,497	.98	1,032	1,042
New Hampshire	13,077	1.39	7.1	12,972	1.39	6.9	150,751	1.58	151,845	1.65	1,011	1,066
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	136,000	.05	136,000	.05	1,012	1,012
Middle Atlantic	**12,616**	**2.04**	**10.6**	**12,637**	**1.98**	**10.5**	**149,848**	**.79**	**150,071**	**.75**	**1,028**	**1,025**
New Jersey	12,862	1.24	9.5	12,915	1.19	8.8	150,210	.70	148,740	.55	1,032	1,030
New York	13,062	1.75	8.1	13,024	1.78	8.1	149,803	.83	150,155	.79	1,027	1,025
Pennsylvania	12,506	2.16	11.2	12,532	2.08	11.2	149,993	.61	149,886	.62	1,032	1,038
East North Central	**10,529**	**1.32**	**8.3**	**10,422**	**1.18**	**8.0**	**144,449**	**.62**	**143,419**	**.46**	**1,019**	**1,016**
Illinois	9,648	1.01	6.9	9,431	.62	5.9	143,121	.46	148,032	.57	1,021	1,019
Indiana	10,571	1.65	8.4	10,532	1.60	8.2	137,202	.28	137,064	.30	1,024	1,024
Michigan	10,392	.65	6.7	10,297	.60	6.4	147,970	.83	143,196	.52	1,015	1,014
Ohio	11,900	1.99	11.5	11,739	1.86	11.5	138,008	.28	137,844	.26	1,029	1,030
Wisconsin	9,075	.47	5.4	9,148	.42	5.2	139,999	.22	139,648	.24	1,007	1,005
West North Central	**8,310**	**.48**	**6.3**	**8,335**	**.44**	**6.1**	**144,187**	**.75**	**148,503**	**.97**	**1,010**	**1,012**
Iowa	8,558	.42	5.5	8,636	.39	5.5	138,522	.44	138,523	.43	1,014	1,010
Kansas	8,602	.46	5.6	8,652	.44	5.4	147,939	1.00	152,885	1.25	1,009	1,012
Minnesota	8,918	.50	6.3	8,884	.48	6.3	137,792	.16	137,325	.16	1,015	1,013
Missouri	8,875	.37	5.1	8,875	.31	4.9	138,282	.34	138,365	.27	1,009	1,008
Nebraska	8,500	.29	5.0	8,608	.30	4.9	142,010	.69	147,037	1.00	1,005	1,009
North Dakota	6,481	.77	9.4	6,452	.74	9.6	139,722	.49	140,743	.46	—	—
South Dakota	8,614	.60	8.2	8,440	.31	5.3	139,958	.39	139,897	.38	1,021	1,000
South Atlantic	**12,288**	**1.28**	**9.9**	**12,294**	**1.22**	**10.0**	**151,379**	**1.35**	**151,832**	**1.16**	**1,022**	**1,015**
Delaware	12,661	.99	8.9	12,655	.96	9.1	150,201	.68	148,691	.66	1,035	1,031
District of Columbia	—	—	—	—	—	—	143,522	.87	143,132	.92	—	—
Florida	12,116	1.63	8.0	12,140	1.59	8.3	151,705	1.45	152,365	1.19	1,019	1,012
Georgia	11,632	.81	9.2	11,746	.79	9.3	147,423	1.95	147,302	2.11	1,025	1,024
Maryland	12,905	1.37	9.2	12,860	1.46	9.3	150,808	.99	150,405	.90	1,041	1,044
North Carolina	12,415	.85	10.4	12,421	.83	10.7	139,299	.20	139,562	.21	1,032	1,026
South Carolina	12,775	1.16	8.7	12,724	1.10	8.5	143,047	.77	145,650	1.23	1,025	1,026
Virginia	12,729	1.05	10.3	12,752	.95	9.9	151,935	1.15	150,708	1.10	1,080	1,091
West Virginia	12,362	1.86	12.0	12,295	1.73	12.1	138,933	.34	139,340	.34	1,000	1,000
East South Central	**11,433**	**1.55**	**9.6**	**11,422**	**1.51**	**9.2**	**147,099**	**2.20**	**142,119**	**2.38**	**1,019**	**1,020**
Alabama	11,009	.98	9.4	10,907	.89	8.6	139,111	.31	138,756	.30	1,019	1,021
Kentucky	11,679	2.10	10.8	11,703	2.11	10.5	138,106	.30	138,875	.29	1,021	1,020
Mississippi	10,971	.73	6.8	11,348	1.04	7.8	148,129	2.43	142,569	2.65	1,019	1,020
Tennessee	11,739	1.62	8.6	11,716	1.56	8.6	138,039	.22	138,175	.25	—	—
West South Central	**7,743**	**.55**	**9.3**	**7,819**	**.53**	**8.7**	**148,135**	**1.01**	**143,803**	**.58**	**1,022**	**1,026**
Arkansas	8,592	.26	4.7	8,541	.28	4.8	148,484	1.16	149,421	1.44	1,018	1,019
Louisiana	8,008	.53	7.0	7,954	.53	7.3	150,954	1.17	149,335	.89	1,031	1,042
Oklahoma	8,614	.33	5.2	8,705	.27	4.8	138,834	.32	139,130	.41	1,030	1,030
Texas	7,403	.64	11.2	7,503	.62	10.3	138,038	.15	140,509	.30	1,019	1,021
Mountain	**9,781**	**.55**	**11.2**	**9,833**	**.55**	**10.9**	**139,018**	**.23**	**141,163**	**.33**	**1,020**	**1,016**
Arizona	10,225	.53	12.7	10,231	.57	12.4	139,549	.33	141,595	.36	1,010	1,017
Colorado	9,776	.38	6.6	9,847	.38	6.7	135,178	.22	135,151	.30	980	959
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	8,437	.73	9.8	8,391	.69	9.4	141,000	.50	141,000	.50	1,095	1,054
Nevada	11,958	.46	9.4	11,789	.47	9.5	144,874	.40	146,844	.59	1,043	1,023
New Mexico	9,088	.80	22.9	9,176	.80	22.3	134,722	.10	135,999	.10	1,012	1,018
Utah	11,642	.47	10.3	11,749	.46	9.5	139,220	.12	137,187	.11	1,043	1,049
Wyoming	8,736	.52	7.5	8,765	.50	7.3	139,088	.17	140,104	.15	1,045	1,044
Pacific Contiguous	**8,229**	**.64**	**10.7**	**8,112**	**.64**	**10.9**	**139,915**	**.31**	**139,153**	**.52**	**1,019**	**1,019**
California	—	—	—	—	—	—	145,548	.25	139,059	.60	1,019	1,019
Oregon	9,026	.38	6.1	8,517	.36	5.6	138,800	.50	138,800	.50	—	—
Washington	7,935	.73	12.4	7,977	.73	12.6	139,900	.07	140,000	.05	1,052	1,019
Pacific Noncontiguous	**7,675**	**.18**	**9.8**	**7,534**	**.18**	**10.7**	**149,425**	**.60**	**149,715**	**.63**	**—**	**—**
Alaska	7,675	.18	9.8	7,534	.18	10.7	132,349	.29	135,310	.27	—	—
Hawaii	—	—	—	—	—	—	149,457	.61	149,716	.63	—	—
U.S. Average	**10,197**	**1.03**	**9.1**	**10,207**	**.98**	**8.8**	**150,528**	**1.12**	**150,494**	**1.01**	**1,022**	**1,023**

Notes: •Data for 2000 are final pending approval by the Environmental Protection Agency. Data for 1999 are final. •Totals may not equal sum of components because of independent rounding.

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

Table 26. Average Flue Gas Desulfurization Costs at U.S. Electric Utilities by Census Division and State, 1996 Through 2000

Census Division State	Average O&M Costs (mills per kilowatthour)					Average Installed Costs (dollars per kilowatt)				
	1996	1997	1998	1999	2000	1996	1997	1998	1999	2000
New England	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Connecticut	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—
New Hampshire	—	—	—	—	—	—	—	—	—	—
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**2.25**	**2.21**	**2.19**	**2.17**	**2.04**	**183**	**183**	**183**	**183**	**183**
New Jersey	3.66	3.24	4.85	NM	5.00	398	398	398	398	398
New York	1.33	1.35	1.19	1.02	1.31	331	331	331	331	331
Pennsylvania	2.38	2.36	2.35	2.42	2.13	156	156	157	157	157
East North Central	**1.84**	**3.39**	**2.68**	**3.07**	**1.88**	**129**	**129**	**125**	**125**	**126**
Illinois	2.28	3.54	3.08	3.16	2.39	147	147	112	112	112
Indiana	1.68	1.59	1.51	1.79	1.66	145	146	145	145	146
Michigan	—	—	—	—	—	—	—	—	—	—
Ohio	1.92	5.47	3.79	4.43	2.08	90	90	90	90	90
Wisconsin	2.13	.10	.08	.12	.07	16	16	16	16	16
West North Central	**.53**	**.56**	**.63**	**.54**	**.47**	**78**	**78**	**78**	**77**	**77**
Iowa	1.37	1.39	1.41	1.21	1.43	202	202	202	202	202
Kansas	.35	.38	.55	.34	.19	61	61	61	61	61
Minnesota	.39	.37	.46	.49	.43	73	73	73	73	73
Missouri	1.36	1.05	NM	NM	NM	50	50	50	50	50
Nebraska	—	—	—	—	—	—	—	—	—	—
North Dakota	.72	.82	.83	.75	.75	102	102	101	99	99
South Dakota	—	—	—	—	—	—	—	—	—	—
South Atlantic	**.91**	**.83**	**1.00**	**1.05**	**.88**	**120**	**116**	**117**	**118**	**111**
Delaware	—	—	—	—	—	—	—	—	—	—
District of Columbia	—	—	—	—	—	—	—	—	—	—
Florida	.96	.90	.84	.95	.97	73	67	72	72	60
Georgia	4.82	4.85	4.04	3.61	4.45	NM	NM	NM	NM	NM
Maryland	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	—	—	—	—
South Carolina	.59	.49	.64	.89	.84	43	43	43	43	43
Virginia	.20	.02	.02	.14	.13	NM	NM	NM	NM	NM
West Virginia	1.35	1.28	1.62	1.48	.91	216	217	224	225	225
East South Central	**1.09**	**1.00**	**1.16**	**1.13**	**.94**	**143**	**143**	**143**	**143**	**143**
Alabama	.62	.75	1.02	.69	.53	80	80	80	80	80
Kentucky	1.50	1.59	1.67	1.63	1.32	140	140	139	139	139
Mississippi	.50	.68	.45	.46	.59	70	70	70	70	70
Tennessee	.37	.11	.18	.19	.31	204	204	204	204	204
West South Central	**.82**	**.81**	**.86**	**.82**	**.87**	**83**	**86**	**89**	**91**	**92**
Arkansas	—	—	—	—	—	—	—	—	—	—
Louisiana	NM	NM	NM	.81	NM	75	75	75	75	75
Oklahoma	1.14	1.26	.91	1.10	.95	92	92	92	92	92
Texas	.81	.79	.86	.81	.87	83	87	90	92	93
Mountain	**.70**	**.60**	**.57**	**.59**	**.58**	**149**	**152**	**139**	**135**	**135**
Arizona	.72	.33	.40	.52	.49	175	180	180	175	175
Colorado	.60	.49	.40	.43	.42	69	64	64	70	70
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	.92	.97	.76	.80	NM	274	274	274	267	267
Nevada	1.07	.47	.66	.72	.32	126	126	126	126	126
New Mexico	.92	.90	.83	.74	.91	162	162	93	93	93
Utah	.52	.48	.47	.47	.50	101	101	101	101	101
Wyoming	.62	.63	.60	.64	.61	137	137	137	137	137
Pacific Contiguous	**—**	**—**	**—**	**—**	**NM**	**—**	**—**	**—**	**—**	**103**
California	—	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	—	—	—	—	—	—	—
Washington	—	—	—	—	NM	—	—	—	—	103
Pacific Noncontiguous	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Alaska	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—
U.S. Average	**1.07**	**1.09**	**1.12**	**1.13**	**.96**	**128**	**129**	**126**	**125**	**124**

O&M = Operation and Maintenance

NM = Not meaningful because these plants did not generate during the year.

Notes: •Data for 2000 are final pending approval by the Environmental Protection Agency. Data for prior years are final. •Totals may not equal sum of components because of independent rounding. •A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).

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

Table 27. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 2000

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Alabama Electric Coop, Inc							
Charles R Lowman 2	538	236	7903	1.90	Spray	Limestone	85.0
Charles R Lowman 3	—	236	8005	1.90	Spray	Limestone	85.0
Arizona Electric Pwr Coop, Inc							
Apache Station 2	464	195	7901	.70	Packed	Limestone	85.0
Apache Station 3	—	195	7901	.70	Packed	Limestone	85.0
Arizona Public Service Company							
Cholla 1	1,105	114	7312	1.00	Venturi	Lime	80.0
Cholla 2	—	289	7806	1.20	Venturi	Lime	90.0
Cholla 4	—	414	8106	1.20	Packed	Lime	95.0
Four Corners 1	2,270	190	7201	.80	Venturi	Lime	72.0
Four Corners 2	—	190	7201	.80	Venturi	Lime	72.0
Four Corners 3	—	253	7201	.80	Venturi	Lime	72.0
Four Corners 4	—	818	8501	.80	Tray	Dolomitic Limestone	72.0
Four Corners 5	—	818	8501	.80	Tray	Dolomitic Limestone	72.0
Atlantic City Electric Company							
B L England 2	476	163	9501	3.20	Spray	Limestone	93.0
Basin Electric Power Coop							
Antelope Valley FGD1	870	435	8307	1.20	Spray Dry	Lime/Alkaline Fly Ash	81.0
Antelope Valley FGD2	—	435	8511	1.20	Spray Dry	Lime/Alkaline Fly Ash	81.0
Laramie R Station 1	1,710	570	8007	.80	Spray	Limestone	90.0
Laramie R Station 2	—	570	8107	.80	Spray	Limestone	90.0
Laramie R Station 3	—	570	8405	.50	Spray Dry	Lime/Alkaline Fly Ash	85.0
Black Hills Power Inc							
Neil Simpson II 2	—	—	9511	.90		Lime	92.0
Central Louisiana Elec Co Inc							
Dolet Hills 1	721	721	8604	.70	Spray	Limestone	76.0
Cincinnati Gas & Electric Co							
East Bend 2	669	669	8103	5.20	Spray Dry	Lime	99.0
W H Zimmer 1	1,426	1,426	9103	4.50	Spray	Lime	99.0
Columbus Southern Power Co							
Conesville 5	2,175	444	7705	7.90	Spray	Lime	89.7
Conesville 6	—	444	7708	7.90	Spray	Lime	89.7
Deseret Generation & Tran Coop							
Bonanza 1-1	400	400	8605	.50	Spray	Limestone	95.0
East Kentucky Power Coop, Inc							
H L Spurlock 2	814	508	8306	3.60	Spray Dry	Lime	90.0
Georgia Power Company							
Yates Y1FG	1,488	123	9210	2.50	Bubbling Reactor	Limestone	90.0
Golden Valley Elec Assn, Inc							
Healy 2	—	—	301	.20	Spray Dry	Limestone	70.0
Grand Haven City of							
J B Sims 3	78	58	8308	2.80	Tray	Lime	90.0
Grand River Dam Authority							
GRDA 2	1,010	520	8604	1.50	Spray Dry	Lime/Alkaline Fly Ash	85.0
Great River Energy							
Coal Creek 1	1,210	605	7908	1.00	Spray	Lime	90.0
Coal Creek 2	—	605	8107	1.00	Spray	Lime	90.0
Elk River 1	46	46	8903	—	Spray Dry	Lime	90.0
Stanton 10	172	172	8206	.70	Spray Dry	Lime	70.0

See footnotes at end of table.

Table 27. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 2000 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Hamilton Dept of Public Utils							
Hamilton 9	111	51	9904	3.40	Other	Lime	90.0
Hoosier Energy R E C, Inc							
Merom 1FGD	1,080	540	8309	3.00	Spray	Limestone	90.0
Merom 2FGD	—	540	8202	3.00	Spray	Limestone	90.0
Indianapolis Power & Light Co							
Petersburg 1	1,873	253	9605	4.50	Spray	Limestone	95.0
Petersburg 2	—	471	9605	4.50	Spray	Limestone	95.0
Petersburg 3	—	574	7711	—	Tray	Limestone	85.0
Petersburg 4	—	574	8604	—	Spray	Limestone	95.0
JEA							
St Johns River Power 1	1,358	679	8703	2.20	Spray	Limestone	90.0
St Johns River Power 2	—	679	8805	2.20	Spray	Limestone	90.0
Kansas City Power & Light Co							
Lacygne 1	1,579	893	7306	5.40	Venturi	Limestone	80.0
Kentucky Utilities Company							
Ghent 1	2,226	557	9412	3.50	Spray	Limestone	95.0
Green River 1	264	75	7510	3.80	Venturi	Lime	80.0
Lakeland City of							
C D McIntosh Jr 3	593	364	8209	1.80	Spray	Limestone	85.0
Los Angeles Dept of Wtr & Pwr							
Intermountain 1CCC	1,640	820	8607	.60	Spray	Limestone	90.0
Intermountain 2CCC	—	820	8707	.60	Spray	Limestone	90.0
Louisville Gas & Electric Co							
Cane Run 4	645	163	7612	3.50	Spray	Other	85.0
Cane Run 5	—	209	7805	3.50	Spray	Other	85.0
Cane Run 6	—	272	7904	3.50	Tray	Other	90.0
Mill Creek 1	1,717	356	8112	6.00	Spray	Limestone	90.0
Mill Creek 2	—	356	8012	6.00	Spray	Limestone	90.0
Mill Creek 3	—	463	8510	5.00	Spray	Limestone	90.0
Mill Creek 4	—	544	8207	6.30	Spray	Limestone	90.0
Trimble County 1	566	566	9012	4.50	Spray	Limestone	90.7
Lower Colorado River Authority							
Sam Seymour 3	1,703	475	8804	1.70	Spray	Limestone	90.0
Marquette City of							
Shiras 3	40	40	8307	.50	Spray Dry	Limestone	80.0
Michigan South Central Pwr Agy							
Endicott Generating 1	55	50	8305	4.30	Spray	Limestone	90.0
Minnesota Power, Inc.							
Clay Boswell AQCS2	1,073	558	8004	1.00	Spray	Alkaline Fly Ash	83.2
Clay Boswell SCR3	—	365	7302	1.00	Spray	Alkaline Fly Ash	25.4
Syl Laskin SCR1	116	58	7105	1.00	Spray	Alkaline Fly Ash	—
Syl Laskin SCR2	—	58	7105	1.00	Spray	Alkaline Fly Ash	—
Minnkota Power Coop, Inc							
Milton R Young FGD2	734	477	7806	1.20	Spray	Lime/Alkaline Fly Ash	77.9
Monongahela Power Company							
Harrison 1	2,052	684	9411	4.00	Spray	Lime	98.0
Harrison 2	—	684	9411	4.00	Spray	Lime	98.0
Harrison 3	—	684	9411	4.00	Spray	Lime	98.0
Pleasants 1	1,368	684	7903	4.50	Tray	Lime	90.0
Pleasants 2	—	684	8012	4.50	Tray	Lime	90.0

See footnotes at end of table.

Table 27. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 2000 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Muscatine Power and Water							
Muscatine Plant # 1 9	294	176	8306	3.20	Spray	Limestone	96.0
Nevada Power Company							
Reid Gardner 1	612	114	7404	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 2	—	114	7404	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 3	—	114	7607	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 4	—	270	8307	.90	Spray	Sodium Carbonate	85.0
Northern Indiana Pub Serv Co							
Bailly 78	616	616	9206	—	Packed	Limestone	90.0
R M Schahfer 17	1,943	424	8304	3.20	Spray	Limestone	90.0
R M Schahfer 18	—	424	8602	3.20	Spray	Limestone	90.0
Northern States Power Company							
Red Wing 1	—	—	12	—	Spray	Lime	75.0
Red Wing 2	—	—	104	—	Spray	Lime	75.0
Riverside 7	404	165	8101	1.30	Spray Dry	Lime/Alkaline Fly Ash	70.0
Sherburne Co 1	2,129	660	7605	.90	Venturi	Alkaline Fly Ash	50.0
Sherburne Co 2	—	660	7704	.90	Spray	Alkaline Fly Ash	50.0
Sherburne Co 3	—	809	8711	.90	Spray Dry	Lime/Alkaline Fly Ash	72.3
Wilmarth 1	—	—	9101	—	Spray	Lime	70.0
Wilmarth 2	—	—	9101	—	Spray	Lime	70.0
Ohio Power Company							
Gen J M Gavin 1	2,600	1,300	9412	3.50	Spray	Lime	95.0
Gen J M Gavin 2	—	1,300	9503	3.50	Spray	Lime	95.0
Orlando Utilities Commission							
Stanton Energy Ctr 1	929	465	8707	3.50	Spray	Limestone	90.0
Stanton Energy Ctr 2	—	465	9606	3.40	Spray	Limestone	95.0
Otter Tail Power Company							
Coyote FGD1	450	450	8105	.80	Spray Dry	Lime/Alkaline Fly Ash	70.0
Owensboro Municipal Utilities							
Elmer Smith FGD	445	445	9411	3.50	Spray	Limestone	96.0
PacifiCorp							
Dave Johnston SC44	817	360	7202	.40	Venturi	Lime	—
Hunter 1	1,339	446	7806	.60	Spray	Lime	80.0
Hunter 2	—	446	8006	.60	Spray	Lime	80.0
Hunter 3	—	446	8306	.60	Spray	Limestone	90.0
Huntington 1	893	446	7802	.60	Spray	Lime	80.0
Jim Bridger SC71	2,260	561	9009	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC72	—	561	8609	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC73	—	578	8809	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC74	—	561	7911	1.00	Tray	Soda Liquor Waste	91.0
Naughton 3	707	326	8110	.80	Tray	Sodium Carbonate	70.0
Wyodak SC91	362	362	8612	.80	Spray Dry	Lime	75.2
Pennsylvania Power Company							
Bruce Mansfield 1	2,741	914	7604	4.80	Venturi	Lime	92.1
Bruce Mansfield 2	—	914	7710	4.80	Venturi	Lime	92.1
Bruce Mansfield 3	—	914	8009	4.80	Spray	Lime	92.1
Platte River Power Authority							
Rawhide 101	294	294	8404	.30	Spray Dry	Lime/Alkaline Fly Ash	80.0
Public Service Co of Colorado							
Arapahoe 4	232	100	9306	.40	Spray Dry	Other	20.0
Cherokee 1	710	100	9802	.40	Spray Dry	Other	50.0
Cherokee 4	—	350	8905	.40	Spray Dry	Other	26.0
Hayden H1	465	190	9812	.40	Spray Dry	Lime/Alkaline Fly Ash	85.0
Hayden H2	—	275	9906	.40	Spray Dry	Lime/Alkaline Fly Ash	85.0

See footnotes at end of table.

Table 27. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 2000 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Public Service Company of NM							
San Juan 1	1,848	369	9810	0.90	Spray	Limestone	75.0
San Juan 2	—	369	9810	.90	Spray	Limestone	75.0
San Juan 3	—	555	9810	.90	Spray	Limestone	75.0
San Juan 4	—	555	9810	.90	Spray	Limestone	75.0
PECO Energy Company							
Cromby 1	418	188	8212	2.60	Spray	Magnesium Oxide	95.0
Eddystone 1	1,489	354	8212	2.60	Spray	Magnesium Oxide	92.0
Eddystone 2	—	354	8212	2.60	Spray	Magnesium Oxide	92.0
PSI Energy, Inc							
Gibson 4	3,340	668	9501	3.50	Spray	Limestone	92.0
Gibson 5	—	668	8210	4.40	Spray	Limestone	86.0
Reliant Energy HL&P							
Limestone FGD1	1,627	813	8510	3.10	Spray	Limestone	90.0
Limestone FGD2	—	813	8610	3.10	Spray	Limestone	90.0
W A Parish FGD8	3,953	615	8212	.50	Spray	Limestone	85.0
Richmond City of							
Whitewater Valley LFC	—	—	9410	2.10	Spray Dry	Limestone	72.5
Salt River Project							
Coronado FGD1	822	411	7912	1.00	Spray	Limestone	82.5
Coronado FGD2	—	411	8011	1.00	Spray	Limestone	82.5
Navajo 1	2,409	803	9908	.60	Spray	Limestone	92.0
Navajo 2	—	803	9811	.60	Spray	Limestone	92.0
Navajo 3	—	803	9711	.60	Spray	Limestone	92.0
San Antonio Public Service Bd							
J K Spruce FGD1	546	546	9212	.60	Spray	Limestone	70.0
San Miguel Electric Coop, Inc							
San Miguel SM-1	410	410	8201	2.00	Spray	Limestone	86.0
Seminole Electric Coop, Inc							
Seminole 1	1,429	715	8402	3.00	Spray	Limestone	90.0
Seminole 2	—	715	8412	3.00	Spray	Limestone	90.0
Sierra Pacific Power Company							
Valmy 2	521	267	8507	.50	Spray Dry	Lime	70.0
Sikeston City of							
Sikeston 1	261	261	8111	2.80	Venturi	Limestone	75.5
South Carolina Electric&Gas Co							
Cope COP1	417	417	9511	1.90	Spray Dry	Lime	95.0
South Carolina Pub Serv Auth							
Cross 1	1,147	591	9505	1.10	Spray	Limestone	90.0
Cross 2	—	556	8312	1.60	Spray	Limestone	81.4
Winyah 2	1,260	315	7707	1.10	Venturi	Limestone	45.0
Winyah 3	—	315	8006	2.30	Spray	Limestone	90.0
Winyah 4	—	315	8111	1.70	Spray	Limestone	90.4
South Mississippi El Pwr Assn							
R D Morrow 1	400	200	7809	1.50	Spray	Limestone	52.7
R D Morrow 2	—	200	7906	1.50	Spray	Limestone	52.7
Southern Illinois Power Coop							
Marion 4	272	173	7904	4.40	Venturi	Limestone	89.4
Southern Indiana Gas & Elec Co							
A B Brown 1	530	265	7904	4.50	Spray	Sodium Ash	85.0

See footnotes at end of table.

Table 27. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 2000 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Southern Indiana Gas & Elec Co							
A B Brown 2	—	265	8602	4.50	Spray	Sodium Ash	90.0
F B Culley 2-3	415	369	9501	3.80	Spray	Limestone	95.0
Southwestern Electric Power Co							
Pirkey 1	721	721	8501	1.50	Spray	Limestone	85.0
Soyland Power Coop Inc							
Pearl Station 1A	22	22	7611	3.40	Venturi	Other	11.8
Springfield City of							
Southwest Power St 1	194	194	7704	3.20	Tray	Limestone	87.0
Springfield Water Light&Power							
Dallman 33	388	207	8012	3.30	Packed	Limestone	95.0
Sunflower Electric Power Corp							
Holcomb SDA1	349	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb SDA2	—	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb SDA3	—	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
SITHE Northeast Managment Co							
Conemaugh 1	1,872	936	9412	2.70	Spray	Limestone	95.0
Conemaugh 2	—	936	9511	2.70	Spray	Limestone	95.0
Tampa Electric Company							
Big Bend FGD1	1,823	891	9912	3.30	Spray	Limestone	95.0
Big Bend FGD4	—	932	8502	3.50	Spray	Limestone	95.0
Tennessee Valley Authority							
Cumberland 1	2,600	1,300	9501	4.00	Spray	Limestone	95.0
Cumberland 2	—	1,300	9501	4.00	Spray	Limestone	95.0
Paradise 1	2,558	704	8309	3.20	Spray	Limestone	84.2
Paradise 2	—	704	8312	3.20	Spray	Limestone	84.2
Widows Creek 7	1,969	575	8112	4.00	Spray	Limestone	83.4
Widows Creek 8	—	550	7801	4.50	Tray	Limestone	80.0
Texas Municipal Power Agency							
Gibbons Creek 1	454	454	8310	.30	Spray	Limestone	90.0
Tri-State G & T Assn, Inc							
Craig C1	1,339	446	8010	.60	Spray	Limestone	85.0
Craig C2	—	446	8005	.60	Spray	Limestone	85.0
Craig C3	—	446	8410	.70	Spray Dry	Lime	85.0
Tucson Electric Power Company							
Springerville 1	850	425	8506	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3
Springerville 2	—	425	9006	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3
TXU Electric Company							
Martin Lake 1	2,380	793	7705	.90	Spray	Limestone	91.0
Martin Lake 2	—	793	7805	.90	Spray	Limestone	91.0
Martin Lake 3	—	793	7904	.90	Spray	Limestone	91.0
Monticello 3	1,980	793	7808	1.50	Spray	Limestone	74.0
Sandow 4	591	591	8105	1.60	Spray	Limestone	73.9
Virginia Electric & Power Co							
Clover 1	848	424	9510	2.00	Spray	Limestone	90.0
Clover 2	—	424	9603	2.00	Spray	Limestone	90.0
Mt Storm 3	1,662	522	9501	2.00	Spray	Limestone	90.0
West Texas Utilities Company							
Oklaunion 1	720	720	8612	.40	Spray	Limestone	86.8

See footnotes at end of table.

Table 27. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 2000 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Western Kentucky Energy Corp							
D B Wilson W1	509	509	8611	3.80	Spray	Limestone	90.0
HMP&L Station 2 H1	365	180	9506	4.20	Tray	Lime	95.0
HMP&L Station 2 H2	—	185	9506	4.20	Tray	Lime	95.0
R D Green G1	527	264	7912	4.00	Spray	Lime	90.0
R D Green G2	—	264	8101	4.00	Spray	Lime	90.0
Western Resources, Inc							
Jeffrey EC 1	2,160	720	7807	.30	Spray	Limestone	60.0
Jeffrey EC 2	—	720	8005	.30	Spray	Limestone	60.0
Jeffrey EC 3	—	720	8305	.30	Spray	Limestone	60.0
Lawrence EC 4N	604	114	6906	.90	Venturi	Limestone	73.0
Lawrence EC 4S	—	114	6906	.90	Venturi	Limestone	73.0
Lawrence EC 5	—	403	7105	.90	Venturi	Limestone	52.0
Wisconsin Electric Power Co							
Port Washington 1	320	80	9308	1.20	Spray	Sodium Carbonate	50.0
Port Washington 4	—	80	9408	1.20	Spray	Sodium Carbonate	50.0

Notes: •Data for 2000 are final pending approval by the Environmental Protection Agency. • SO2 = Sulfur Dioxide; WT=weight; FGD=Flue Gas Desulfurization.

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

U.S. Electric Power Transactions

This chapter provides summary information for the U.S. electric power industry on its operations and wholesale electricity trade at the international (Canada and Mexico), national, and North American Electric Reliability Council (NERC) region levels.[11] Generating capability, generation from utility and nonutility sources, and end-user consumption are also presented.

Background

An electric power system is a group of generation, transmission, distribution, communication, and other facilities that are physically connected and operated as a single unit under one control. Transmission and distribution lines and associated facilities are used to transmit electricity from its point of origin (the generator) to the ultimate consumer. Although, due to its physical characteristics, electricity flows along all available paths, it follows the path of least resistance. The flow of electricity must be closely monitored to ensure that sufficient generating capacity is available and on-call to satisfy all demand (load) for electricity placed on the power system. In addition, for system standardization and reliability purposes, the flow is maintained at a frequency of 60 cycles per second.

The flow of electricity within the system is maintained and monitored by dispatch centers having control and security responsibilities. Historically, the dispatch center inventoried and prioritized all generating capacity available to it, tracked transactions involving the buying or selling of either electric power or capacity, monitored current load, and anticipated future load on the system. In the future, this responsibility may be handled differently. How, is now being determined by participants in the new electric power industry.

It is the responsibility of the dispatch center to match the supply of electricity with demand. The demand for electricity is not constant in nature. That is, load requirements fluctuate continuously, based on such factors as time of day, season of the year, and the characteristics of territory served by the system. Nonetheless, the dispatch center must be ready to meet the highest level of load placed on the system. The dispatch center must accommodate the loss of generating facilities (both planned and unexpected). In addition, the center must monitor transmission lines to determine whether the flow of electricity is approaching the carrying limits of the lines. In order to carry out its responsibilities in a timely fashion, the dispatch center is authorized to buy and sell electricity based on system requirements.

Authority for these transactions has been preapproved under interconnection agreements (contracts) that have been signed by all the electric utilities that are physically interconnected and/or have coordination agreements with other utilities not physically interconnected. (All these agreements are subject to regulatory approval.) These agreements include transaction categories for purchases, sales for resale, exchanges, and wheeling of energy. In the near future, a competitive power market will address this allocation of resources through the open buying and selling of electricity and the independent pricing of system operating costs which were bundled into the total charges for electricity.

Purchase transactions involve buying power from electric utilities and nonutility producers of electricity. Sales for resale transactions refer to power sold by one electric utility or power marketer to other electric utilities for distribution. (Direct interstate wholesale sales to retail customers by power marketers are not authorized.) Some transactions involving the trade of electric energy are based on availability of excess generating capacity or diversity in load requirements. For example, if one electric utility has its lowest load during the winter season, it may arrange to offer its available excess generating capacity in exchange for excess generating capacity available at a facility with low summer load. This type of arrangement is an exchange transaction. However, the repayment or replacement of exchange energy may have extended over several years. The use of exchange transactions is disappearing. Spot and futures markets will eventually replace this type of transaction. Wheeling transactions are the movement of electricity from one utility to another utility over the transmission facilities of one or more intervening utilities.

[11] The NERC is an organization established by the electric utility industry for maintaining, coordinating, and promoting reliability among the interconnected systems of North America.

Electric Utility Transactions

Electric power transactions *(wholesale electricity trade)* allowed electric utilities to acquire power, to share resources, and to provide mutual assistance in times of potential and actual need. They allowed the utility systems to provide lower cost service to their consumers by taking advantage of the load diversity of each utility. These transactions also allowed each utility to conserve its own resources, to share the benefits of reduced operating costs with its consumers, to receive emergency energy support from other utilities, and to reduce the cost of its own requirements for operating reserve. Competitive markets (spot and futures) are expected to be substituted as the electric utility industry continues to change from a monopoly based structure. However, due to the complexity of electric power transactions involving the specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, the reporting of both the classification and quantity of each transaction among utilities is expected to be inconsistent in the future as well.

Electric utilities originally became interested in energy transactions because of the savings gained from reduced or avoided production costs. They avoided building expensive additional capacity by obtaining power from other sources. Purchasing power from other utilities helped utilities meet peak load without using expensive oil- or gas-fired turbines. Similarly, utilities benefited from being able to delay or stagger construction of additional baseload plants. Electric utilities have also delayed or replaced new plant construction by purchasing electricity from nonutility generators under long-term contracts. Now, opportunities are developing for price based decisions.

Power Pool Transactions

In addition to dealing in one-time purchase and sale transactions, many electric utilities have joined together and formed power pools to achieve better operating efficiencies and to gain additional support for maintaining a functional electrical system. Thus, they share the benefits achieved by joint planning, coordinated use of generating and transmission facilities, and/or common coverage of facility outages. This coordination also provides the opportunity to achieve short-term saving, largely from varying fuel prices and the costs associated with different mixes of capacity. The future of this type of agreement will hinge on the full implementation of the Federal Energy Regulatory Commission (FERC) Orders that directed changes be made to these agreements.

Power pools can be made up of two electric utilities, like the Michigan Electric Coordinated System (Detroit Edison Company and Consumer Power Company), include all the major investor-owned utilities within a State (the New York Power Pool), or cross State lines (the PJM Power Pool includes parts or all of Pennsylvania, New Jersey, Maryland, and Delaware).

Power pools may run under a single-system dispatch to meet combined-load requirements and maintenance programs, or they may just share the benefits of planned or hourly wholesale sales of power and energy among the member utilities. They may also have responsibility for coordinating flow within the geographic area of the interconnected systems. In any case, they are bound by the operating standards established by the electric power industry. These standards require the coordination and maintenance of system stability and reliable service on a regional basis.

NERC Profile

The North American Electric Reliability Council (NERC) consists of 10 regional reliability councils whose memberships comprise essentially all of the electric utility systems in the contiguous United States, Canada, and Baja California Norte, Mexico. The regional councils are responsible for maintaining and setting standards for the reliability and stability of the electricity flowing within the three power grids (the Eastern Power Grid, the Western Power Grid, and the Electric Reliability Council of Texas Power Grid) present in the contiguous United States. The data for NERC regions in this publication are based upon the assignment of all electric utilities to an individual region and are for the U.S. portion of the regions only (Figure 9).

Regulation of U.S. Electric Utility Transactions

The Federal Energy Regulatory Commission (FERC) is responsible for regulating interstate wholesale transactions. U.S. electric utilities and potential power marketers (registration and rate structure) file with the FERC for approval of proposed rate schedules for transmission services and charges, and for wholesale transactions. Historically, transmission filings covered the allocation of electric power flows on the transmission line systems. Other categories described in the filings usually include the responsibilities of the utilities to one another during normal and emergency conditions, operating-reserves, support, diversity exchanges, and unscheduled or inadvertent-energy flows. Authority was granted the FERC by the Energy Policy Act of 1992 to ensure that any wholesale generator--electric utility or nonutility--can access the transmission grid to reach its markets. After application, the FERC can order electric utilities to provide transmission (wheeling) services, provided that the proposed transaction is in the public interest and meets key criteria related to pricing, reliability, and self-dealing.

Wholesale transactions include *capacity* sales, *energy* sales, and *energy exchanges.* Wholesale transactions are further divided by duration of the sale and the type of capacity and energy sold. The length of the sale can be for an hour, a day, a week, a month (or several months), a season, several years, or some combination of these time periods.

Capacity sales are usually considered *firm* sales (that is, associated energy may be taken, or the capacity must be paid for if the energy is not taken; and the delivery is scheduled during normal system operating conditions). This capacity may be made available from the entire system or from an identified generating unit. The capacity offered in these transactions may be available only during a set period of a given season, for an off-peak time of the day, or from a generator fired by a particular fuel that is currently not fully utilized. The energy associated with this capacity sale, if required, has a separate cost schedule from the capacity charge attached to each kilowatt of power.

Nonfirm sales, sometimes called energy, economy, or interruptible sales, do not include a demand or capacity charge in the price of the transaction. These transactions are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions. The sales are often based on splitting the benefits gained by the parties involved. They are used to gain operational savings, for example, by avoiding the use of more expensive fuels, or by selling electricity generated by the spillage of excess reservoir water.

Energy exchanges involve transfers of energy to other systems at no monetary charge. The energy must be returned in kind at a later date agreed upon by both parties. Otherwise, the receiving party pays for the energy received. The incidental miscellaneous transfer of energy and inadvertent flow are also handled in the same manner. In total, these wholesale transactions have become very important tools used by the U.S. electric utility industry to reduce costs and avoid expensive new capacity.

Other Wholesale Electricity Trade Concerns

Environmental issues associated with air, solid-waste disposal, water quality, and aquatic habitat have received increasing attention from utility and power plant operators. Plant operating restrictions caused by air and water emissions have altered or restricted the dispatching of some facilities and in certain cases, plant cooling water sources have been contaminated or shut down due to aquatic organisms. Transmission line right-of-way and projected line construction are also being affected because of concerns linked to generated electromagnetic forces surrounding the transmission lines. The issue of who will build new transmission lines in the future is uncertain. Changing responsibilities in the electric power industry may make it difficult to justify new construction in one State that address requirements for new transmission capability or reliability support coming from another State.

Legislative and regulatory initiatives have been implemented to address emissions at power plants. For example, the Clean Air Act Amendments of 1990 established emission allowances for nitrogen oxides, sulfur dioxide, and carbon dioxide for power plants based on historical levels. (The implementation occurs in two phases: 1995 for an identified set of utility plants and 2000 for all others.) The cost of compliance is expected to change the cost of the output of some existing plants, alter construction approaches to new facilities, cause changes to the fuel use of other power plants, and cause an reexamination by powerplant operators of what can be done to reduce emissions. The impact of the changes will affect the future availability of power from power plants emitting high levels of these gases and increase the attractiveness of acquiring power from other facilities and electrical systems emitting low levels. In addition, traditional wholesale trade patterns are going to be altered by changing practices in the new electric power industry. Cost issues will change to one of price. Availability of electrical energy will change to issues concerning more effective capacity utilization and that may mean more use of high emission source generators.

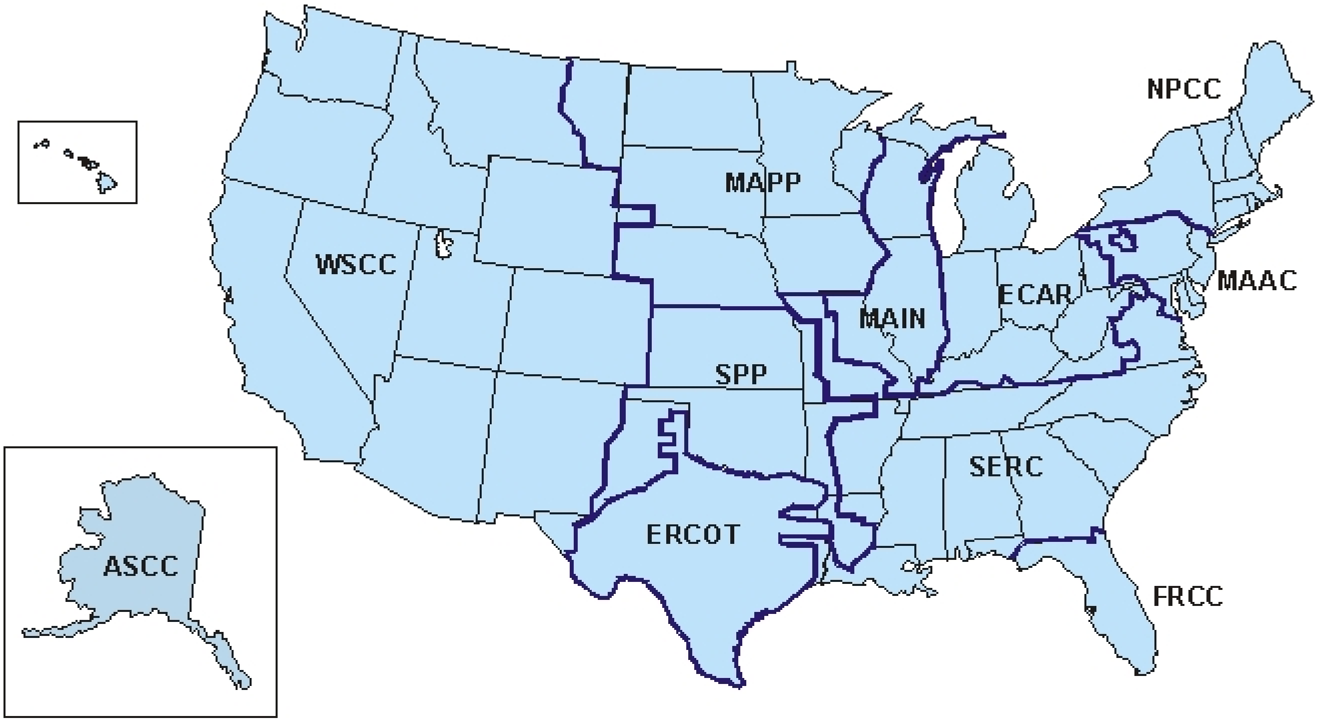
International Transactions

U.S. electric utilities and power marketers have taken advantage of being able to enter into international trade agreements to acquire energy from Canada and Mexico. These trade agreements between Canadian utilities and U.S. participants in the electric power industry cover a variety of transaction options. The options include purchasing nonfirm energy from relatively inexpensive renewable resources (hydroelectric from Canada and geothermal from Mexico); acquiring additional generating capability to support contracted requirements for supply; the holding of purchased electricity (as reservoir water) to be reacquired when needed; and sharing the benefits of coordinated operations planning for the electrical systems. In some instances, consumers can be served more efficiently if they are connected to foreign transmission lines, because they are geographically closer to those lines.

Data Sources

Statistics on electricity transactions among U.S. electric utilities and on international electricity trade (including the United States, Canada, and Mexico) are presented in the following tables. These data were obtained from the Form EIA-861, “The Annual Electric Utility Report”; the Form EIA-860A, “Annual Electric Generator Report - Utility” for 1998 and 1999; For 1997 and prior: Form EIA-860, “Annual Electric Generator Report”; the Form EIA-411, “Coordinated Bulk Power Supply Program Report”; and the Department of Energy, Office of the Assistant Secretary for Fossil Energy, Form FE-781R, “Annual Report of International Electric Export/Import Data.”

Figure 9. North American Electric Reliability Council Regions for the Contiguous United States, Alaska and Hawaii



ECAR – East Central Area Reliability Coordination Agreement
ERCOT – Electric Reliability Council of Texas
FRCC – Florida Reliability Coordinating Council
MAAC – Mid-Atlantic Area Council
MAIN – Mid-America Interconnected Network
MAPP – Mid-Continent Area Power Pool
NPCC – Northeast Power Coordinating Council
SERC – Southeastern Electric Reliability Council
SPP – Southwest Power Pool
WSCC – Western Systems Coordinating Council

Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.
Source: North American Electric Reliability Council.

Table 28. Sources and Disposition of Electricity at Traditional U.S. Electric Utilities, 1996 Through 2000

(Million Kilowatthours)

Item	1996	1997	1998	1999	2000
Source					
Net Generation	3,099,945	3,144,756	3,219,994	3,189,466	3,052,053
Purchases from Utilities	1,465,174	1,634,886	1,668,665	1,633,818	2,250,382
Purchases from Nonutilities	229,018	243,213	258,534	315,757	[1] 0
Net Exchange	–11,677	–17,088	–858	1,787	8,557
Net Wheeling	7,324	7,135	8,076	8,361	7,599
Disposition					
Sales to Ultimate Consumers	3,097,810	3,139,761	3,239,818	3,235,899	3,309,550
Requirements and Nonrequirements Sales for Resale	1,431,179	1,616,318	1,664,081	1,635,614	1,715,582
Energy Furnished Without Charge	6,205	6,318	5,109	5,054	6,848
Energy Used by Utility Electric Department	13,886	13,424	10,808	12,557	19,248
Energy Losses[2]	238,695	234,926	232,112	250,193	257,057

[1] Data on purchases from nonutilities were not collected on the Form EIA-861.

[2] These values are not measured; however, they represent losses and unaccounted for energy. These values are calculated in order that source and disposition of energy are equivalent.

Notes: •Data are final. •Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Differences in this net generation data and net generation reported on the Form EIA-759, ''Monthly Power Plant Report,'' (Table 1) occur due to the time frame in reporting. Since the components of net generation are provided monthly by the Form EIA-759 by prime mover and energy source, the Form EIA-759 is used as the official Energy Information Administration source for net generation. •Totals may not equal sum of components because of independent rounding. •''Sales to Ultimate Consumers'' for the years 1996 through 2000 do not include sales by retail power marketers in state-level deregulated markets. For further information on these transactions see *Electric Sales and Revenue* for those years. •The source and disposition of electricity represent the total volume of energy transactions between utilities. These data should not be summed as they are the aggregation of data reported for each utility and could be double counted due to the nature and types of electricity trade. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 29. Net Generation from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1996	1997	1998	1999	2000
ECAR	528,214	530,896	528,252	529,712	527,751
ERCOT	218,497	221,407	237,176	232,726	236,673
FRCC	—	146,217	167,910	165,058	168,229
MAAC	200,669	204,269	222,509	217,624	137,459
MAIN	231,315	216,732	221,883	237,971	212,593
MAPP(U.S.)	132,689	133,885	139,209	146,186	134,936
NPCC(U.S.)	185,521	188,063	178,096	138,380	110,169
SERC	740,784	617,191	747,031	748,523	762,809
SPP	276,205	278,701	184,483	179,774	184,667
WSCC(U.S.)	574,878	596,496	582,768	582,448	565,355
Contiguous U.S.	**3,088,772**	**3,133,858**	**3,209,317**	**3,178,401**	**3,040,641**
ASCC	5,178	5,013	4,719	4,949	5,165
Hawaii[1]	5,994	5,886	5,958	6,115	6,247
U.S. Total	**3,099,945**	**3,144,756**	**3,219,994**	**3,189,466**	**3,052,053**

[1] Net generation by NERC region is identified as in the region where a utility's administrative headquarters are located. Therefore, all generation for Citizens Utilities is in NPCC.

Notes: •Data are final. •Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Differences in this net generation data and net generation reported on the Form EIA-759, ''Monthly Power Plant Report,'' (Table 1) occur due to the time frame in reporting. Since the components of net generation are provided monthly by the Form EIA-759 by prime mover and energy source, the Form EIA-759 is used as the official Energy Information Administration source for net generation. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 30. U.S. Electric Utility Sales to Bundled Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1996 Through 2000

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1996		
ECAR	483,750	149,381	117,924	206,397	10,048
ERCOT	235,780	87,324	60,959	77,113	10,383
FRCC	—	—	—	—	—
MAAC	229,013	81,141	87,597	57,336	2,939
MAIN	219,978	66,015	63,919	80,655	9,390
MAPP(U.S.)	137,767	48,099	30,233	55,600	3,835
NPCC(U.S.)	241,258	79,650	95,532	52,236	13,840
SERC	714,441	288,556	178,815	227,381	19,689
SPP	277,115	96,689	70,230	101,332	8,864
WSCC(U.S.)	544,937	181,329	177,304	167,988	18,316
Contiguous U.S.	**3,084,040**	**1,078,184**	**882,513**	**1,026,039**	**97,304**
ASCC	4,779	1,766	2,250	584	179
Hawaii	8,991	2,540	2,662	3,733	55
U.S. Total	**3,097,810**	**1,082,491**	**887,425**	**1,030,356**	**97,539**
			1997		
ECAR	485,244	146,537	119,440	209,236	10,030
ERCOT	243,029	88,459	61,965	81,583	11,022
FRCC	149,249	73,598	56,159	14,364	5,128
MAAC	228,115	79,143	88,156	57,952	2,864
MAIN	222,714	65,456	64,920	82,790	9,548
MAPP(U.S.)	141,200	48,375	30,738	58,069	4,019
NPCC(U.S.)	242,428	79,286	97,605	51,641	13,896
SERC	571,424	208,635	152,495	195,263	15,030
SPP	282,082	97,417	71,826	103,442	9,398
WSCC(U.S.)	560,473	184,603	180,278	173,858	21,734
Contiguous U.S.	**3,125,958**	**1,071,510**	**923,583**	**1,028,197**	**102,668**
ASCC	4,840	1,726	2,180	756	178
Hawaii	8,963	2,531	2,677	3,701	55
U.S. Total	**3,139,761**	**1,075,767**	**928,440**	**1,032,653**	**102,901**
			1998		
ECAR	494,942	149,895	124,956	210,679	9,411
ERCOT	258,684	96,749	66,654	83,395	11,886
FRCC	175,214	89,614	63,480	16,384	5,736
MAAC	230,855	79,331	90,719	58,007	2,798
MAIN	224,576	67,011	66,753	81,167	9,646
MAPP(U.S.)	143,942	48,651	31,625	59,725	3,941
NPCC(U.S.)	243,180	79,623	97,862	51,396	14,298
SERC	723,580	266,502	187,200	251,340	18,538
SPP	165,351	58,274	48,405	51,991	6,680
WSCC(U.S.)	565,531	187,814	185,893	171,497	20,327
Contiguous U.S.	**3,225,854**	**1,123,463**	**963,546**	**1,035,583**	**103,261**
ASCC	5,095	1,768	2,307	818	202
Hawaii	8,870	2,504	2,675	3,636	55
U.S. Total	**3,239,818**	**1,127,735**	**968,528**	**1,040,038**	**103,518**

See footnotes at end of table.

Table 30. U.S. Electric Utility Sales to Bundled Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1996 Through 2000 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1999		
ECAR	506,007	155,266	126,202	214,969	9,571
ERCOT	257,735	95,278	68,391	82,090	11,975
FRCC	174,971	87,680	65,042	16,519	5,729
MAAC	207,250	81,379	83,213	39,893	2,765
MAIN	228,164	67,191	70,514	80,503	9,956
MAPP(U.S.)	147,503	50,094	33,181	60,257	3,970
NPCC(U.S.)	244,211	84,779	94,474	50,674	14,284
SERC	733,887	267,208	192,739	254,914	19,026
SPP	160,826	55,463	48,130	50,833	6,400
WSCC(U.S.)	561,067	192,006	183,548	162,689	22,824
Contiguous U.S.	**3,221,621**	**1,136,345**	**965,434**	**1,013,341**	**106,502**
ASCC	5,293	1,866	2,385	844	198
Hawaii[2]	8,985	2,551	2,782	3,598	55
U.S. Total	**3,235,899**	**1,140,761**	**970,601**	**1,017,783**	**106,754**
			2000		
ECAR	510,264	156,683	130,770	212,982	9,829
ERCOT	270,770	102,626	71,699	83,876	12,570
FRCC	182,796	92,391	68,007	16,646	5,752
MAAC	201,993	81,614	78,974	38,760	2,644
MAIN	238,133	72,797	72,929	81,782	10,624
MAPP(U.S.)	137,203	47,583	31,310	54,020	4,291
NPCC(U.S.)	235,445	81,677	92,403	47,275	14,089
SERC	762,609	282,116	202,371	258,562	19,560
SPP	171,474	59,902	52,737	51,730	7,103
WSCC(U.S.)	584,282	201,265	194,506	167,385	21,126
Contiguous U.S.	**3,294,968**	**1,178,655**	**995,705**	**1,013,019**	**107,588**
ASCC	5,310	1,855	2,236	1,037	182
Hawaii[2]	9,272	2,627	2,923	3,667	54
U.S. Total	**3,309,550**	**1,183,137**	**1,000,865**	**1,017,723**	**107,824**

1 Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

2 Sales by NERC region are identified as in the region where a utility's administrative headquarters are located. Therefore, all sales for Citizens Utilities are in NPCC.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 31. Net Summer Capacity at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000

(Megawatts)

North American Electric Reliability Council Region and Hawaii	1996	1997	1998	1999	2000
ECAR	103,360	102,518	101,115	102,942	98,247
ERCOT	53,903	53,711	54,018	54,184	54,322
FRCC	32,751	32,616	34,904	34,980	35,710
MAAC	53,163	53,588	53,168	42,944	11,959
MAIN	52,155	52,093	49,020	35,762	36,487
MAPP(U.S.)	30,610	34,820	34,815	34,813	34,998
NPCC(U.S.)	52,177	51,310	43,166	26,031	22,148
SERC	125,079	155,786	154,320	153,682	157,198
SPP	71,593	42,871	42,669	42,801	43,196
WSCC(U.S.)	131,292	129,232	116,159	107,832	106,635
Contiguous U.S.	**706,083**	**708,641**	**683,451**	**636,068**	**600,996**
ASCC	1,734	1,750	1,721	1,744	1,794
Hawaii	1,610	1,595	1,616	1,608	1,626
U.S. Total	**709,427**	**711,889**	**686,692**	**639,324**	**604,319**

Notes: •Data are final. •The collection of data are as of January 1 of the following year. The 1996 data include the Florida Reliability Coordinating Council created January 1, 1997. The 1997 data include the Entergy Corporation which became part of the SERC from the SPP effective January 1, 1998. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Data for 1998 and beyond: Form EIA-860A, ''Annual Electric Generator Report - Utility''; Data for 1997 and prior: Form EIA-860, ''Annual Electric Generator Report''.

Table 32. Noncoincident Peak Load, Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Actual				
	1996	1997	1998	1999	2000
			Summer		
ECAR	90,798	93,492	93,784	99,239	97,557
ERCOT	47,480	50,541	54,666	55,529	54,817
FRCC	NA	35,375	38,730	37,493	37,728
MAAC	44,302	49,464	48,445	51,645	51,206
MAIN	46,402	45,887	47,509	51,535	51,271
MAPP(U.S.)	28,253	29,787	30,722	31,903	32,899
NPCC(U.S.)	45,094	49,269	49,566	52,855	53,450
SERC	145,650	137,382	143,226	149,012	151,065
SPP	60,072	36,479	37,724	38,609	39,383
WSCC(U.S.)	108,739	110,001	115,921	113,629	116,440
Contiguous U.S.	**616,790**	**637,677**	**660,293**	**681,449**	**685,816**
ASCC	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)
U.S. Total	**616,790**	**637,677**	**660,293**	**681,449**	**685,816**
			Winter		
ECAR	84,534	75,760	84,401	86,239	86,455
ERCOT	38,868	37,966	41,876	39,164	44,287
FRCC	NA	33,076	39,975	40,178	40,894
MAAC	40,468	37,217	36,532	40,220	43,139
MAIN	37,162	34,973	37,410	39,081	39,742
MAPP(U.S.)	24,251	25,390	26,080	25,200	27,363
NPCC(U.S.)	41,208	41,338	44,119	45,227	45,170
SERC	143,060	122,649	127,416	128,563	134,488
SPP	49,095	27,437	27,847	27,963	28,375
WSCC(U.S.)	95,435	94,158	101,822	99,080	102,435
Contiguous U.S.	**554,081**	**529,874**	**567,558**	**570,915**	**592,348**
ASCC	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)
U.S. Total	**554,081**	**529,874**	**567,558**	**570,915**	**592,348**

See footnotes at end of table.

Table 32. Noncoincident Peak Load, Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000 (Continued)
(Megawatts)

North American Electric Reliability Council Region and Hawaii	Projected				
	2001	2002	2003	2004	2005
			Summer		
ECAR	102,161	104,081	106,130	107,964	109,905
ERCOT	56,759	58,608	60,130	61,769	63,480
FRCC	38,478	39,548	40,783	41,714	42,644
MAAC	52,977	53,753	54,644	55,501	56,412
MAIN	55,368	56,416	57,055	58,106	59,157
MAPP(U.S.)	29,814	30,304	30,865	31,404	31,930
NPCC(U.S.)	54,270	55,283	56,107	56,884	57,694
SERC	159,930	163,742	166,686	169,752	173,496
SPP	40,522	41,099	41,949	42,885	43,932
WSCC(U.S.)	118,887	121,407	123,946	126,534	129,199
Contiguous U.S.	**709,166**	**724,241**	**738,295**	**752,513**	**767,849**
ASCC	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)
U.S. Total	**709,166**	**724,241**	**738,295**	**752,513**	**767,849**
			Winter		
ECAR	90,041	91,684	93,170	94,689	95,601
ERCOT	44,394	46,004	47,460	48,906	50,375
FRCC	42,208	43,508	44,487	45,461	46,454
MAAC	43,809	44,462	45,077	45,724	46,368
MAIN	43,663	43,857	44,691	44,585	45,302
MAPP(U.S.)	24,661	25,083	25,468	25,857	26,288
NPCC(U.S.)	45,650	46,388	47,120	47,846	48,498
SERC	139,459	141,809	144,436	147,592	151,029
SPP	29,804	30,132	30,789	31,509	32,150
WSCC(U.S.)	102,237	104,173	106,333	108,339	110,458
Contiguous U.S.	**605,926**	**617,100**	**629,031**	**640,508**	**652,523**
ASCC	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)
U.S. Total	**605,926**	**617,100**	**626,395**	**640,508**	**652,523**

(1) Data for ASCC (Alaska) were not filed beginning in 1996.
(2) Data for Hawaii are not submitted on this form.

Notes: •Actual data are final. •Projected data are updated annually. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of indepent rounding. •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 2000 begins December 1, 2000, and extends through March 31, 2001. Thus, the winter referred to here would be the winter of 2000/2001.

Sources: Form EIA-411, ''Coordinated Bulk Power Supply Program.''

Table 33. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts	Purchased Power	Exchange Received	Wheeling Received
		1996		
ECAR	264,825	203,637	1,361	59,827
ERCOT	148,971	73,590	55,354	20,027
FRCC	—	—	—	—
MAAC	141,448	120,701	474	20,272
MAIN	75,234	67,287	252	7,695
MAPP(U.S.)	124,893	102,960	4,189	17,744
NPCC(U.S.)	276,773	209,271	3,799	63,703
SERC	454,193	384,930	31,998	37,264
SPP	198,090	166,768	5,340	25,982
WSCC(U.S.)	574,451	358,142	51,859	164,449
Contiguous U.S.	2,258,877	1,687,286	154,627	416,964
ASCC	4,257	3,338	99	820
Hawaii	3,572	3,568	4	0
U.S. Total	2,266,707	1,694,192	154,731	417,784
		1997		
ECAR	319,495	259,081	1,764	58,650
ERCOT	134,715	78,170	56,545	0
FRCC	50,820	40,140	33	10,647
MAAC	151,729	135,582	518	15,629
MAIN	105,159	88,743	294	16,121
MAPP(U.S.)	132,758	108,253	3,814	20,691
NPCC(U.S.)	290,015	201,349	4,879	83,786
SERC	425,460	343,939	29,589	51,932
SPP	210,562	169,136	9,780	31,645
WSCC(U.S.)	645,818	446,733	47,919	151,166
Contiguous U.S.	2,466,530	1,871,127	155,135	440,268
ASCC	4,267	3,348	79	840
Hawaii	3,627	3,625	2	0
U.S. Total	2,474,424	1,878,099	155,217	441,108
		1998		
ECAR	350,223	276,928	6,974	66,322
ERCOT	137,785	82,765	54,389	631
FRCC	67,693	55,730	42	11,921
MAAC	158,175	145,124	733	12,318
MAIN	117,000	88,766	570	27,664
MAPP(U.S.)	136,784	109,152	4,222	23,409
NPCC(U.S.)	272,560	209,550	4,798	58,212
SERC	532,068	434,074	19,662	78,332
SPP	110,978	84,182	5,229	21,568
WSCC(U.S.)	622,881	433,920	36,989	151,972
Contiguous U.S.	2,506,147	1,920,191	133,607	452,350
ASCC	4,064	3,570	115	379
Hawaii	3,440	3,437	3	0
U.S. Total	2,513,651	1,927,198	133,725	452,728

See footnotes at end of table.

Table 33. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts	Purchased Power	Exchange Received	Wheeling Received
	1999			
ECAR	337,502	265,186	1,326	70,991
ERCOT	120,461	84,138	35,991	[1] 631
FRCC	73,564	57,944	27	15,592
MAAC	136,548	122,286	3,419	10,843
MAIN	102,812	72,580	577	29,654
MAPP(U.S.)	141,133	109,527	3,505	28,101
NPCC(U.S.)	323,278	229,339	4,031	89,909
SERC	531,326	435,424	25,258	70,644
SPP	120,514	87,651	4,586	28,277
WSCC(U.S.)	669,330	478,550	34,162	156,618
Contiguous U.S.	**2,556,468**	**1,942,625**	**112,882**	**500,961**
ASCC	3,840	3,562	108	170
Hawaii	3,394	3,387	6	0
U.S. Total	**2,563,702**	**1,949,574**	**112,997**	**501,131**
	2000			
ECAR	417,395	332,295	1,926	83,175
ERCOT	135,505	93,877	41,603	[1] 25
FRCC	82,600	66,269	23	16,308
MAAC	193,954	178,728	6,623	8,603
MAIN	178,319	121,057	565	56,697
MAPP(U.S.)	133,895	108,307	3,817	21,771
NPCC(U.S.)	399,947	271,363	5,812	122,771
SERC	591,578	467,047	25,833	98,698
SPP	143,514	94,859	5,226	43,429
WSCC(U.S.)	715,248	509,865	44,062	161,321
Contiguous U.S.	**2,991,955**	**2,243,667**	**135,491**	**612,797**
ASCC	3,842	3,142	105	595
Hawaii	3,572	3,572	0	0
U.S. Total	**2,999,369**	**2,250,382**	**135,595**	**613,392**

[1] ''Wheeling Received'' and ''Wheeling Delivered'' for ERCOT in 1997, 1998, 1999, and 2000 reflect enactment by the Public Utility Commission of Texas (the Commission) of Substantive Rule 23.67 (''Open-access Comparable Transmission Service''), effective on September 12, 1996. SR 23.67 governs virtually all phases of transmission access in Texas and requires that wheeling services, provided by transmission facility operators under the jurisdiction of the Commission, shall be reimbursed using the vector-absolute, megawatt/mile method. This method derives reimbursement rates utilizing information on the total line-mileage under load, the maximum load in megawatts, and the fee per megawatt-mile. Use of this method does not require transmission service providers to measure energy flows.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 34. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1996		
ECAR	274,275	213,373	1,381	59,522
ERCOT	115,163	39,924	55,230	20,009
FRCC	—	—	—	—
MAAC	93,421	73,221	22	20,177
MAIN	69,301	61,421	330	7,550
MAPP(U.S.)	104,835	82,899	5,479	16,457
NPCC(U.S.)	201,223	135,832	1,991	63,400
SERC	429,948	352,216	42,307	35,425
SPP	174,435	143,548	5,017	25,870
WSCC(U.S.)	541,181	325,405	54,546	161,230
Contiguous U.S.	**2,003,783**	**1,427,839**	**166,304**	**409,640**
ASCC	4,257	3,340	97	820
Hawaii	7	0	7	0
U.S. Total	**2,008,047**	**1,431,179**	**166,407**	**410,460**
		1997		
ECAR	329,876	269,688	1,782	58,406
ERCOT	96,812	40,346	56,467	0
FRCC	37,627	27,182	19	10,426
MAAC	108,060	92,418	16	15,626
MAIN	83,187	66,939	331	15,918
MAPP(U.S.)	112,294	89,619	3,306	19,370
NPCC(U.S.)	215,175	128,369	3,315	83,491
SERC	431,021	336,819	44,850	49,352
SPP	183,461	141,120	10,656	31,685
WSCC(U.S.)	621,041	420,704	51,476	148,860
Contiguous U.S.	**2,218,554**	**1,613,202**	**172,219**	**433,133**
ASCC	4,037	3,115	82	840
Hawaii	4	0	4	0
U.S. Total	**2,222,596**	**1,616,318**	**172,305**	**433,973**
		1998		
ECAR	347,326	275,006	7,043	65,277
ERCOT	98,143	42,958	54,570	[1] 0
FRCC	47,955	36,226	56	11,673
MAAC	131,873	119,627	13	12,233
MAIN	99,397	71,254	618	27,525
MAPP(U.S.)	117,460	92,457	3,623	21,380
NPCC(U.S.)	188,205	126,177	4,127	57,902
SERC	503,114	399,718	26,469	76,927
SPP	115,035	88,547	5,051	21,438
WSCC(U.S.)	591,499	409,307	32,888	149,304
Contiguous U.S.	**2,240,008**	**1,661,277**	**134,458**	**444,274**
ASCC	3,301	2,803	119	379
Hawaii	6	0	6	0
U.S. Total	**2,243,316**	**1,664,081**	**134,583**	**444,652**

See footnotes at end of table.

Table 34. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1999		
ECAR	324,482	252,377	1,437	70,668
ERCOT	78,721	41,992	36,675	[1] 615
FRCC	51,856	36,505	24	15,327
MAAC	129,074	118,311	5	10,758
MAIN	94,847	64,279	1,010	29,559
MAPP(U.S.)	124,835	96,041	3,063	25,731
NPCC(U.S.)	201,577	108,857	3,016	89,704
SERC	492,886	398,431	25,910	68,545
SPP	123,909	91,299	4,576	28,035
WSCC(U.S.)	614,319	424,720	35,380	154,219
Contiguous U.S.	**2,236,507**	**1,632,810**	**111,096**	**492,601**
ASCC	3,086	2,804	111	170
Hawaii	2	0	2	0
U.S. Total	**2,239,595**	**1,635,614**	**111,210**	**492,771**
		2000		
ECAR	396,250	311,765	1,541	82,944
ERCOT	83,943	42,081	41,847	[1] 16
FRCC	54,888	38,849	31	16,008
MAAC	106,304	97,755	37	8,512
MAIN	132,331	75,184	569	56,579
MAPP(U.S.)	119,124	95,548	3,286	20,291
NPCC(U.S.)	257,164	132,007	2,836	122,321
SERC	529,443	409,648	23,871	95,924
SPP	140,082	91,915	5,029	43,138
WSCC(U.S.)	625,580	418,224	47,890	159,466
Contiguous U.S.	**2,445,109**	**1,712,975**	**126,936**	**605,199**
ASCC	3,305	2,608	103	595
Hawaii	0	0	0	0
U.S. Total	**2,448,415**	**1,715,582**	**127,039**	**605,794**

[1] ''Wheeling Received'' and ''Wheeling Delivered'' for ERCOT in 1997, 1998, 1999, and 2000 reflect enactment by the Public Utility Commission of Texas (the Commission) of Substantive Rule 23.67 (''Open-access Comparable Transmission Service''), effective on September 12, 1996. SR 23.67 governs virtually all phases of transmission access in Texas and requires that wheeling services, provided by transmission facility operators under the jurisdiction of the Commission, shall be reimbursed using the vector-absolute, megawatt/mile method. This method derives reimbursement rates utilizing information on the total line-mileage under load, the maximum load in megawatts, and the fee per megawatt-mile. Use of this method does not require transmission service providers to measure energy flows.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding. •This is a summation of utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, export, and nonutility transactions.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 35. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1996	
ECAR	–9,450	264,825	274,275
ERCOT	33,808	148,971	115,163
FRCC	—	—	—
MAAC	48,027	141,448	93,421
MAIN	5,933	75,234	69,301
MAPP(U.S.)	20,058	124,893	104,835
NPCC(U.S.)	75,550	276,773	201,223
SERC	24,245	454,193	429,948
SPP	23,655	198,090	174,435
WSCC(U.S.)	33,270	574,451	541,181
Contiguous U.S.	**255,095**	**2,258,877**	**2,003,783**
ASCC	0	4,257	4,257
Hawaii	3,565	3,572	7
U.S. Total	**258,660**	**2,266,707**	**2,008,047**
		1997	
ECAR	–10,381	319,495	329,876
ERCOT	37,903	134,715	96,812
FRCC	13,192	50,820	37,627
MAAC	43,669	151,729	108,060
MAIN	21,971	105,159	83,187
MAPP(U.S.)	20,463	132,758	112,294
NPCC(U.S.)	74,840	290,015	215,175
SERC	–5,561	425,460	431,021
SPP	27,101	210,562	183,461
WSCC(U.S.)	24,778	645,818	621,041
Contiguous U.S.	**247,976**	**2,466,530**	**2,218,554**
ASCC	230	4,267	4,037
Hawaii	3,623	3,627	4
U.S. Total	**251,828**	**2,474,424**	**2,222,596**
		1998	
ECAR	2,897	350,223	347,326
ERCOT	39,642	137,785	98,143
FRCC	19,738	67,693	47,955
MAAC	26,302	158,175	131,873
MAIN	17,603	117,000	99,397
MAPP(U.S.)	19,324	136,784	117,460
NPCC(U.S.)	84,355	272,560	188,205
SERC	28,954	532,068	503,114
SPP	–4,057	110,978	115,035
WSCC(U.S.)	31,382	622,881	591,499
Contiguous U.S.	**266,139**	**2,506,147**	**2,240,008**
ASCC	763	4,064	3,301
Hawaii	3,434	3,440	6
U.S. Total	**270,336**	**2,513,651**	**2,243,316**

See footnotes at end of table.

Table 35. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1999	
ECAR	13,020	337,502	324,482
ERCOT	41,740	120,461	78,721
FRCC	21,708	73,564	51,856
MAAC	7,474	136,548	129,074
MAIN	7,964	102,812	94,847
MAPP(U.S.)	16,298	141,133	124,835
NPCC(U.S.)	121,701	323,278	201,577
SERC	38,440	531,326	492,886
SPP	–3,395	120,514	123,909
WSCC(U.S.)	55,011	669,330	614,319
Contiguous U.S.	**319,961**	**2,556,468**	**2,236,507**
ASCC	755	3,840	3,086
Hawaii	3,392	3,394	2
U.S. Total	**324,108**	**2,563,702**	**2,239,595**
		2000	
ECAR	33,714	574,584	540,871
ERCOT	63,045	1,218,053	1,155,008
FRCC	27,767	82,655	54,888
MAAC	92,423	681,425	589,002
MAIN	49,209	183,726	134,516
MAPP(U.S.)	17,036	157,152	140,116
NPCC(U.S.)	155,164	678,783	523,619
SERC	66,644	1,051,230	984,586
SPP	3,429	472,310	468,881
WSCC(U.S.)	104,999	878,079	773,080
Contiguous U.S.	**613,431**	**5,977,997**	**5,364,566**
ASCC	537	3,842	3,305
Hawaii	3,572	3,572	0
U.S. Total	**617,540**	**5,985,411**	**5,367,872**

1 Equals receipts minus deliveries.
2 Equals purchased power plus exchange received plus wheeling received and imports.
3 Equals sales for resale plus exchange delivered plus wheeling delivered and exports.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding. •This is a summation of all utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, import, and nonutility transactions.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 36. U.S. Electric Utility Purchases of Nonutility Generated Electricity by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1996	1997	1998	1999	2000 [1]
ECAR	15,861	15,989	14,692	15,113	–-
ERCOT	23,916	25,908	26,562	22,159	–-
FRCC	—	11,824	13,254	16,591	–-
MAAC	23,892	24,019	24,360	25,079	–-
MAIN	468	971	3,348	2,161	–-
MAPP(U.S.)	706	1,053	1,863	2,834	–-
NPCC(U.S.)	56,207	58,858	63,557	72,241	–-
SERC	31,276	15,324	17,289	20,432	–-
SPP	6,090	5,130	484	4,527	–-
WSCC(U.S.)	67,028	80,502	89,372	130,866	–-
Contiguous U.S.	**225,445**	**239,577**	**254,779**	**312,003**	**–-**
ASCC	5	10	317	366	–-
Hawaii	3,568	3,625	3,437	3,387	–-
U.S. Total	**229,018**	**243,213**	**258,534**	**315,757**	**–-**

[1] Data on purchases from nonutilities were not collected on the Form EIA-861.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 37. Net Internal Demand, Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region and Hawaii, 2001 Through 2005
(Megawatts)

North American Electric Reliability Council Region and Hawaii	2001			2002		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	98,651	115,379	14.5	100,465	114,151	12.0
ERCOT	53,649	69,622	23.0	57,001	79,782	28.5
FRCC	35,666	43,083	17.2	36,779	44,317	17.0
MAAC	51,358	60,679	15.4	52,134	65,823	20.8
MAIN	51,845	64,170	19.2	52,827	67,964	22.3
MAPP(U.S)	28,006	34,236	18.2	28,418	34,175	16.8
NPCC(U.S)	54,270	63,376	14.4	55,283	68,793	19.6
SERC	151,527	169,760	10.7	155,329	176,234	11.9
SPP	39,056	46,109	15.3	39,482	46,098	14.4
WSCC(U.S)	116,913	141,640	17.5	120,116	150,068	20.0
Contiguous U.S	**680,941**	**808,054**	**16.5**	**697,834**	**847,405**	**18.3**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**680,941**	**808,054**	**16.5**	**697,834**	**847,405**	**18.3**
	2003			**2005**		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	102,489	114,993	10.9	106,213	117,950	10.0
ERCOT	58,514	81,544	28.2	61,827	83,242	25.7
FRCC	38,015	46,275	17.8	39,898	49,119	18.8
MAAC	53,025	74,639	29.0	54,793	83,450	34.3
MAIN	53,569	69,409	22.8	55,656	70,896	21.5
MAPP(U.S)	28,914	34,276	15.6	29,892	34,402	13.1
NPCC(U.S)	56,107	69,343	19.1	57,694	73,945	22.0
SERC	158,685	179,848	11.8	165,476	189,877	12.9
SPP	40,311	47,097	14.4	42,279	47,684	11.3
WSCC(U.S)	122,648	159,624	23.2	127,895	187,209	31.7
Contiguous U.S	**712,277**	**877,048**	**19.4**	**741,623**	**937,774**	**20.1**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**712,277**	**877,048**	**19.5**	**741,623**	**937,774**	**20.1**
	2001			**2002**		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Winter					
ECAR	87,190	119,870	27.3	88,904	118,958	25.3
ERCOT	41,606	72,597	42.7	44,868	80,751	44.4
FRCC	38,199	45,665	16.3	39,492	48,425	18.4
MAAC	43,110	64,854	33.5	43,763	73,261	40.3
MAIN	41,250	63,075	34.6	41,470	67,853	38.9
MAPP(U.S)	23,748	32,777	27.5	24,145	33,475	27.9
NPCC(U.S)	45,650	68,173	33.0	46,388	71,790	35.4
SERC	131,779	169,850	22.4	133,714	174,815	23.5
SPP	28,761	45,501	36.8	28,942	45,494	36.4
WSCC(U.S)	101,270	144,185	29.8	103,401	155,918	33.7
Contiguous U.S	**582,563**	**826,547**	**30.4**	**595,087**	**870,740**	**32.4**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**582,563**	**826,547**	**30.4**	**595,087**	**870,740**	**32.4**

See footnotes at end of table.

Table 37. Net Internal Demand, Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region and Hawaii, 2001 Through 2005 (Continued)
(Megawatts)

North American Electric Reliability Council Region and Hawaii	2003			2005		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Winter					
ECAR	90,451	119,832	24.5	92,872	123,110	24.6
ERCOT	46,309	82,060	43.6	49,221	83,761	41.2
FRCC	40,474	49,924	18.9	42,425	53,024	20.0
MAAC	44,378	82,693	46.3	45,669	88,433	48.4
MAIN	42,144	69,344	39.2	43,533	70,136	37.9
MAPP(U.S)	24,506	34,034	28.0	25,223	33,628	25.0
NPCC(U.S)	47,120	72,540	35.0	48,498	77,539	37.5
SERC	136,544	178,650	23.6	143,078	192,633	25.7
SPP	29,584	46,664	36.6	30,941	47,671	35.1
WSCC(U.S)	105,553	173,147	39.0	109,670	192,723	43.1
Contiguous U.S	**607,063**	**908,888**	**33.5**	**631,130**	**962,658**	**33.9**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**607,063**	**908,888**	**33.5**	**631,130**	**962,658**	**33.9**

(1) Data for ASCC (Alaska) were not filed.
(2) Data for Hawaii are not submitted on this form.
Notes: •Data are projected and updated annually. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding. •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 2000 begins December 1, 2000, and extends through March 31, 2001. Thus, the winter referred to here would be the winter of 2000/2001.
Source: Form EIA-411, ''Coordinated Bulk Power Supply Program''.

U.S. Electric Utility Demand-Side Management

U.S. electric utilities have come to realize that a flexible and diverse management strategy provides the greatest opportunity for success in the competitive and uncertain environment in which they operate. An important component of this strategy has been the reliance on demand-side management (DSM) programs to modify the growth in demand for energy use, to cost-effectively meet customer energy service requirements, to selectively expand customer services, and to optimize the use of generating resources. This chapter provides a brief description of the key elements of electric utility DSM programs in the United States.

Background

DSM consists of electric utilities planning, implementing, and monitoring activities that are designed to encourage consumers to modify their level and pattern of electricity usage. In the past, the primary objective of most DSM programs was to provide cost-effective energy and capacity resources to help defer the need for new sources of power, including generating facilities, power purchases, and transmission and distribution capacity additions. However, due to changes that are occurring within the industry, electric utilities are also using DSM as a way to enhance customer service.

In States that are affected by deregulation, and competition, a number of different strategies have been undertaken. Strategies such as:

- energy service companies (ESCO's) that have been created as non-regulated entities by electric utilities. ESCO's are designed to help consumers reduce the energy related charges.
- an increase in customer service programs as a way to keep current customers, and attract new customers. For residential customers, this includes offering energy efficiency programs, that will help to reduce consumer costs. For larger commercial and industrial customers, this has included offering interruptible rates, as well as other ways to reduce electricity costs.
- State energy efficiency utilities or organizations have been created in Vermont, California, and New York. These utilities are designed to centralize and simplify energy efficiency and load management programs.

In many states DSM programs are still a key component of the integrated resource plans (IRP) of a number of electric utilities. The IRP process differs from traditional utility planning practices primarily in its increased attention to DSM programs and its integration of supply- and demand-side resources into a flexible resource portfolio. Utilities and some State regulatory commissions use the IRP process to assess a variety of resource options that meet consumer energy-service requirements, while being responsive to external changes such as economic conditions, resource prices, new technologies, and changes in regulatory and tax policy. In addition to balanced consideration of supply- and demand-side options, the IRP process includes consideration of risk and diversity of supply, maintenance of system reliability, and in some instances the application of specific values to reflect environmental and other external impacts.

Identify Program Alternatives

The types of DSM programs that utilities select to alter the timing and level of demand for electricity varies depending on their overall organization and market environment, strategic objectives, and system operating characteristics. DSM programs generally promote one of three basic objectives that differ in their intended effects on electricity use (measured in kilowatthours) and demand (measured in kilowatts); energy efficiency, load management, and load shifting.

Energy efficiency or conservation programs are aimed at reducing the energy used by promoting high-efficiency equipment and building design. Such high-efficiency measures generally use less electricity to provide consumers an equivalent or greater level of electric energy services (light, heat, cooling, or drive power).

Load management programs are aimed at reducing demand at certain critical times (such as summer or winter peak) and usually have only a minor effect on annual energy consumption. For example, residential and commercial air conditioners or water heaters may be allowed to operate unimpeded during off-peak demand hours, but are cycled on and off by the utility during a few peak-demand hours.

Flexible load shape programs give consumers the incentive to alter their consumption in response to changes in the utility's cost of providing power. Real time pricing is an example of this type of program.

Planning and Selection of Programs

The main elements of the DSM program planning and selection process are to evaluate consumer characteristics that influence the acceptance of DSM programs and utility considerations affecting resource requirements and the cost of alternative resource options. Among the consumers' characteristics that influence a program's success are demographics, income, knowledge and awareness, attitude and motivation, and discount rate. External influences such as economic conditions, energy prices, technologies, regulation, and tax credits also influence consumer's decisions regarding fuel and appliance choice, efficiency, and use. The utility's considerations are usually focused on the interaction of load shape changes and supply-side resource options, transmission and distribution effects, and regulatory compliance.

The inclusion of environmental externalities in planning generally affects DSM options favorably. For example, if only traditional costs are considered in the planning process, a supply-side option might appear more attractive than a particular energy efficiency program.

However, traditional costs seldom reflect the full cost to society of utility activities that adversely affect the environment. In assessing supply-side and demand-side options for planning purposes, regulators have been moving to consider broad impacts of utility resource acquisition on society, including environmental and other externalities. Environmental externalities are real impacts on the production or utility functions of others, including impacts on health and property values which are not reflected in the prices of goods and services.[12] Under traditional command-and-control air quality regulation, the additional emissions associated with operating a polluting facility for more hours do not increase the production costs of the source. Thus, many residual air emissions are classified as externalities. Externalities also may include foreign oil or transition costs associated with local economic dislocations. Environmental externalities have become a part of the criteria for comparison and selection of utility resource options in 26 States and the District of Columbia.[13]

Data Sources

The data in the following tables were collected on Schedule V, "Demand-Side Management Information" of the 2000 Form EIA-861,"Annual Electric Utility Report." Schedule V collects utility information on actual and potential peak load reductions and energy savings for two program categories: Energy Efficiency and Load Management programs, by four major consumer sectors (residential, commercial, industrial, and other). Utilities provide information for the reporting year 2000.

Both annual and incremental energy savings and peak load reductions are collected for the reporting year. Annual effects are the total effects in energy use and peak load caused by all new and prior-year participants in the DSM programs that are in place during a given year. It includes all participants in existing and new programs (those implemented during the given year). Incremental effects are the annual effects in energy use and peak load caused by new participants in DSM programs during a given year. Incremental effects are annualized to indicate the program effects that would have occurred had these participants been in the program on January 1 of the given year. DSM costs are reported in one of two categories. If the cost can be tracked to a specific program category (energy efficiency, or load management), it is reported as a direct utility cost under that program category. If the cost cannot be tracked to a program category, it is reported as an indirect utility cost.

[12] William J. Baumol and Wallace E. Oates, *The Theory of Environmental Policy*, 2nd Ed., (Cambridge University Press, New York, 1989) p. 17.

[13] The Consumer Energy Council of America Research Foundation, *Incorporating Environmental Externalities into Utility Planning* (Washington, D.C., 1993).

Why the Numbers are Changing

Fluctuations in energy savings can be directly attributed to changes in New England, and California. In California, the California Board for Energy Efficiency (CBEE) was created to fund energy efficiency programs that had previously been funded by electric utilities. However, on the EIA-861 survey, utilities in California have begun reporting the cost associated with the CBEE, as well as the energy savings resulting from these programs. In Vermont and New York, utilities have taken the opposite approach. They are no longer reporting the costs and energy savings resulting from state run programs.

The lack of major changes in potential peak load reductions continues to be an expected result. A number of utilities continue to offer their interruptible and time-of-use rates to their commercial and industrial customers. However, there have been major reductions in the installation of residential peak load shaving programs. Factors other than restructuring such as weather variations, can influence fluctuations in actual peak load reductions.

Reminder: It is no longer possible to directly compare 1998 through 2000 with prior years as the threshold for small and large utilities was changed. Small utilities beginning in 1998 are classified as having sales for resales, and sales to ultimate consumers of less than 150 million kilowatthours. For 1997 and prior years, small utilities were classified as having sales for resale and sales to ultimate consumers of less than 120 million kilowatthours.

Table 38. U.S. Electric Utility Demand-Side Management Program Energy Savings, Actual and Potential Peak Load Reductions, and Cost, 1996 Through 2000

Item	1996	1997	1998	1999	2000
Energy Savings (million kilowatthours)[1]	61,842	56,406	49,167	50,563	53,701
Actual Peak Load Reductions (megawatts)[2]	29,893	25,284	27,231	26,455	22,901
Potential Peak Load Reductions (megawatts)	48,344	41,237	41,430	43,570	41,369
Cost (thousand dollars)[3]	1,902,197	1,636,020	1,420,920	1,423,644	1,564,901

1 Represents the total annual effects caused by all participants in demand-side management programs in effect during a given year. Included are new and existing participants in existing programs (those implemented in prior years that are in place during the reporting year) and all participants in new programs (those implemented during the reporting year).

2 Represents the actual reduction in annual peak load achieved by consumers, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Reduction).

3 Data represent the sum of the direct and indirect utility costs for the year and reflect the total cash expenditures incurred for the year, reported in nominal dollars, that flowed out to support demand-side management programs. Nonutility costs are excluded.

Notes: •Data are final. •Data for 1998 through 2000 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours, and for prior years greater than or equal to 120 million kilowatthours.

Source: Energy Information Administration, Form EIA-861, ‘‘Annual Electric Utility Report.’’

Table 39. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1996 through 2000

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Total Actual Peak Load Reduction	Direct Load Control	Interruptible Load	Energy Efficiency	Other Load Management	Other Demand-Side Management
				1996		
ECAR	2,547	398	1,129	852	103	64
ERCOT	2,002	27	91	1,571	309	4
FRCC	—	—	—	—	—	—
MAAC	1,773	230	167	936	426	15
MAIN	1,625	42	790	697	84	12
MAPP(U.S.)	3,106	1,205	853	797	235	15
NPCC(U.S.)	2,554	79	230	2,219	18	9
SERC	10,203	3,221	2,793	3,468	508	212
SPP	924	165	387	176	182	13
WSCC(U.S.)	5,134	206	945	3,517	405	62
Contiguous U.S.	**29,869**	**5,573**	**7,387**	**14,233**	**2,270**	**405**
ASCC	7	3	3	2	0	0
Hawaii	17	0	0	8	8	1
U.S. Total	**29,893**	**5,575**	**7,390**	**14,243**	**2,278**	**407**

See footnotes at end of table.

Table 39. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1996 Through 2000 (Continued)

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Total Actual Peak Load Reduction	Energy Efficiency	Load Management
	1997		
ECAR	1,239	418	821
ERCOT	1,699	1,593	106
FRCC	3,439	1,909	1,531
MAAC	1,548	1,028	520
MAIN	1,390	377	1,013
MAPP(U.S.)	2,502	902	1,600
NPCC(U.S.)	2,586	2,287	299
SERC	6,043	1,671	4,372
SPP	709	215	493
WSCC(U.S.)	4,108	2,917	1,190
Contiguous U.S.	**25,263**	**13,318**	**11,945**
ASCC	7	1	6
Hawaii	14	1,239	7
U.S. Total	**25,284**	**13,326**	**11,958**
	Total Actual Peak Load Reduction	**Energy Efficiency**	**Load Management**
	1998		
ECAR	1,624	487	1,137
ERCOT	2,144	2,052	92
FRCC	3,983	2,109	1,874
MAAC	1,569	1,106	463
MAIN	2,890	1,373	1,517
MAPP(U.S.)	3,081	956	2,125
NPCC(U.S.)	2,270	1,977	293
SERC	4,329	1,123	3,205
SPP	816	158	658
WSCC(U.S.)	4,477	2,234	2,244
Contiguous U.S.	**27,184**	**13,576**	**13,608**
ASCC	5	1	4
Hawaii	41	13	28
U.S. Total	**27,231**	**13,591**	**13,640**
	Total Actual Peak Load Reduction	**Energy Efficiency**	**Load Management**
	1999		
ECAR	1,716	550	1,166
ERCOT	1,931	1,795	136
FRCC	4,452	2,253	2,200
MAAC	1,518	1,105	413
MAIN	3,274	1,849	1,424
MAPP(U.S.)	3,354	1,017	2,336
NPCC(U.S.)	1,063	973	90
SERC	4,120	1,030	3,090
SPP	651	86	565
WSCC(U.S.)	4,342	2,784	1,557
Contiguous U.S.	**26,420**	**13,442**	**12,978**
ASCC	5	2	4
Hawaii	29	8	21
U.S. Total	**26,455**	**13,452**	**13,003**

See footnotes at end of table.

Table 39. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1996 Through 2000 (Continued)

(Megawatts)¬Continued

	Total Actual Peak Load Reduction	Energy Efficiency	Load Management
	2000		
ECAR	1,054	493	561
ERCOT	1,992	1,896	96
FRCC	4,119	2,364	1,755
MAAC	1,533	1,127	406
MAIN	1,372	912	460
MAPP(U.S.)	3,096	983	2,113
NPCC(U.S.)	1,114	967	146
SERC	2,269	1,093	1,176
SPP	566	101	465
WSCC(U.S.)	5,750	2,926	2,824
Contiguous U.S.	**22,864**	**12,863**	**10,002**
ASCC	5	2	4
Hawaii	31	9	22
U.S. Total	**22,901**	**12,873**	**10,027**

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Data for 1998 through 2000 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours, and for prior years greater than or equal to 120 million kilowatthours. •These data reflect actual real changes in the demand for electricity at the time of annual peak load, as opposed to the installed peak load reduction capability (i.e., potential peak load reduction), achieved by all program participants during the reporting year.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 40. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Program Category, 2000

Program	Actual Peak Load Reductions[1] (megawatts)	Potential Peak Load Reductions[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Energy Efficiency[5]	12,873	12,873	52,827
Load Management[3]	10,027	28,495	875
U.S. Total	**22,901**	**41,369**	**53,701**
	Incremental Effects[6]		
Large Utilities[4]			
Energy Efficiency[5]	720	720	3,284
Load Management[3]	919	2,439	63
Total	**1,640**	**3,159**	**3,347**
Small Utilities[7]			
Energy Efficiency[5]	25	25	8
Load Management[3]	137	190	9
Total	**162**	**215**	**17**
U.S. Total	**1,801**	**3,374**	**3,364**

1 Represents the reduction in annual peak load achieved by consumers, at the time of annual peak load .

2 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.

3 Represents the total effects caused by all participants in demand-side management programs in effect during a given year. Included are new and existing participants in existing programs (those implemented in prior years that are in place during the reporting year) and all participants in new programs (those implemented during the reporting year).

4 Refers to electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours.

5 Includes programs aimed at reducing energy consumption over many hours during the year. These programs reduce load and if they coincide with periods of peak usage they are included in the actual peak load reduction. However, these programs cannot be implemented specifically at the time of peak usage.

6 Represents the total effects caused by new participants in existing demand-side management programs and all participants in new programs during the year. Incremental effects are annualized to indicate the program effects that would have resulted had participants been initiated into the program on January 1 of the reporting year.

7 Refers to electric utilities with sales to ultimate consumers and sales for resale less than 150 million kilowatthours.

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

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 41. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Sector, 2000

Sector	Actual Peak Load Reductions[1] (megawatts)	Potential Peak Load Reductions[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Residential	9,446	12,970	16,288
Commercial	6,987	9,114	25,660
Industrial	6,141	18,775	9,160
Other	327	510	2,593
U.S. Total	**22,901**	**41,368**	**53,701**
	Incremental Effects[3]		
Large Utilities[4]			
Residential	572	699	856
Commercial	515	565	1,780
Industrial	502	1,815	547
Other	50	79	164
Total	1,640	**3,159**	**3,347**
Small Utilities[5]			
Residential	37	55	9
Commercial	37	51	4
Industrial	62	64	1
Other	26	44	3
Total	**162**	**215**	**17**
U.S. Total	**1,801**	**3,374**	**3,365**

1 Represents the reduction in annual peak load achieved by consumers, at the time of annual peak load .
2 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.
3 Represents the total effects caused by all participants in demand-side management programs in effect during 2000. Included are new and existing participants in existing programs (those implemented in prior years that were in place during 2000) and all participants in new programs (those implemented during 2000).
4 Refers to electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours.
5 Refers to electric utilities with sales to ultimate consumers and sales for resale less than 150 million kilowatthours.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 42. U.S. Electric Utility Demand-Side Management Energy Savings by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Historical Savings				
	1996	1997	1998	1999	2000
ECAR	3,695	1,984	2.311	2,199	1,805
ERCOT	3,866	3,530	3,690	3,875	4,158
FRCC	–-	5,418	5,839	6,143	6,386
MAAC	3,620	4,003	4,531	4,780	5,492
MAIN	3,007	1,429	3,233	3,046	3,714
MAPP(U.S.)	3,153	3,442	3,546	4,548	4,224
NPCC(U.S.)	10,022	9,125	6,928	4,131	4,920
SERC	10,404	4,588	4,148	3,157	3,655
SPP	358	253	240	198	330
WSCC(U.S.)	23,663	22,570	14,575	18,374	18,897
Contiguous U.S.	**61,789**	**56,342**	**49,041**	**50,451**	**53,581**
ASCC	5	9	7	7	8
Hawaii	49	55	119	105	113
U.S. Total	**61,842**	**56,406**	**49,167**	**50,563**	**53,701**

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding. •Data for 1998 through 2000 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours, and for prior years greater than or equal to 120 million kilowatthours.
Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 43. U.S. Electric Utility Demand-Side Management Cost by North American Electric Reliability Council Region and Hawaii, 1996 Through 2000
(Thousand Dollars)

North American Electric Reliability Council Region and Hawaii	Existing				
	1996	1997	1998	1999	2000
ECAR	77,031	37,270	28,406	26,274	22,425
ERCOT	54,120	41,839	30,158	28,022	26,428
FRCC	--	267,738	268,565	249,759	251,569
MAAC	225,253	184,125	207,803	184,094	184,392
MAIN	70,350	50,513	77,361	105,596	120,411
MAPP(U.S.)	156,688	125,804	129,462	120,772	99,331
NPCC(U.S.)	263,160	272,144	185,970	149,552	280,495
SERC	551,038	245,385	175,585	158,993	155,545
SPP	28,385	18,751	33,289	5,630	11,606
WSCC(U.S.)	471,759	384,197	273,095	385,854	401,444
Contiguous U.S.	**1,897,782**	**1,627,766**	**1,409,694**	**1,414,546**	**1,553,646**
ASCC	291	322	319	355	259
Hawaii	4,124	7,932	10,907	8,743	10,996
Total Cost[1]	**1,902,197**	**1,636,020**	**1,420,920**	**1,423,644**	**1,564,901**

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

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding. •These data refer to electric utility costs and represent the total cash expenditures incurred during the year, in nominal dollars, that flows out to support demand-side management programs.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 44. U.S. Electric Utility Demand-Side Management Direct and Indirect Cost, 1999 and 2000
(Thousand Dollars)

Program	1999	2000
Total Direct Cost[1]	**1,250,689**	**1,384,232**
Energy Efficiency	820,108	938,666
Load Management	430,581	445,566
Indirect Utility Cost[2]	**172,955**	**180,669**
Cost (thousand dollars)	**1,423,644**	**1,564,901**

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

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

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours.

Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

U.S. Nonutility Power Producers

This chapter provides an overview of U.S. nonutility power producers, and their generating technologies, together with statistical data on capacity, generation, sales, consumption and emissions for 1996 through 2000. These data are aggregated at the U.S. Census division level. Since nonutility data for 1995 through 1997 are confidential, the EIA implemented information disclosure rules. (See "Nondisclosure of Data" in Appendix A.)

In 1989, the Energy Information Administration (EIA) began collecting nonutility electricity generation data on the Form EIA-867, "Annual Nonutility Power Producers Report" (renamed, Form EIA-860B, "Annual Electric Generator Report - Nonutility" starting with the 1998 collection). This survey enables the EIA to supplement its data on electric utility production and to fill the information gap on this growing source of electric power. The initial survey was developed to include capacity, fuel consumption, generation, and deliveries of electricity to traditional utilities. Due to the sensitivity of the data on costs and reliability expressed by representatives of the nonutility power producers, these data were excluded from the survey. (See "Form EIA-860B" in Appendix A.)

Background

Early in the 20th century, more than half of all electricity produced in the United States came from industrial firms. However, during the first half of the 20th century, major changes occurred in the industry: economies of scale in generation, decreased rates, and greatly improved reliability made electricity inexpensive and demand soared. Most industrial plants shifted away from generating their own power and opted to purchase electricity from their local utilities. By 1950, the electric utility industry was serving virtually all electricity demand, except for a few industries that generated small amounts for their own use. Electricity was inexpensive, capacity growth appeared to be limitless, and electric utilities were strictly regulated to protect the consumers.

By the late 1970's changing economic conditions and legislation made nonutility generation attractive again for many industrial facilities and power project developers. During the 1970's, the electric utility industry changed from one characterized by decreasing marginal costs to one of increasing costs. Inflation, the energy crises, environmental concerns, and the rising costs of nuclear power led to increased electricity rates and reduced growth in capacity. The oil-price shocks in the 1970's led to a dramatic rise in energy prices, while high interest rates and stricter Federal air quality regulations increased the cost of building power plants. These factors led to a re-examination of alternatives such as nonutility electric power.

Nonutility power producing facilities seeking to establish interconnected operations with electric utilities faced three major obstacles. First, utilities were seldom willing either to purchase the electric power output of nonutility producers or pay a fair rate for that output. Second, some utilities charged high rates for backup services to nonutility power producers. Third, facilities that provided electricity to a utility connected to the grid risked being considered a public utility and subject to extensive State and Federal regulation.

Congress acted to relieve a nationwide energy crisis by enacting the National Energy Act of 1978, which encompassed the Public Utility Regulatory Policies Act (PURPA) and four other laws: the National Energy Conservation Policy Act, the Powerplant and Industrial Fuel Use Act, the Natural Gas Policy Act, and the Energy Tax Act. PURPA provided for increased conservation of energy and increased efficiency in the use of facilities and resources by electric utilities. It called for State regulatory authorities to encourage conservation and energy efficiency and to provide for equitable rates. Some of the provisions of PURPA were designed to encourage the development of cogeneration and small power production by loosening the economic, regulatory, and institutional barriers that discouraged cogeneration and the use of renewable energy resources.

PURPA makes a distinction between facilities that qualify for benefits, referred to as qualifying facilities (QF's), and other generating facilities. QF's include cogenerators and small power producers. Cogeneration is an energy efficient technology, while small power production is defined in PURPA as a technology that primarily uses renewable energy sources. Other generating facilities include industrial and commercial generators and independent power producers without a designated franchised service area. The Federal Energy Regulatory Commission (FERC) is responsible for the implementation of PURPA and has established rules to encourage the development of cogenerators and small power production facilities. In addition, each State regulatory authority is required to implement such rules for each electric utility under its rate-making authority. The rules for the FERC program that define QF's are published in the *Code of Federal Regulations*, Title 18, Part 292.

Under FERC rules, cogeneration and small power production facilities may be designated as QF's if they meet specific ownership,[14] operating, and efficiency criteria. A facility may file an information report, known as a “self qualifying notice,” with the FERC if it meets the requirements of FERC published rules, or it may apply to the FERC for certification as a QF under PURPA. QF's are guaranteed that electric utilities will purchase their output at the utilities' avoided cost, which is the incremental cost that an electric utility would incur to produce or purchase an amount of power equivalent to that purchased from QF's. Additionally, QF's are guaranteed that electric utilities will provide back up service at prevailing (non discriminatory) rates.

PURPA became a catalyst for competition in the electricity supply industry because it opened generation markets to facilities that met certain ownership, operating, and efficiency criteria, established by the FERC. Utilities initially did not welcome this competition, but some utilities soon discovered that buying generation from a QF has certain advantages over adding to their own capacity, especially because of the increasing uncertainty of recovering capital costs.

Nonutilities are not subject to 'rate base' as the basis of the price setting process and, therefore, the economic regulation regarding recovery of the investments of nonutilities is generally established on a different basis from that of a regulated public utility that is subject to 'avoided cost' based pricing, pricing that is a direct result of negotiations between the parties, 'market-based' pricing and others. As a result of this exception, a shorter lead time exists for the types of contracts signed by the nonutilities with their contractors (turnkey and other incentive based construction contracts). This type of contract had not been the historical practice of the utility industry, but under current conditions, clearly utilities and nonutilities alike will avail themselves of whatever provisions will allow the shortest lead time and lowest cost. The utility and nonutility are both looking at the need for and timing of new capacity in very similar ways. The NERC Reliability Assessment 1996-2005 states that in the later years of the ten-year assessment period, a number of Regions and subregions are no longer reporting generation capacity additions needed to satisfy regional criteria, although they do recognize such needs. However, it does signal an increased reliance on short lead-time resources that allow commitments to be delayed until required and reflects a shift toward a market-driven supply where customers choose the quantity and level of supply appropriate for their purposes.

The growth of nonutilities was further advanced by the Energy Policy Act of 1992 (EPACT). EPACT expanded the nonutility markets by creating a new category of power producers called exempt wholesale generators (EWG), which are exempt from the corporate and geographic restrictions imposed by the Public Utility Holding Company Act of 1935 (PUHCA).[15] EWG's are defined as businesses that own and/or operate a facility exclusively for the generation of electric energy for sale at wholesale. Exempting EWG's from PUHCA regulation removed obstacles to wholesale power competition by allowing utilities and nonutilities to form EWG's without triggering the restrictions of PUHCA. EWG's differ from QF's in several ways. They are not required to meet PURPA's cogeneration or renewable fuels limitations, utilities are not required to purchase their power, and they may charge market-based rates.

While the passage of PURPA opened generation markets to nonutility power producers of electricity, EPACT expanded the wholesale generation markets by opening access to the transmission system. In 1996, the FERC issued rules for implementing open access to the transmission network. Marketing of EWG wholesale power is being facilitated by transmission provisions that gave FERC the authority to order utilities to provide access to their transmission systems at nondiscriminatory rates.

With increasing competition in the electric power industry, PURPA in under review for repeal or modification. Several bills were introduced in Congress in 1996 and 1997 that would either repeal or amend PURPA. Proponents of repeal or reform contend that its QF power purchase mandate is anticompetitive and costly, and its environmental and fuel diversification goals will be maintained by the workings of a free market. Opponents of PURPA's repeal maintain the mandate is a necessary check against utility monopoly power.

Nonutility Classifications

Cogeneration. The major technology used in nonutility generation is known as cogeneration. Cogeneration is the combined production of electric power and another form of useful energy (such as heat or steam) through the use of one energy source. The process can begin either with heat or steam production or with electricity generation. The unused energy from the first process is used as input to the second process. The primary energy source is generally a fossil fuel (coal, petroleum, or natural gas), although renewables are also used, particularly wood and waste. To receive QF status under PURPA from FERC, a cogenerating facility must meet the operating criteria by producing electric energy and “another form of useful thermal energy through the sequential use of energy.” In addition, depending on the technology of the cogeneration facility, it must meet specific efficiency criteria.

Cogeneration uses a number of technologies to produce electric power and another form of useful energy. The technology selected depends on the requirement for processed steam. Cogenerating tech-

14 FERC rules require that QF's be less than 50 percent owned by electric utilities.

15 PUCHA was designed to discourage holding companies from structuring their operations in ways that would prevent effective State regulation.

nologies are classified as "topping-cycle" and "bottoming-cycle" systems, depending on whether electrical or thermal energy is produced first. In a typical topping-cycle system (Figure 14), the energy input to the system is first transformed into electricity by using high-temperature, high-pressure steam from a boiler to drive a turbine to generate electricity. The waste heat, or the lower pressure steam exhausting from the turbine, is used as a source of processed heat. Topping-cycle systems are the most common and are used in commercial, rural, and industrial applications. The two configurations in Figure 10 represent most topping-cycle facilities.

In a bottoming-cycle system (Figure 11), high-temperature thermal energy is produced first for applications such as reheat furnaces, glass kilns, or aluminum metal furnaces. Heat is extracted from the hot exhaust stream and transferred (through one or more mediums) to drive a turbine. Bottoming-cycle systems are generally used by industrial processes that require very high temperature heat, thus making it economical to recover the waste heat.

Fossil-fueled steam turbine systems are used in most industrial cogenerating processes, while gas-turbine systems are used in most processes. Gas-turbine systems use combustion gases to drive a turbine to produce electricity and recover heat from the exhaust gases for waste-heat boilers. Compared with gas turbine systems, diesel engine systems are limited in application since they provide less useable processed heat per unit of electric power output. In a diesel system, the engine is cooled with water. The heated water is then used for processed steam, heat, or hot water applications. Exhaust gases can be used in a similar manner. Diesel systems are attractive to small cogenerating applications that need an instantaneous supply of electricity where the electric power requirement is generally greater than the heat requirement. With diesel systems, unlike some technologies, boiler warmup time is not necessary.

Small Power Production. To be designated as a small power producer under the 1978 PURPA regulations, a facility was limited to a capacity no greater than 80 megawatts and had to generate electricity using renewable energy as a primary source. In 1990, for specific energy sources (biomass (waste), solar, geothermal, and wind), the size restriction to qualify as a small power producer was removed. Fossil fuels can be used, but 75 percent or more of total energy consumption must be derived from renewable resources. The aggregate of fossil fuel usage cannot exceed 25 percent of total energy input during any calendar year. Reliance on these technologies can reduce the need to consume fossil fuels to generate electric power.

Renewable energy includes solar, wind, biomass, geothermal, and water (hydraulic). Solar thermal technology converts solar energy through high concentration and heat absorption into electricity or process energy and is mainly used in the Pacific Contiguous Census Division. Wind generators produce mechanical energy directly through shaft power. Windmills rotating parallel or perpendicular to the ground are the most common harnesses used in wind technology and are mainly concentrated in the Pacific Contiguous and West South Central Census Divisions. Biomass energy is derived from a variety of sources. The biomass resource base potentially includes hundreds of plant species, various agricultural and industrial residues and processing wastes, municipal solid waste and sewage, and animal wastes. Industrial wood and wood waste is the form of biomass energy most commonly used by nonutilities. When economic to do so, the industries that produce paper, wood, and agricultural products are increasing their use of biomass to improve efficiency of their operations and to contribute to their on-site energy requirements. These industries are indigenous to the South Atlantic and Pacific Contiguous Census Divisions. Geothermal technologies convert heat naturally present in the earth into energy and electricity by tapping into high- and low-temperature fluids and by extracting steam. Hydropower is derived by converting the potential energy of water to electrical energy using a hydraulic turbine connected to a generator. Hydropower and geothermal technologies are mainly concentrated in the Pacific Contiguous Census Division.

Other Nonutility Generators. In addition to facilities that are classified as qualifying cogenerators and small power producers, other nonutility companies produce electric power for their own use and for sale to electric utilities. They include independent power producers (IPP's), nonqualifying cogenerators, and other commercial and industrial establishments. These nonutility companies are built mainly to supply and sell power to electric utilities. They do not qualify under PURPA because of the ownership, operating, or efficiency criteria established by FERC. IPP's are defined by FERC as producers of electric power other than QF's that are unaffiliated with franchised utilities in the IPP's market area and that for other reasons lack significant market power. IPP's may lack market power due to restrictions imposed by their site or transmission access.

Nonutility Operations

Business Classification. The nonutility power producing industry operates in various sectors of the U.S. economy and is classified according to the *Standard Industrial Classification (SIC) Manual* of the Office of Management and Budget. In 1997, the SIC Manual name was changed to North American Industry Classification System (NAICS). The main classifications are:

Agriculture, Forestry, and Fishing
Mining
Construction
Manufacturing
Transportation and Public Utilities
Wholesale and Retail Trade
Finance, Insurance, and Real Estate
Services
Public Administration
Other.

A list of the categories of primary business activity within each classification is contained in Appendix A.

The nonutility power producing industry includes business entities that transform materials or substances into new products using mechanical or chemical processes. In some processes, the energy is transformed into steam for generating both electricity and another useful thermal output. This thermal output can be used directly in a manufacturing process such as paper production and indirectly for heating buildings or by other end users. The manufacturing sector uses the most energy (i.e. is the most energy intensive) because it creates new products using mechanical or chemical processes. It is therefore more cost-effective to produce one's own energy in this sector than in sectors that only require energy for space conditioning and lighting, such as the nonmanufacturing sectors.

Energy Sources. Most nonutility power producers use fossil fuels in their production processes. Many of them are able to switch from one fossil fuel to another when fuel supply is interrupted or when there is a price advantage in switching to another fuel. For example, they may switch from gas to oil in winter when their gas supplies are diverted to residential use, or from oil to coal when oil prices rise. Other nonutility power producers use various renewable energy sources. Increasingly, many facilities are able to switch from fossil fuels to renewable fuels. Many nonutility power producers use combustors that are able to burn two or more different fuels simultaneously, in varying combinations, to generate the desired heat output. Other nonutility power producers can only burn one fuel at a time, but their combustors can be converted to burn different fuels. Finally, many producers have multiple combustors that use different fuels to supply heat or power. Thus, the adaptability of nonutility power producers to using multiple fuel sources depends primarily on the type of generating equipment available and economic conditions. A nonutility power producer with many options for fuel choice has an economic advantage over a producer tied to only one fuel source.

Data Sources

Summary statistics on nonutility capacity, generation, sales, consumption, and emissions in the United States are provided in the following tables. Data for 1996 through 2000 are final. These data were obtained from the Form EIA-860B, "Annual Electric Generator Report - Nonutility" (prior Form EIA-867, "Annual Nonutility Power Producer Report.") The Form EIA-860B is 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. In 1992, the reporting threshold of the Form EIA-867 was lowered from 5 megawatts to 1 megawatt to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected from facilities with a nameplate capacity between 1 and 5 megawatts every 3 years. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure of the facility. Nonutilities generally install small, turn-key packaged generating facilities with minimal regulatory requirements which result in considerably less lead time to finance and build, as compared to traditional electric utility facilities.

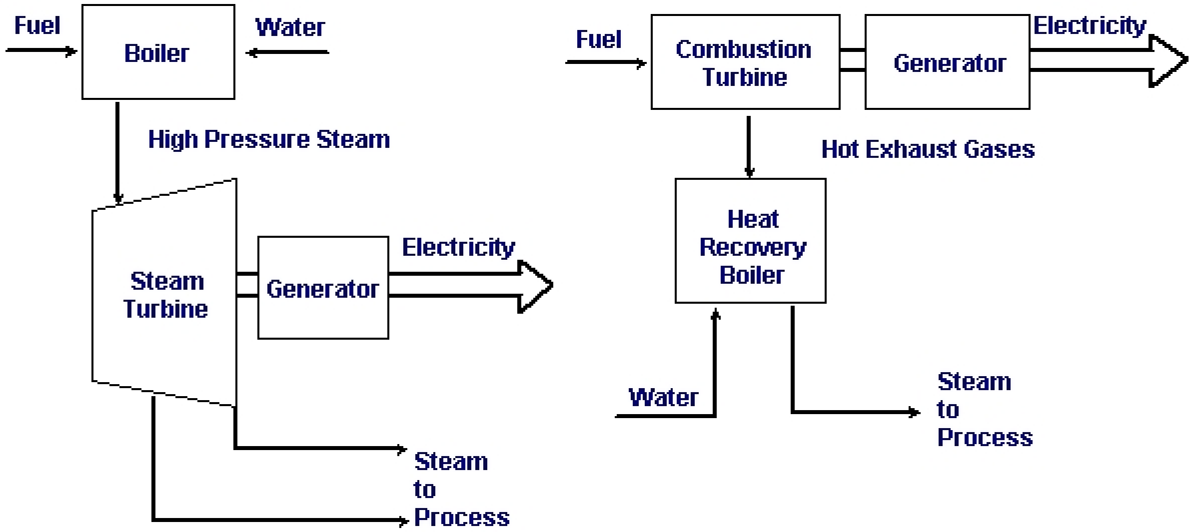
Some nonutility power producers of 1 or more megawatts use only fossil fuels; some use only renewable energy; and some use a combination of both fossil fuels and renewable energy sources. Although the majority of nonutility power producers generate electric power using fossil energy, those using renewable energy represent a large portion of capacity. Because of the consumption of multiple energy sources by some generating units, capacity and generation were allocated by energy source. The algorithms used to allocate installed capacity and generation by energy source are discussed in the Technical Notes (Appendix A).

The other energy sources in Tables 45, 47, 48, 51, and 52 include hydrogen, sulfur, batteries, chemicals, and purchased steam.

The number of facilities shown for 2000 includes operational facilities in 1999 and new facilities or planned facilities that became operational during that year.

The total capacity for 1998 through 2000 (Table 45) includes all operable generating units including units not normally used but on standby with little or no generation, and units out of service for the entire reporting year that are expected to be returned to service in the future. Units on standby, test, maintenance/repairs, out of service, and indefinite shutdown represented 43 percent of the total nonutility generating capacity in 2000.

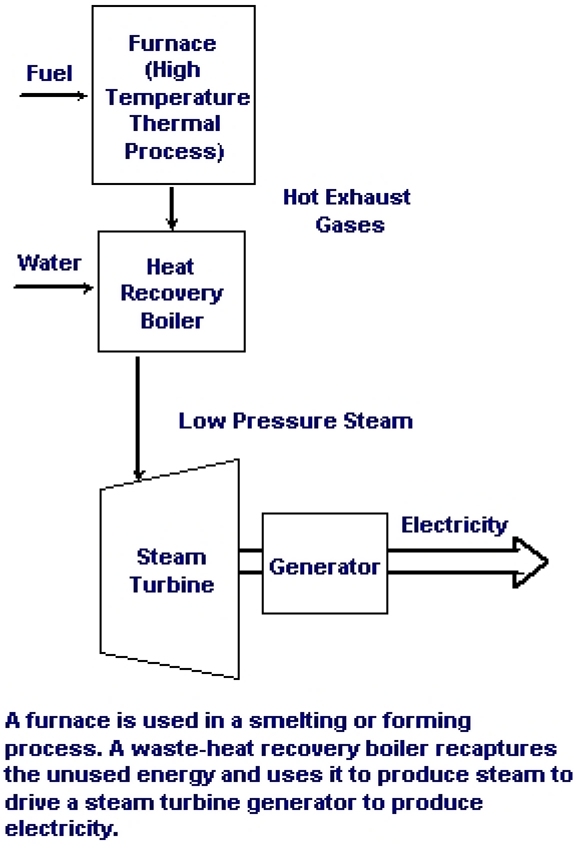
Figure 10. Two Topping-Cycle Plant Configurations



1. A boiler produces steam to power a turbine-generator to produce electricity. The turbine steam leaving the turbine is used in thermal applications such as space heating or food preparation.
2. A combustion turbine or diesel engine burns fuel to spin a shaft connected to a generator to produce electricity. Waste heat from the burning fuel is recaptured in a waste-heat recovery boiler and is used for direct heating or is used to produce steam for thermal applications.

Source: Federal Energy Regulatory Commission, *Cogeneration,* 1985.

Figure 11. Bottoming-Cycle Plant Configuration



Source: Federal Energy Regulatory Commission, *Cogeneration,* 1985.

Table 45. Summary Statistics for U.S. Nonutility Generating Facilities, 1998 Through 2000

Item	1998 R	1999 R	2000
Installed Capacity (megawatts)[1]	**98,213**	**160,525**	**228,594**
Coal[2]	17,217	40,580	59,196
Petroleum Only	2,472	4,161	11,015
Natural Gas[5]	39,795	47,516	73,186
Other Gas[3]	1,560	1,813	1,723
Dual Fired[4]	18,171	41,190	47,534
Hydroelectric Pumped Storage	—	600	1,453
Hydroelectric (conventional)	4,340	5,403	5,761
Geothermal	1,424	2,719	2,683
Solar	864	963	410
Wind	1,711	2,222	2,323
Biomass[6]	10,545	10,510	10,144
Nuclear	—	2,527	12,622
Other[7]	114	322	545
Gross Generation (million kilowatthours)	**422,985**	**544,561**	**828,325**
Coal[2]	70,014	121,072	287,141
Petroleum[4]	19,519	33,087	41,249
Natural Gas[5]	227,719	268,237	323,143
Other Gas[3]	13,893	14,632	14,620
Hydroelectric Pumped Storage	—	—	1,655
Hydroelectric (conventional)	14,713	20,147	22,644
Geothermal	9,932	13,638	14,461
Solar	529	518	526
Wind	3,053	4,510	5,621
Biomass[6]	59,894	61,211	62,288
Nuclear	—	3,318	49,959
Other[7]	3,718	4,191	5,017
Consumption[8]			
Coal (thousand short tons)	56,850	76,063	156,066
Petroleum (thousand barrels)[9]	78,858	85,016	93,474
Natural Gas (million cubic feet)	2,666,430	3,191,523	3,633,650
Other Gas (million cubic feet)[3]	873,107	1,473,207	1,666,166
Supply and Disposition (million kilowatthours)			
Gross Generation	422,985	544,561	828,325
Receipts[10]	90,675	90,395	95,158
Sales to Utilities[11]	249,496	342,138	607,130
Sales to Other End Users[12]	25,777	41,422	53,059
Facility Use	236,775	251,413	263,302

1 There is a discontinuity in capacity estimates between 1999 and earlier years due to a change in reporting practices. In 1999 for the first time respondents self identified the facility's primary energy source resulting in a reclassification compared to earlier years in some cases.
2 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, liqnite waste, tar coal, and waste coal.
3 Includes butane, propane, and other gas.
4 Includes petroleum, petroleum coke, diesel, kerosene, light oil, liquid butane, liquid propane, oil waste, sludge oil, and tar oil.
5 Includes natural gas and waste heat.
6 Includes black liquor, peat, railroad ties, red liquor, sludge wood, spent sulfite liquor, utility poles, and wood/wood waste, agricultural byproducts, digester gas, fish oil, liquid acetonitrile waste, landfill gas, medical waste, methane, municipal solid waste, paper pellets, sludge waste, solid byproducts, straw, tires, tall oil, and waste alcohol.
7 Includes batteries, chemicals, hydrogen, pitch, purchased steam, and sulfur.
8 Includes all combustible fuels burned at generating facilities (not just for the production of electricity).
9 Includes petroleum coke consumption of 4,427 thousand short tons for 1998, 2,915 thousand short tons for 1999, and 3,537 thousand short tons for 2000.
10 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
11 Includes sales, interchanges, and exchanges of electric energy with utilities.
12 Includes sales, interchanges, and exchanges of electric energy with other nonutilities. The disparity in this data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-860B (prior, Form EIA-867) is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures attribute to the disparity.

R = Revised data.

Notes: • The installed capacity is determined by the primary energy source even if multiple energy sources are indicated by the respondent. •All data are for 1 megawatt and greater. •Data are final. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. •See the Technical Notes for the methodology for allocating capacity and generation by energy sources, respectively.

Sources: Energy Information Administration, Form EIA-860B, ''Annual Electric Generator Report - Nonutility''.

Table 46. Installed Capacity at U.S. Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Source, and Census Division, 1998 Through 2000

(Megawatts)

Census Division	Fossil Fuels[1]	Renewables/ Other/ Nuclear[2]	Both Fossil Fuels and Renewables/ Other/ Nuclear
		1998[R]	
New England	8,304	3,102	434
Middle Atlantic	10,726	854	1,226
East North Central	6,659	822	910
West North Central	1,199	250	237
South Atlantic	8,631	4,120	899
East South Central	2,705	238	1,430
West South Central	12,869	993	1,943
Mountain	2,032	563	291
Pacific	20,981	5,244	489
U.S. Total	**74,347**	**17,705**	**6,160**
		1999[R]	
New England	14,882	4,319	307
Middle Atlantic	31,355	3,027	718
East North Central	20,491	1,762	3,423
West North Central	1,227	719	126
South Atlantic	9,224	4,285	907
East South Central	4,422	1,216	433
West South Central	14,028	1,769	2,073
Mountain	5,252	1,287	5
Pacific	26,077	6,790	399
U.S. Total	**126,960**	**25,173**	**8,392**
		2000	
New England	17,869	5,330	196
Middle Atlantic	51,556	11,531	952
East North Central	29,323	1,871	600
West North Central	1,252	736	118
South Atlantic	22,881	5,831	1,171
East South Central	5,746	1,011	710
West South Central	22,214	1,321	4,327
Mountain	5,521	1,387	210
Pacific	25,758	6,882	2,289
U.S. Total	**182,121**	**35,900**	**10,573**

1 Includes petroleum, natural gas, coke breeze, fine coal and/or coal as energy sources.

2 Includes hydroelectric, geothermal, solar, wind, wood/wood waste, agriculture byproducts, black liquor, digester gas, fish oil, landfill gas, liquid acetonitrile waste, medical waste, methane, municipal solid waste, paper pellets, peat, purchased gas, railroad ties, red liquor, sludge waste, solid byproducts, sludge wood, straw, tires, tall oil, utility poles, waste alcohol, other (batteries, chemicals, hydrogen, peat, purchased steam and sulfur), and/or nuclear as energy sources.

R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data are final. •See Technical Notes for a description of allocating capacity. •Total may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table 47. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1998 Through 2000

(Megawatts)

Census Division	Coal[1]	Natural Gas/ Other Gas[2]	Petroleum[3] only / and Dual Fired[4]	Hydroelectric/ Geothermal/ Solar / Wind	Wood[5] /Waste [6]	Other[7] /Nuclear	Total
				1998[R]			
New England	2,257	1,271	5,085	1,666	1,559	3	11,841
Middle Atlantic	2,561	4,334	4,472	477	958	22	12,824
East North Central	3,661	3,142	765	104	711	8	8,390
West North Central	794	110	423	202	187	—	1,715
South Atlantic	3,656	2,436	3,187	1,019	3,353	—	13,650
East South Central	2,463	492	146	212	1,063	—	4,376
West South Central	829	12,021	1,569	251	1,053	82	15,805
Mountain	255	1,491	421	581	150	—	2,899
Pacific	740	16,058	4,576	3,828	1,512	—	26,713
U.S. Total	**17,217**	**41,355**	**20,643**	**8,339**	**10,545**	**114**	**98,213**
				1999[R]			
New England	2,883	1,048	11,258	2,070	1,576	673	19,508
Middle Atlantic	13,070	3,959	15,045	1,170	963	894	35,101
East North Central	13,410	9,214	1,291	101	669	992	25,676
West North Central	818	105	430	532	188	—	2,073
South Atlantic	3,835	1,068	5,223	1,052	3,239	—	14,417
East South Central	2,397	2,226	145	212	1,091	—	6,070
West South Central	829	13,619	1,652	390	1,089	290	17,870
Mountain	2,593	2,110	554	1,135	152	—	6,543
Pacific	745	15,979	9,752	5,245	1,545	—	33,267
U.S. Total	**40,580**	**49,328**	**45,351**	**11,907**	**10,510**	**2,849**	**160,525**
				2000			
New England	2,256	4,218	11,591	3,092	1,568	670	23,395
Middle Atlantic	22,171	7,076	23,260	1,338	1,037	9,156	64,039
East North Central	14,268	9,992	5,663	101	785	985	31,795
West North Central	831	209	330	536	200	—	2,106
South Atlantic	9,539	3,422	11,091	649	2,926	2,256	29,883
East South Central	2,556	3,786	114	172	800	40	7,467
West South Central	2,732	21,690	2,078	368	965	29	27,862
Mountain	2,614	2,454	664	1,192	168	27	7,118
Pacific	2,229	22,061	3,758	5,182	1,696	4	34,929
U.S. Total	**59,196**	**74,908**	**58,550**	**12,629**	**10,144**	**13,167**	**228,594**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, lignite waste, tar coal, and waste coal.
2 Includes natural gas, waste heat, butane, other gas, and propane.
3 Includes petroleum, petroleum coke, diesel, light oil, kerosene, liquid butane, oil waste, sludge oil, liquid propane, and tar oil.
4 Includes petroleum and natural gas used as a fuel combination.
5 Includes black liquor, peat, railroad ties, red liquor, sludge wood, spent sulfite liquor, utility poles, and wood/wood waste.
6 Includes agricultural byproducts, digester gas, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solids, tall oil.
7 Includes batteries, chemicals, hydrogen, peat, sulfur, purchased steam, and other.
R = Revised data.

Notes: • The installed capacity is determined by the primary energy source even if multiple energy sources are indicated by the respondent. •All data are for 1 megawatt and greater. •Data are final. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-860B ‘‘Annual Electric Generator Report - Nonutility’’.

Table 48. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and State, 2000

(Megawatts)

State	Coal[1]	Natural Gas/ Other Gas[2]	Petroleum[3] only / and Dual Fired[4]	Hydroelectric/ Geothermal/ Solar / Wind	Wood[5] /Waste [6]	Other[7] /Nuclear	Total
Alabama	117	658	5	—	493	—	1,273
Alaska	90	158	104	—	—	—	352
Arizona	71	70	47	—	—	—	187
Arkansas	—	9	40	1	368	—	418
California	436	20,740	3,084	4,882	1,099	4	30,244
Colorado	35	1,190	35	32	20	—	1,312
Connecticut	588	840	2,725	140	262	—	4,556
Delaware	282	420	875	—	—	—	1,577
District of Columbia	—	—	868	—	—	—	868
Florida	740	856	1,490	—	1,213	387	4,686
Georgia	279	700	1,769	12	520	—	3,280
Hawaii	228	9	385	68	155	—	844
Idaho	19	27	—	264	133	16	460
Illinois	11,597	3,438	4,393	21	138	985	20,573
Indiana	708	2,757	282	—	33	—	3,780
Iowa	319	—	83	198	10	—	611
Kansas	—	48	4	3	—	—	54
Kentucky	2,048	27	99	—	4	—	2,178
Louisiana	1,903	4,501	637	192	322	22	7,577
Maine	102	1,189	1,808	720	733	—	4,552
Maryland	5,109	698	2,766	19	138	1,829	10,558
Massachusetts	1,566	1,377	6,465	1,659	378	670	12,114
Michigan	353	2,513	36	28	499	—	3,430
Minnesota	382	147	231	335	176	—	1,272
Mississippi	—	1,965	6	—	279	—	2,250
Missouri	100	6	7	—	—	—	113
Montana	2,351	—	65	588	11	—	3,014
Nebraska	8	2	5	—	4	—	18
Nevada	—	1,014	210	214	—	—	1,438
New Hampshire	—	5	40	382	154	—	582
New Jersey	1,823	2,057	8,823	13	215	4,151	17,082
New Mexico	—	90	301	—	2	—	393
New York	3,515	4,322	10,518	1,050	410	1,780	21,595
North Carolina	990	20	1,079	375	202	40	2,706
North Dakota	21	8	—	—	10	—	39
Ohio	1,142	1,139	154	—	20	—	2,456
Oklahoma	464	282	10	—	80	—	835
Oregon	14	719	6	126	190	—	1,054
Pennsylvania	16,834	697	3,919	275	412	3,226	25,362
Rhode Island	—	807	553	3	15	—	1,378
South Carolina	109	118	597	27	247	—	1,098
South Dakota	–-	–-	–-	–-	–-	–-	–-
Tennessee	391	1,136	5	172	24	40	1,766
Texas	365	16,898	1,393	175	195	7	19,031
Utah	108	4	2	4	2	—	120
Vermont	—	—	—	187	26	—	213
Virginia	1,702	488	1,648	21	606	—	4,465
Washington	1,462	435	179	105	252	—	2,434
West Virginia	328	123	—	196	—	—	646
Wisconsin	467	144	798	52	96	—	1,556
Wyoming	30	59	4	90	—	12	194
U.S. Total	**59,196**	**74,908**	**58,550**	**12,629**	**10,144**	**13,167**	**228,594**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, lignite waste, tar coal, and waste coal.
2 Includes natural gas, waste heat, butane, other gas, and propane.
3 Includes petroleum, petroleum coke, diesel, light oil, kerosene, liquid butane, oil waste, sludge oil, liquid propane, and tar oil.
4 Includes petroleum and natural gas used as a fuel combination.
5 Includes black liquor, peat, railroad ties, red liquor, sludge wood, spent sulfite liquor, utility poles, and wood/wood waste.
6 Includes agricultural byproducts, digester gas, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solids, tall oil.
7 Includes batteries, chemicals, hydrogen, peat, sulfur, purchased steam, and other.
R = Revised data.

Notes: • The installed capacity is determined by the primary energy source even if multiple energy sources are indicated by the respondent. •All data are for 1 megawatt and greater. •Data are final. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860B ‘‘Annual Electric Generator Report - Nonutility’’.

Table 49. Installed Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1998 Through 2000

(Megawatts)

Census Division	QF Capacity		Non-QF Capacity		Total Capacity	
	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)
			1998R			
New England	18	2,945	206	8,896	224	11,841
Middle Atlantic	51	7,531	245	5,293	296	12,824
East North Central	11	780	227	7,610	238	8,390
West North Central	1	287	85	1,428	86	1,715
South Atlantic	14	3,118	261	10,533	275	13,650
East South Central	1	12	64	4,364	65	4,376
West South Central	35	8,883	141	6,922	176	15,805
Mountain	14	1,126	112	1,773	126	2,899
Pacific	49	4,605	477	22,108	526	26,713
U.S. Total	**194**	**29,287**	**1,818**	**68,926**	**2,012**	**98,213**
			1999R			
New England	18	3,125	263	16,383	281	19,508
Middle Atlantic	51	7,522	347	27,579	398	35,101
East North Central	9	739	249	24,937	258	25,676
West North Central	1	287	90	1,786	91	2,073
South Atlantic	14	3,118	261	11,299	275	14,417
East South Central	1	12	67	6,058	68	6,070
West South Central	41	10,381	142	7,489	183	17,870
Mountain	16	1,809	126	4,735	142	6,543
Pacific	48	5,818	480	27,449	528	33,267
U.S. Total	**199**	**32,811**	**2,025**	**127,714**	**2,224**	**160,525**
			2000			
New England	21	4,631	280	18,764	301	23,395
Middle Atlantic	51	10,840	396	53,199	447	64,039
East North Central	10	789	279	31,006	289	31,795
West North Central	3	316	92	1,790	95	2,106
South Atlantic	15	3,446	286	26,438	301	29,883
East South Central	4	1,134	67	6,334	71	7,467
West South Central	48	17,478	149	10,383	197	27,862
Mountain	15	1,792	135	5,326	150	7,118
Pacific	47	5,387	480	29,542	527	34,929
U.S. Total	**214**	**45,813**	**2,164**	**182,781**	**2,378**	**228,594**

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (qualifying cogen, qualifying small power producers, and exempt wholesale generators).

Non-QF = Cogenerators and other nonutility generators that have not obtained qualifying status.

Notes: • The installed capacity is determined by the primary energy source even if multiple energy sources are indicated by the respondent. •All data are for 1 megawatt and greater. •Data are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table 50. Installed Capacity at U.S. Nonutility Generating Facilities Attributed to Major Industry Group and Census Division, 1998 through 2000

(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1998[R]			
New England	2,635	5,072	142	—	—	3,992	11,841
Middle Atlantic	9,411	2,200	569	205	222	218	12,824
East North Central	5,033	2,604	677	—	58	18	8,390
West North Central	1,109	217	172	203	—	15	1,715
South Atlantic	9,329	3,604	169	6	63	480	13,650
East South Central	2,149	2,176	14	26	11	—	4,376
West South Central	14,567	959	197	68	—	14	15,805
Mountain	943	952	134	241	9	620	2,899
Pacific	6,047	6,573	431	2,526	494	10,643	26,713
U.S. Total	**51,223**	**24,356**	**2,504**	**3,275**	**856**	**15,999**	**98,213**
				1999[R]			
New England	2,746	7,754	143	—	—	8,865	19,508
Middle Atlantic	9,389	20,079	562	207	220	4,644	35,101
East North Central	5,392	18,313	669	—	6	1,296	25,676
West North Central	1,136	524	172	203	—	38	2,073
South Atlantic	8,958	4,123	172	6	63	1,095	14,417
East South Central	2,176	2,213	14	26	11	1,630	6,070
West South Central	15,642	1,939	197	67	—	25	17,870
Mountain	946	4,084	164	243	—	1,106	6,543
Pacific	6,124	13,181	424	2,520	206	10,812	33,267
U.S. Total	**52,508**	**72,210**	**2,517**	**3,273**	**505**	**29,511**	**160,525**
				2000			
New England	3,018	10,327	140	—	—	9,910	23,395
Middle Atlantic	9,257	49,081	564	205	220	4,711	64,039
East North Central	5,407	22,677	691	—	6	3,014	31,795
West North Central	1,149	545	171	203	—	38	2,106
South Atlantic	8,989	17,882	170	6	63	2,772	29,883
East South Central	2,195	3,179	14	26	11	2,043	7,467
West South Central	16,841	10,577	197	67	—	180	27,862
Mountain	924	4,809	163	224	—	998	7,118
Pacific	6,138	14,797	419	2,567	240	10,768	34,929
U.S. Total	**53,918**	**133,874**	**2,530**	**3,299**	**539**	**34,435**	**228,594**

R = Revised data.

Notes: • The installed capacity is determined by the primary energy source even if multiple energy sources are indicated by the respondent. •All data are for 1 megawatt and greater. •Data are final. •See Technical Notes for North American Industry Classification System for these industry groups. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table 51. Gross Generation for U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1998 Through 2000
(Million Kilowatthours)

Census Division	Coal[1]	Petroleum[2]	Natural Gas/ Other Gas[3]	Hydro- Electric	Geothermal/ Solar/Wind	Wood[4] / Waste[5]	Other[6] / Nuclear	Total
				1998[R]				
New England	5,427	6,425	16,936	3,311	—	9,177	—	41,277
Middle Atlantic	14,588	1,080	41,929	1,970	—	7,059	62	66,688
East North Central	9,749	801	17,723	436	—	5,215	41	33,964
West North Central	3,569	57	1,330	294	148	901	—	6,299
South Atlantic	17,315	2,857	13,534	2,619	—	16,080	2,425	54,830
East South Central	7,099	580	2,965	807	—	6,625	105	18,181
West South Central	6,368	3,335	77,621	1,083	81	6,370	894	95,751
Mountain	1,642	457	8,090	1,180	1,589	611	175	13,744
Pacific	4,257	3,927	61,484	3,013	11,696	7,858	16	92,252
U.S. Total	**70,014**	**19,519**	**241,612**	**14,713**	**13,514**	**59,894**	**3,718**	**422,985**
				1999[R]				
New England	12,941	18,846	19,558	5,963	—	9,289	2,668	69,265
Middle Atlantic	42,437	2,389	48,616	3,918	—	7,420	331	105,111
East North Central	16,971	711	19,883	436	—	5,215	448	43,664
West North Central	3,619	65	1,254	352	819	965	—	7,073
South Atlantic	17,723	3,066	13,677	1,986	—	16,406	2,418	55,277
East South Central	14,100	216	3,595	658	—	6,888	122	25,579
West South Central	6,392	3,331	83,515	815	323	6,151	1,335	101,861
Mountain	2,439	534	8,112	3,467	1,472	612	163	16,799
Pacific	4,449	3,930	84,660	2,552	16,052	8,265	24	119,932
U.S. Total	**121,072**	**33,087**	**282,869**	**20,147**	**18,666**	**61,211**	**7,509**	**544,561**
				2000				
New England	14,856	19,272	24,359	8,360	—	9,668	5,837	82,353
Middle Atlantic	112,125	6,708	51,603	5,798	20	7,408	29,461	213,123
East North Central	65,615	1,144	21,854	429	—	5,638	7,128	101,809
West North Central	3,842	64	1,119	327	1,226	1,068	—	7,647
South Atlantic	30,991	5,081	16,067	1,942	—	15,940	10,116	80,136
East South Central	14,548	197	4,473	525	—	6,966	114	26,822
West South Central	15,460	3,305	99,690	541	497	6,186	2,107	127,787
Mountain	18,486	646	11,424	4,379	1,698	608	190	37,432
Pacific	11,218	4,832	107,175	1,997	17,166	8,807	23	151,217
U.S. Total	**287,141**	**41,249**	**337,763**	**24,299**	**20,608**	**62,288**	**54,976**	**828,325**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, lignite waste, tar coal, and waste coal.
2 Includes petroleum, petroleum coke, diesel, kerosene, light oil, liquid butane, liquid propane, oil waste, sludge oil, and tar oil.
3 Includes natural gas, waste heat, butane, other gas, and propane.
4 Includes black liquor, peat, railroad ties, red liquor, sludge wood, spent sulfite liquor, utility poles, and wood/wood waste.
5 Includes agricultural byproducts, digester gas, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solids, tall oil.
6 Includes batteries, chemicals, hydrogen, peat, sulfur, purchased steam, and other.
R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data are final. •Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-860B ‘‘Annual Electric Generator Report - Nonutility’’.

Table 52. Gross Generation for U.S. Nonutility Generating Facilities by Energy Source and State, 2000
(Million Kilowatthours)

State	Coal[1]	Petroleum[2]	Natural Gas/ Other Gas[3]	Hydro-Electric	Geothermal/ Solar/Wind	Wood[4] / Waste[5]	Other[6] / Nuclear	Total
Alaska	378	85	798	—	—	—	—	1,261
Alabama	625	134	1,668	—	—	4,344	1	6,771
Arkansas	101	16	724	—	—	1,704	8	2,553
Arizona	355	1	489	—	—	5	—	849
California	2,517	2,834	97,068	1,305	16,806	6,373	23	126,925
Colorado	300	18	3,778	126	—	20	—	4,242
Connecticut	3,372	7,123	4,256	383	—	1,784	—	16,918
District of Columbia	—	50	—	—	—	—	—	50
Delaware	821	474	625	—	—	19	—	1,940
Florida	5,926	1,469	7,525	—	—	6,056	2,138	23,114
Georgia	1,166	1,039	2,595	26	—	3,306	2	8,134
Hawaii	1,693	1,622	43	89	293	571	—	4,310
Iowa	1,287	6	118	13	495	75	—	1,993
Idaho	74	4	319	864	—	518	89	1,868
Illinois	55,387	517	5,020	84	—	833	7,128	68,969
Indiana	4,032	131	4,196	—	—	134	—	8,494
Kansas	—	1	36	15	—	—	—	52
Kentucky	12,273	28	158	—	—	13	—	12,471
Louisiana	9,377	1,557	21,951	538	—	2,965	470	36,858
Massachusetts	10,791	9,054	10,771	2,428	—	2,348	5,683	41,076
Maryland	9,480	911	1,098	19	—	877	7,735	20,120
Maine	693	2,981	3,199	3,624	—	4,073	154	14,724
Michigan	1,375	209	10,527	101	—	3,059	—	15,271
Minnesota	2,102	37	879	299	732	957	—	5,005
Missouri	298	5	18	—	—	10	—	332
Mississippi	—	11	2,099	—	—	1,775	—	3,885
Montana	17,045	558	50	3,367	—	48	—	21,068
North Carolina	4,517	380	301	976	—	1,896	241	8,311
North Dakota	120	14	54	—	—	8	—	197
Nebraska	35	1	14	—	—	17	—	67
New Hampshire	—	63	65	1,111	—	1,162	—	2,401
New Jersey	5,051	826	16,290	14	—	1,450	10,729	34,361
New Mexico	—	60	1,125	—	—	9	—	1,194
Nevada	—	—	4,950	14	1,449	—	22	6,436
New York	22,253	3,644	32,102	5,114	10	3,054	1,670	67,847
Ohio	3,497	13	721	—	—	673	—	4,903
Oklahoma	3,012	7	1,248	—	—	158	—	4,424
Oregon	18	17	4,807	337	67	673	—	5,920
Pennsylvania	84,820	2,238	3,211	670	10	2,904	17,062	110,915
Rhode Island	—	51	6,044	5	—	118	—	6,218
South Carolina	574	189	770	37	—	1,504	—	3,074
South Dakota	--	--	--	--	--	--	--	--
Tennessee	1,650	24	549	525	—	835	113	3,695
Texas	2,971	1,725	75,767	4	497	1,359	1,629	83,952
Utah	478	1	340	8	—	9	—	837
Virginia	6,208	559	2,947	63	—	2,283	—	12,059
Vermont	—	—	24	809	—	183	—	1,016
Washington	6,612	274	4,459	266	—	1,190	—	12,800
Wisconsin	1,325	274	1,390	244	—	939	—	4,172
West Virginia	2,299	9	206	821	—	—	—	3,336
Wyoming	235	3	372	—	248	—	79	938
U.S. Total	**287,141**	**41,249**	**337,763**	**24,299**	**20,608**	**62,288**	**54,976**	**828,325**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, lignite waste, tar coal, and waste coal.
2 Includes petroleum, petroleum coke, diesel, kerosene, light oil, liquid butane, liquid propane, oil waste, sludge oil, and tar oil.
3 Includes natural gas, waste heat, butane, other gas, and propane.
4 Includes black liquor, peat, railroad ties, red liquor, sludge wood, spent sulfite liquor, utility poles, and wood/wood waste.
5 Includes agricultural byproducts, digester gas, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solids, tall oil.
6 Includes batteries, chemicals, hydrogen, peat, sulfur, purchased steam, and other.
R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table 53. Gross Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1998 Through 2000

(Million Kilowatthours)

Census Division	QF Generation		Non-QF Generation		Total Generation	
	No. of Facilities[1]	Generation (million kilowatthours)	No. of Facilities[1]	Generation (million kilowatthours)	No. of Facilities[1]	Generation (million kilowatthours)
			1998[R]			
New England	116	21,761	99	19,515	215	41,277
Middle Atlantic	245	64,240	42	2,448	287	66,688
East North Central	112	22,185	110	11,778	222	33,964
West North Central	26	3,239	58	3,060	84	6,299
South Atlantic	157	43,508	105	11,322	262	54,830
East South Central	27	7,550	37	10,631	64	18,181
West South Central	114	86,562	61	9,189	175	95,751
Mountain	84	11,291	36	2,453	120	13,744
Pacific	380	69,050	130	23,201	510	92,252
U.S. Total	**1,261**	**329,387**	**678**	**93,598**	**1,939**	**422,985**
			1999[R]			
New England	117	21,689	152	47,576	269	69,265
Middle Atlantic	230	61,440	156	43,671	386	105,111
East North Central	113	22,566	132	21,098	245	43,664
West North Central	26	3,396	63	3,677	89	7,073
South Atlantic	154	44,581	108	10,697	262	55,277
East South Central	26	7,715	40	17,864	66	25,579
West South Central	116	92,256	64	9,605	180	101,861
Mountain	80	11,179	56	5,620	136	16,799
Pacific	368	68,789	150	51,143	518	119,932
U.S. Total	**1,230**	**333,610**	**921**	**210,951**	**2,151**	**544,561**
			2000			
New England	123	22,502	169	59,851	292	82,353
Middle Atlantic	226	61,240	214	151,884	440	213,123
East North Central	128	22,208	145	79,601	273	101,809
West North Central	26	3,435	65	4,212	91	7,647
South Atlantic	157	57,420	130	22,716	287	80,136
East South Central	26	7,237	44	19,585	70	26,822
West South Central	116	97,911	77	29,876	193	127,787
Mountain	85	11,610	61	25,822	146	37,432
Pacific	366	70,554	153	80,663	519	151,217
U.S. Total	**1,253**	**354,116**	**1,058**	**474,210**	**2,311**	**828,325**

1 The number of facilities with no generation that were not retired were 80 in 1998, 65 in 1999, 13 in 2000.

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (qualifying cogen, qualifying small power producers, and exempt wholesale generators).

Non-QF = Cogenerators and other nonutility generators that have not obtained qualifying status.

R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data are final. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table 54. Gross Generation at U.S. Nonutility Generating Facilities Attributed to Major Industry Group and Census Division, 1998 Through 2000

(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1998R			
New England	15,327	19,959	432	—	—	5,559	41,277
Middle Atlantic	46,197	13,024	3,584	1,517	890	1,476	66,688
East North Central	25,000	6,498	2,366	—	56	44	33,964
West North Central	4,045	660	427	1,146	—	21	6,299
South Atlantic	42,161	10,482	756	2	31	1,398	54,830
East South Central	12,753	5,155	92	124	56	—	18,181
West South Central	88,975	5,718	585	396	—	77	95,751
Mountain	5,589	4,287	868	492	57	2,451	13,744
Pacific	34,035	23,401	2,657	18,030	1,562	12,567	92,252
U.S. Total	**274,083**	**89,185**	**11,766**	**21,707**	**2,650**	**23,593**	**422,985**
				1999R			
New England	15,178	26,709	528	—	—	26,850	69,265
Middle Atlantic	45,792	49,166	3,131	1,483	1,333	4,206	105,111
East North Central	25,758	15,065	2,315	—	17	509	43,664
West North Central	4,237	1,286	472	1,024	—	54	7,073
South Atlantic	40,285	12,250	745	2	25	1,970	55,277
East South Central	12,975	11,882	96	117	53	455	25,579
West South Central	94,296	6,546	572	362	—	85	101,861
Mountain	5,603	7,680	870	539	—	2,108	16,799
Pacific	34,994	39,343	2,645	17,231	1,424	24,296	119,932
U.S. Total	**279,116**	**169,928**	**11,374**	**20,758**	**2,852**	**60,534**	**544,561**
				2000			
New England	15,617	28,341	535	—	—	37,860	82,353
Middle Atlantic	46,604	148,427	2,836	1,461	1,138	12,658	213,123
East North Central	24,569	67,707	2,156	—	17	7,361	101,809
West North Central	4,168	1,725	526	1,148	—	79	7,647
South Atlantic	42,345	33,220	781	2	30	3,757	80,136
East South Central	12,483	13,602	74	115	57	491	26,822
West South Central	100,627	26,060	562	356	—	182	127,787
Mountain	5,758	26,155	861	664	—	3,994	37,432
Pacific	37,644	50,396	2,609	17,482	1,541	41,545	151,217
U.S. Total	**289,814**	**395,633**	**10,939**	**21,228**	**2,783**	**107,928**	**828,325**

R = Revised Data.

Notes: •All data are for 1 megawatt and greater. •Data are final. •See Technical Notes for North American Industry Classification System for these industry groups. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860B ‘‘Annual Electric Generator Report - Nonutility’’.

Table 55. Consumption of Fossil Fuels at U.S. Nonutility Generating Facilities by State, 2000

State	Coal (thousand short tons)				Petroleum (thousand barrels)				Gas (thousand Mcf)	
	Anthracite[1]	Bituminous[2]	Lignite	Total	Heavy Oil	Light Oil	Total	Petroleum Coke (thousand short tons)	Natural Gas	Other Gas
Alaska	—	589	—	589	—	197	197	—	10,745	—
Alabama	—	834	117	951	386	454	839	—	49,609	72,529
Arkansas	—	178	—	178	104	8	112	—	28,712	2,188
Arizona	—	350	—	350	—	3	3	—	4,421	103
California	3	1,768	—	1,771	1,005	646	1,651	1,001	966,658	96,702
Colorado	—	339	—	339	2	173	175	—	37,581	681
Connecticut	—	1,473	—	1,473	11,474	155	11,628	—	41,586	3,516
District of Columbia	—	—	—	—	—	106	106	—	—	—
Delaware	—	352	—	352	1,310	69	1,379	73	4,035	7,223
Florida	—	2,730	—	2,730	3,535	110	3,645	—	75,352	48,818
Georgia	—	1,494	—	1,494	2,322	584	2,906	276	38,088	4,587
Hawaii	—	768	—	768	2,525	303	2,828	—	—	1,681
Iowa	—	2,114	—	2,114	—	9	9	6	9,554	1,529
Idaho	—	171	—	171	32	—	32	—	8,535	633
Illinois	—	31,786	—	31,786	654	274	928	124	75,088	24,089
Indiana	—	2,250	—	2,250	583	38	621	—	38,380	706,749
Kansas	—	—	—	—	—	2	2	—	2,034	—
Kentucky	—	5,150	—	5,150	—	48	48	—	2,918	54
Louisiana	—	5,763	—	5,763	110	32	142	554	273,202	58,576
Massachusetts	—	4,083	—	4,083	14,168	549	14,717	—	97,327	7,998
Maryland	—	3,999	—	3,999	1,557	166	1,723	—	10,615	14,668
Maine	—	356	—	356	7,163	265	7,429	28	29,202	6,150
Michigan	—	1,291	—	1,291	168	50	218	215	102,184	15,825
Minnesota	—	1,934	—	1,934	51	55	105	—	16,424	4,226
Missouri	—	420	—	420	—	12	12	—	544	473
Mississippi	—	—	—	—	34	33	67	—	33,199	1,638
Montana	251	9,817	—	10,068	8	46	54	271	2,876	934
North Carolina	—	2,831	—	2,831	2,178	243	2,422	—	4,220	3,376
North Dakota	—	336	—	336	99	—	99	—	93	2,292
Nebraska	—	81	—	81	—	3	3	—	637	423
New Hampshire	—	—	—	—	149	76	225	—	2,903	4,099
New Jersey	—	2,114	—	2,114	519	1,240	1,758	—	152,934	22,090
New Mexico	—	—	—	—	—	113	113	—	17,492	142
Nevada	—	—	—	—	—	—	—	—	41,017	—
New York	44	8,958	—	9,002	6,042	1,000	7,042	53	299,560	16,976
Ohio	—	2,090	—	2,090	126	35	161	—	15,383	105,345
Oklahoma	—	1,568	—	1,568	92	—	92	—	20,359	5,234
Oregon	—	47	—	47	46	22	68	—	37,182	777
Pennsylvania	7,751	31,359	—	39,109	1,834	3,117	4,951	107	36,374	85,128
Rhode Island	—	—	—	—	364	21	385	—	48,989	2,720
South Carolina	—	605	—	605	729	68	797	—	7,728	1,626
South Dakota	—	—	—	—	—	—	—	—	—	—
Tennessee	—	2,238	—	2,238	66	1	67	—	13,474	5,805
Texas	—	—	2,697	2,697	627	365	992	709	862,084	183,449
Utah	476	14	—	490	—	3	3	—	2,374	44,154
Virginia	—	4,391	—	4,391	831	763	1,594	—	30,543	5,192
Vermont	—	—	—	—	3	—	3	—	—	441
Washington	—	4,229	—	4,229	502	336	838	—	47,504	5,847
Wisconsin	—	1,718	—	1,718	483	131	614	120	21,143	5,679
West Virginia	854	771	—	1,625	117	—	117	—	7,879	81,826
Wyoming	—	510	—	510	94	5	99	—	4,910	1,975
U.S. Total	**9,380**	**143,872**	**2,814**	**156,066**	**62,091**	**11,929**	**74,021**	**3,537**	**3,633,650**	**1,666,166**

1 Includes anthracite silt stored off-site.
2 Includes subbituminous coal.
Notes: • Data are final. • Totals may not equal sum of components because of independent rounding. • Mcf = Thousand Cubic Feet.
Source: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table 56. U.S. Nonutility Electricity Supply and Disposition for Generating Facilities by Census Division and State, 1999 and 2000

(Million Kilowatthours)

Census Division and State	Gross Generation		Receipts[2]		Sales[3]		Facility Use	
	1999 R	2000	1999 R	2000	1999 R	2000	1999 R	2000
New England	**69,265**	**82,353**	**3,399**	**3,042**	**58,712**	**71,691**	**13,953**	**13,704**
Connecticut	8,585	16,918	321	489	7,590	13,110	1,316	4,297
Maine	12,064	14,724	1,343	1,298	8,670	10,708	4,737	5,314
Massachusetts	38,703	41,076	1,399	838	33,212	38,881	6,890	3,033
New Hampshire	2,378	2,401	228	273	1,952	1,987	654	687
Rhode Island	6,547	6,218	104	115	6,346	6,025	304	308
Vermont	989	1,016	5	30	941	980	52	66
Middle Atlantic	**105,111**	**213,123**	**4,487**	**5,382**	**93,450**	**196,855**	**16,181**	**21,651**
New Jersey	18,568	34,361	913	862	16,590	31,898	2,913	3,325
New York	51,505	67,847	1,486	1,465	47,706	63,089	5,297	6,224
Pennsylvania	35,039	110,915	2,088	3,055	29,154	101,868	7,972	12,102
East North Central	**43,664**	**101,809**	**17,976**	**19,262**	**27,395**	**82,620**	**34,246**	**38,451**
Illinois	14,252	68,969	5,446	6,407	10,110	61,674	9,589	13,702
Indiana	7,996	8,494	4,618	5,141	2,783	3,681	9,831	9,955
Michigan	15,877	15,271	1,832	1,568	13,244	12,606	4,466	4,232
Ohio	1,507	4,903	3,184	3,246	74	3,307	4,617	4,842
Wisconsin	4,032	4,172	2,895	2,901	1,184	1,352	5,744	5,720
West North Central	**7,073**	**7,647**	**5,744**	**5,436**	**3,031**	**3,662**	**9,785**	**9,421**
Iowa	1,858	1,993	2,020	2,063	556	712	3,323	3,345
Kansas	69	52	1,092	1,133	22	15	1,139	1,170
Minnesota	4,569	5,005	2,207	1,820	2,428	2,907	4,348	3,918
Missouri	332	332	259	258	25	27	566	563
Nebraska	78	67	58	68	—	—	136	135
North Dakota	166	197	108	95	1	1	273	291
South Dakota	—	—	—	—	—	—	—	—
South Atlantic	**55,277**	**80,136**	**16,267**	**16,475**	**32,406**	**56,876**	**39,138**	**39,735**
Delaware	657	1,940	376	673	27	1,372	1,007	1,241
District of Columbia	—	50	—	—	—	46	—	4
Florida	21,410	23,114	2,002	2,014	13,954	15,526	9,459	9,602
Georgia	7,206	8,134	3,143	2,895	1,365	2,272	8,984	8,756
Maryland	2,480	20,120	1,818	1,727	1,814	18,559	2,484	3,287
North Carolina	7,916	8,311	3,722	3,880	5,631	6,353	6,007	5,837
South Carolina	3,069	3,074	582	599	1,295	1,372	2,357	2,302
Virginia	9,352	12,059	3,086	3,098	7,035	9,949	5,403	5,207
West Virginia	3,186	3,336	1,536	1,590	1,284	1,428	3,438	3,498
East South Central	**25,579**	**26,822**	**8,971**	**9,022**	**13,168**	**14,486**	**21,381**	**21,357**
Alabama	7,165	6,771	3,629	3,247	1,023	774	9,772	9,244
Kentucky	11,804	12,471	—	7	10,851	11,313	952	1,165
Mississippi	2,776	3,885	2,111	2,179	288	1,467	4,598	4,597
Tennessee	3,833	3,695	3,231	3,589	1,006	932	6,058	6,351
West South Central	**101,861**	**127,787**	**21,843**	**22,170**	**41,124**	**64,513**	**82,522**	**85,444**
Arkansas	2,566	2,553	860	856	46	35	3,380	3,374
Louisiana	25,893	36,858	7,727	7,636	4,300	13,823	29,312	30,671
Oklahoma	4,875	4,424	1,249	1,389	3,614	2,891	2,509	2,923
Texas	68,528	83,952	12,007	12,288	33,164	47,764	47,321	48,476
Mountain	**16,799**	**37,432**	**4,101**	**3,837**	**14,039**	**33,823**	**6,861**	**7,453**
Arizona	832	849	256	267	434	444	654	673
Colorado	3,444	4,242	160	155	3,262	4,007	342	390
Idaho	2,043	1,868	1,146	1,137	1,906	1,718	1,283	1,286
Montana	3,959	21,068	403	416	3,710	20,279	652	1,206
Nevada	4,158	6,436	2	1	3,823	6,060	337	378
New Mexico	891	1,194	1,393	960	497	645	1,786	1,515
Utah	763	837	464	583	389	419	838	1,001
Wyoming	709	938	277	318	18	252	968	1,004
Pacific	**119,932**	**151,217**	**7,607**	**10,531**	**100,236**	**135,662**	**27,346**	**26,087**
Alaska	1,231	1,261	121	103	337	232	1,014	1,131
California	104,089	126,925	3,492	3,851	88,144	112,735	19,473	18,042
Hawaii	4,146	4,310	29	27	3,473	3,648	702	689
Oregon	5,286	5,920	695	669	4,619	5,217	1,362	1,372
Washington	5,181	12,800	3,270	5,881	3,662	13,829	4,795	4,852
U.S. Total	**544,561**	**828,325**	**90,395**	**95,158**	**383,560**	**660,189**	**251,413**	**263,302**

1 R = Revised data.
2 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
3 Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in this data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-860B is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures attribute to the disparity.

Notes: •All data are for 1 megawatt and greater. •Data are final. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Appendix A

Technical Notes

Appendix A

Technical Notes

Sources of Data

The *Electric Power Annual Volume II* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy (DOE). Data published in the *Electric Power Annual Volume II* are compiled from seven forms filed annually by electric utilities and one form filed annually by nonutility power producers. Those forms are: the Form EIA-861, “Annual Electric Utility Report”; the Federal Energy Regulatory Commission (FERC) Form 1, “Annual Report of Major Electric Utilities, Licensees, and Others”; the Form EIA-412, “Annual Report of Public Electric Utilities”; the Form EIA-767, “Steam-Electric Plant Operation and Design Report”; the Form EIA-860A, “Annual Electric Generator Report - Utility”; the Form EIA-860B, “Annual Electric Generator Report - Nonutility”; the Department of Energy, Office of Emergency Planning Form EIA-411, “Coordinated Bulk Power Supply Program Report”; and the Department of Energy, Office of Fuels Programs, Fossil Energy Form FE-781R, “Annual Report of International Electric Export/Import Data.” Each form is summarized below.

Form EIA-861

The Form EIA-861 is a mandatory census of electric utilities in the United States, its territories, and Puerto Rico. The Form EIA-861 data contained in this publication are for the United States only. The survey is used to collect information on power production and sales of electricity and demand-side management information from approximately 3,300 electric utilities. The data collected are used to update the electric utility frame data base maintained by the EIA. This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary data from the Form EIA-861 are also contained in the *Electric Power Monthly;* the *Electric Sales and Revenue;* the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities;* the *Annual Energy Outlook; Electric Trade in the United States*, and, for 1994 through 1996, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* and *U.S. Electric Utility Demand-Side Management.* These reports present aggregate totals for electric utilities on national, State, and regional levels by ownership type.

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

Data Processing. The Form EIA-861 is mailed to the respondents to collect data as of the end of the calendar year. The completed forms are to be returned to the EIA by April 30. The data are 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, “Monthly Electric Utility Sales and Revenue Report with State Distributions,” the FERC Form 1, and the Form EIA-412. These are utility-level checks. Respondents are telephoned to obtain clarification of reported data and to obtain missing data.

FERC Form 1

The FERC Form 1 is a mandatory restricted-universe census of major investor-owned electric utilities in the United States having, in each of the last three consecutive years, sales or transmission service that exceeds one or more of the following: (1) 1 million megawatthours of total annual sales, (2) 100 megawatthours of annual sales for resale, (3) 500 megawatthours of annual power exchanges delivered, or (4) 500 megawatthours of annual wheeling for others (deliveries plus losses). All major U.S. investor-owned electric utilities, licensees, or others subject to the Federal Power Act of 1935 must submit this form annually to the FERC. Classification of such entities is provided in the FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Approximately 179 electric utilities are classified as major. Excluded from the summary data are the independent power producers and cooperatives jurisdictional to the FERC.

The FERC Form 1 is used to collect data on income and earnings, taxes, depreciation and amortization, distribution of salaries and wages, electric operating revenues, electric maintenance expenses, generating plant statistics, planned construction data, year-end balance sheets, and general corporate information. Respondents are required to report data on historical plant cost and power production expenses for their hydroelectric plants with a generator nameplate capacity of 10 or more megawatts; each steam-electric plant with a generator nameplate capacity of 25 or more megawatts; and each gas-turbine plant with a generator nameplate capacity of 10 or more megawatts. Less detailed data are required for other plants.

This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary and detailed data from the FERC Form 1 are also contained in the *State Energy Data Report;* the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities* (through 1996 only); the *State Energy Price and Expenditure Report;* the *Annual Energy Review;* and the *Electric Trade in the United States.* These reports present aggregate totals for electric utilities on a national level, by State, and by ownership type.

Instrument and Design History. The Federal Power Commission's (FPC) Form 1, the predecessor of the FERC Form 1, was implemented in 1935 by the FPC. When the FPC was merged with the DOE in October 1977, the processing of data on the survey became the responsibility of the EIA. In 1991, the collection responsibility reverted to the FERC. This mandatory survey is conducted in accordance with the FERC *Uniform System of Accounts Prescribed for Private Utilities and Licensees.*

Data Processing. The completed surveys, both hard copy and diskettes, are returned to the FERC on or before April 30, containing data for the preceding calendar year. A copy of each survey and diskette is forwarded to the EIA for processing. Manual editing of the reported data is completed prior to data entry. Additional edit checks of the data are performed through computer programs. The program edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, are resolved either by the processing office or by further information obtained from a telephone call to the respondent company. Effective for 1997 through 1999, FERC Form 1 data have been edited by Navigant Consulting, Inc.

Form EIA-412

The Form EIA-412 is a restricted-universe census used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Those publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had 150,000 megawatthours of sales to ultimate consumers and/or 150,000 megawatthours of sales for resale for the 2 previous years, as reported on the Form EIA-861, "Annual Electric Utility Report," must submit the Form EIA-412. The 1996-1997 data represents those electric utilities meeting a threshold of 120,000 megawatthours ultimate consumers' sales and or resales. The criteria used to select the respondents for this survey results in approximately 500 publicly owned electric utilities.

Federal electric utilities are required to file the Form EIA-412. The financial data for the U.S. Army Corps of Engineers (except for Saint Mary's Falls at Sault Ste. Marie, Michigan); the U.S. International Boundary and Water Commission; and the U.S. Department of Interior, Bureau of Reclamation were collected on the Form EIA-412 from the Federal power marketing administrations.

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

This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary and detail data from the Form EIA-412 are also contained in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities;* the *State Energy Price and Expenditure Report;* the and the *Electric Trade in the United States.* These reports present aggregate totals for electric utilities on a national level, by State, and by ownership type.

Data Processing. The processing of data reported on this survey is the responsibility of the Electric Power Division within the Office of Coal, Nuclear, Electric and Alternate Fuels. The completed surveys are due in this office on or before April 30. Nonresponse follow-up procedures are used to attain 100-percent response. Manual editing of the reported data is completed prior to data entry. Additional edit checks of the data are performed through computer programs. The program edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, are resolved either by the processing office or by further information obtained from a telephone call to the respondent company.

Form EIA-767

The Form EIA-767 is a mandatory restricted-universe census of all electric power plants with a total existing or planned organic- or nuclear-fueled steam-electric generator nameplate rating of 10 or more megawatts. The entire form is filed by approximately 700 power plants with a nameplate capacity of 100 or more megawatts. An additional 200 power plants with a nameplate capacity between 10 and 100 megawatts submit information only on fuel consumption/quality, boiler/generator configuration, and flue-gas desulfurization equipment, if applicable. The Form EIA-767 is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data). Data from the Form EIA-767 are used for economic, regulatory, and environmental analyses conducted by the DOE and the Environmental Protection Agency.

This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. These reports present aggregate totals for electric utilities on a national level, by State, and by ownership type.

Instrument and Design History. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, "Steam-Electric Plant Air and Water Quality Control Data," was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and given the name Form EIA-767, "Steam-Electric Plant Operation and Design Report." In 1986, the respondent universe of 700 was increased to 900 to include plants with nameplate capacity from 10 megawatts to 100 megawatts. Respondents for these 200 additional plants complete only pages 1, 5, 6, and, if applicable, 13, and 14.

Data Processing. The Form EIA-767 is mailed to respondents in January to collect data as of the end of the preceding calendar year. The completed forms are to be returned to the EIA by May 1. Equipment design data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually reviewed before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process.

Form EIA-860A

The Form EIA-860A is a mandatory census of electric utilities in the United States that operate power plants or plan to operate a power plant within 5 years of the reporting year. The survey is used to collect data on existing power plants from the electric utilities and their 5-year plans for constructing new plants, and modifying and retiring existing plants. Data on the survey are collected at the generating unit level. These data are then aggregated by energy source, geographic area, and prime mover. Final data from the Form EIA-860A are also summarized in the *Inventory of Electric Utility Power Plants in the United States.*

Instrument and Design History. The Form EIA-860A was implemented in January 1999 to collect data as of January 1, 1999. Form EIA-860A replaced Form EIA-860. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-860A is mailed to approximately 900 respondents in December of each year and the completed forms are to be returned to the EIA by February 15 containing data as of January 1 of the following year. Respondents have the option of filing Form EIA-860A directly with the EIA or through an agent such as the respondent's regional electric reliability council. Data reported through the regional electric reliability councils are submitted to the EIA electronically from the North American Electric Reliability Council (NERC). Data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually edited 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. After EIA approval, the data are made available for public use.

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 5 additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; and (5) bulk power system maps. These data support queries from the executive branch, Congress, other public agencies, and the general public. These reports present various 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. The Form EIA-411 is filed annually on June 1 by the 10 North American Electric Reliability Councils. The forms are compiled from data furnished by electric utilities and nonutilities (members, associates, and for nonmembers) within the council areas.

Form FE-781R

The Form FE-781R, "Annual Report of International Electrical Export/Import Data" is used to collect on an annual basis, monthly information on the gross amounts of electrical energy received and delivered and the costs and revenue associated with these transactions. The use of the format contained in Form FE-781R is optional for reporting purposes; however, submission of the data is mandatory.

Instrument and Design History. The authority to issue presidential permits pursuant to Executive Order Number 10485 was transferred to the Secretary of Energy by Executive Order Number 12038 (43 FR 4957 February 7, 1987). This responsibility was delegated by the Secretary to the Economic Regulatory Administration (DOE Delegation Order Number 0204-04, October 1, 1977). The authority was redelegated (DOE Delegation Order Number 127) to the Office of Fuels Programs, Fossil Energy, (54 FR 11436 March 20, 1990). The survey universe is defined under Title 10 of the Code of Federal Regulations, Sections 205.308 and 205.325 to include all public utilities or other entities subject to the Department of Energy jurisdiction under Part II of the Federal Power Act engaged in the export of electric energy across the international borders of the United States with Canada and Mexico. It also includes those engaged in the transmission of electrical energy across these borders who hold a presidential permit.

The methodology has been modified for calculating import and export data for Canada by basing on metered energy and include both firm and interruptible energy. Originally collected from presidential permits, the data are now obtained from the National Energy Board of Canada. This became effective in 1998. However, the methodology was adapted to 1995 through 1997 data. The methodology for Mexico remains the same.

Data Processing. The Form FE-781R is mailed to the respondents to collect annually, the monthly data for the preceding calendar year. The completed forms are to be returned to the DOE by February 15. The receipts are manually edited and the data used for the Presidential Permit Program are entered into a machine readable format.

Form EIA-860B

In 1998, the Form EIA-867, "Annual Nonutility Power Producer Report," was renamed Form EIA-860B, "Annual Electric Generator Report - Nonutility." The Form EIA-860B is 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. 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. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a contract for the electric energy, or (3) financial closure on the facility. The Form consists of Schedules I, "Identification and Certification;" Schedule II, "Facility Information"; Schedule III, "North American Industry Classification System"; Schedule IVA, "Facility Fuel Information"; Schedule IVB, "Facility Thermal and Generation Information"; Schedule V, "Facility Environmental Information"; and Schedule VI, "Electric Generator Information."

Submission of the Form EIA-860B is required from all facilities that have a combined facility nameplate capacity of 1 megawatt or more. Schedule V, "Facility Environmental Information" is only required of those facilities of 25 megawatts or more.

The form is used to collect data on the installed capacity, energy consumption, generation, and electric energy sales to electric utilities and other nonutilities by facility. Additionally, the form is used to collect data on the quality of fuels burned and the types of environmental equipment used by the respondent.

Instrument and Design History. The Form EIA-867 was implemented in December 1989 to collect data as of year-end 1989. In 1998, the Form EIA-867 "Annual Nonutility Power Producer Report," form number and name has been changed to Form EIA-860B, "Annual Electric Generator Report - Nonutility." The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-860B is mailed to the respondents in January to collect data as of the end of the preceding calendar year. Static data for each respondent are preprinted from the previous year, and the respondents are instructed to verify all preprinted information and to supply the missing data. The completed forms are to be returned to the EIA by April 30. The response rate for all facilities for which addresses were confirmed was 100 percent. The data are manually edited before being keyed for automated data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain corrections or clarifications of reported data and to obtain missing data as a result of the manual and automated editing.

Data Quality. The Manufacturing Energy Consumption Survey (MECS) produces detailed estimates of manufacturing electricity generation by industry and Census Division on a triennial basis. The data are published in the *Manufacturing Energy Consumption Survey, Consumption of Energy*. Gross generation by nonutility power producers by major industry groups, and Census division, for 1996 through 1999 presented in this report, are reasonable given the growth in manufacturing on site generation.

Data for the Form EIA-860B are collected from all existing and planned nonutility generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. These data are aggregated to provide geographic totals for selected States and at the Census division and national levels. The Form EIA-867 data are considered confidential (1996 through 1997). Therefore, suppression of some data is necessary to protect the confidentiality of the individual respondent data. See "Confidentiality of the Data" in this section for further information on the nondisclosure of data. In 1998 and 1999, the Form EIA-860B data that are confidential are planned units that have sales to other end-users.

Allocating Capacity. The installed capacity for nonutility generating units is allocated to one energy source using the following algorithms:

- For generating units using a single fossil energy source, the capacity is allocated totally to that energy source.
- For generating units that use hydraulic, geothermal, solar, biomass, or wind energy, the capacity is allocated to that energy source (even if a secondary fuel is burned).
- For generating units using a combination of fossil energy and renewable energy sources, capacity is classified as fossil or renewable based on the greatest percentage of Btu consumed when summed.
- To allocate capacity by fuel within the fossil energy and renewable energy sources, the single fuel within that energy source with the greatest percentage of Btu consumed is used.

Allocating Generation. The generation for nonutility facilities is allocated to one energy source using the following algorithms:

- For generating units that use energy sources that are not burned (hydraulic, geothermal, nuclear, solar, or wind energy), the generation is allocated to that energy source.
- For facilities having generating units using energy sources that are burned, the generation is allocated based on the percentage of Btu consumed. This algorithm assumes that unit efficiency is the same for all energy sources.

Gross-to-Net Generation Conversion Methodology. Gross electricity generation data from the Form EIA-860B, reported by generator, are aggregated to provide totals by energy source and geographic area. Nonutility power producers report gross electricity generated on the Form EIA-860B, unlike electric utilities that report net generation on various EIA and FERC forms. Nonutilities generally do not measure and record electrical consumption used solely for the production of electricity. Nonutility generators and associated auxiliary equipment are often an integral part of a manufacturing or other industrial process and individual watthour meters are not generally installed on auxiliary equipment.

Estimated values for net generation from nonutility power producers were developed by EIA using gross generation, prime mover, fuels, and type of air pollution control data reported on the Form EIA-860B. The difference between gross and net generation--sometimes called parasitic load--is the electricity consumed by auxiliary equipment and environmental control devices such as pumps, fans, coal pulverizers, particulate collectors, and flue gas desulfurization (FGD) units. In smaller power plants rotating auxiliaries are almost always electric motors. In large power plants that produce steam, rotating auxiliaries can be powered by either steam turbines or electric motors and sometimes both because of cold startup requirements.

This methodology for estimating net generation from gross generation is based on determining typical energy consumption for auxiliary electrical equipment associated with electrical generators. For instance, wind turbines have none of the auxiliaries common to a coal-burning power plant such as coal pulverizers, fans, and emission controls. On the other hand, windfarms consume electricity since automatic, computer-based systems control blade pitch and speed, thereby affecting generator electricity output.

Shown below are the conversion factors used to estimate net generation by nonutility generators. The factors are typical of a modern electric power plant but could vary significantly between individual plants. Net generation is calculated by multiplying the appropriate conversion factor by the reported gross electrical generation.

Prime Mover Type	Gross-to-Net Generation Conversion Factor
Gas (Combustion) Turbine	.98
Steam Turbine	.97[a]
Internal Combustion	.98
Wind Turbine	.99
Solar-Photovoltaic	.99
Hydraulic Turbine	.99
Fuel Cell	.99
Other	.97

[a]Factor reduced by .01 if the facility has flue gas particulate collectors and another .03 if the facility has flue gas desulfurization (FGD) equipment. Facilities under 25 megawatts and burning coal in traditional boilers (e.g., not fluidized bed boilers) are assumed to have particulate and FGD equipment.

These conversion factors were estimated by the staff of the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration. The primary reference used in developing the conversion factors was *Steam, Its Generation and Use*, 40th Edition, Babcock & Wilcox, Barberton, Ohio.

Emissions for the Production of Electricity Methodology. Emissions for nonutility power producers include emissions from cogeneration 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 cogeneration facilities. The methodology is based on the following:

1. A steam boiler efficiency rate of 80 percent was assumed.[16]

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.

Net generation heat rates by primary fuel and prime mover are as follows:

Prime Mover	Heat Rate (Btu/kWh - net) By Primary Fuel			
	Coal	Petroleum	Natural Gas	Other
Gas (Combustion Turbine)				
Single Cycle	N/A	14,000	14,500	N/A
Combined Cycle	N/A	8,100	8,200	N/A
Steam Turbine				
Single Cycle	10,200	9,600	9,600	16,500
Combined Cycle	9,000	9,000	9,000	10,500
Internal Combustion	N/A	11,700	11,700	N/A
Other	10,200	11,700	11,700	10,500

Nameplate Capacity to Summer Capability Conversion Methodology. Form EIA-860B, "Annual Electric Generator Report – Nonutility," collects nameplate capacity for electric generating units. Estimated values for net summer capability from nameplate capacity are aggregated to provide a U.S. total. The methodology used for estimating summer capability from nameplate capacity is based on data submitted for the Form EIA-860A.

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.[17] In 1997, the SIC Manual name was changed to North American Industry Classification System (NAICS). The following is a list from the Form EIA-860B of the main classifications and the category of primary business activity within each classification.

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

[17] Office of Management and Budget, *Standard Industrial Classification Manual, 1972* (Washington, DC, 1987).

Agriculture, Forestry, and Fishing
111 Agriculture production-crops
112 Agriculture production, livestock and animal specialties
115 Agricultural services
113 Forestry
114 Fishing, hunting, and trapping

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

92 Public Administration
92

Other (explain):

Historically, (Tables 49 and 53) show cogeneration facilities reporting the Standard Classification Code (SIC) that identified the user of the electric and/or thermal energy. Beginning in 1993, the SIC code was broadened to include the SIC code(s) of the producing facility based on the facilities consumption. This revision provides an alternative method of comparing power needs and utilization within the nonutility power industry. Since 1998, all the tables are based on North American Industry Classification System. Tables A1 and A2 show the installed capacity and gross generation of electricity by the producing energy group, respectively.

Quality of Data

The Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF) is responsible for routine data improvement and quality assurance activities. All operations in this office are done in accordance with formal standards established by the EIA. These standards are the measuring rod necessary for quality statistics. Data improvement efforts include verification of data-keyed input by automatic computerized methods, editing by subject matter specialists, and follow up on nonrespondents. The CNEAF office supports the quality assurance efforts of the data collectors by providing advisory reviews of the structure of information requirements, and of proposed designs for new and revised data collection forms and systems. Once implemented, the actual performance of working data collection systems is also validated. Computerized respondent data files are checked to identify those who fail to respond to the survey. By law, nonrespondents may be fined or otherwise penalized for not filing a mandatory EIA data form. Before invoking the law, the EIA tries to obtain the required information by encouraging cooperation of nonrespondents.

Completed forms received by the CNEAF office are sorted, screened for completeness of reported information, and keyed onto computer tapes for storage and transfer to random access data bases for computer processing. The information coded on the computer tapes is manually spot-checked against the forms to certify accuracy of the tapes. To ensure the quality standards established by the EIA, formulas that use the past history of data values in the data base have been designed and implemented to check data input for errors automatically. Data values that fall outside the ranges prescribed in the formulas are verified by telephoning respondents to resolve any discrepancies.

Data Editing System

Data from the form surveys are edited using automated systems. The edit includes both deterministic checks, in which records are checked for the presence of required fields and their validity; and statistical checks, in which estimation techniques are used to validate data according to their behavior in the past and in comparison to other current fields.

Confidentiality of the Data

In general, the 1998 and 1999 data collected on the forms used for input to this report are not confidential. However, data from the Form EIA-867, "Annual Nonutility Power Producer Report, (1996-1997)" are considered confidential and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45 *Federal Register* 59812 (1980)). In order to protect the confidentiality of individual respondent's data, a procedure was developed to suppress the data for publication. The procedure is described as follows.

Disclosure of Data

Certain data reported on the Form EIA-860B, "Annual Electric Generator Report - Nonutility," are confidential. In order to protect the confidentiality of data for an individual respondent, a policy was implemented to ensure that the reporting of survey data would not associate those data with a particular company. The final phase in the data quality assurance and control procedures is to determine which data must be suppressed (withheld) during publication to provide the necessary confidentiality for respondents that operate in small reporting areas. These procedures are performed as follows:

- Primary Withholding Based on the Number of Respondents in a Cell--All cells with three or fewer respondents are suppressed.
- Residual Withholding Dominance Rule--All cells containing four or more respondents are tested using a linear sensitivity rule.
- Complementary Suppression--All tables are reviewed to identify cells that should have data withheld to prevent disclosure of already suppressed cells. An example of this concept, when U.S. totals are available, would be the complementary suppression of a second State in order to prevent the derivation of an initially suppressed State.

The withholding/suppression of data is performed as an adjunct to Quality Assurance (QA) procedures. The work is performed by survey editors and the QA staff and is reviewed by the survey manager before being submitted to the division level QA review.

All sensitive cells identified in the withholding analysis are denoted with the symbol/letter "W." The use of the symbol/letter applies to primary, complementary and inter-table suppressions as well as all withheld data.

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 rounded number truncated to zero is (*).

CNEAF Data Revision and Policy

The Office of Coal, Nuclear, Electric and Alternate Fuels has adopted the following policy with respect to the revision and correction of recurrent data in energy publications:

1. Annual survey data collected by this office are published either as preliminary or final when first appearing in a data report. Data initially released as preliminary will be so noted in the report. These data will be revised, if necessary, and declared final in the next publication of the data.
2. All monthly and quarterly survey data collected by this office are published 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 approved by the Office Director.
3. The magnitude of changes due to revisions experienced in the past will be included in the data reports, so that the reader can assess the accuracy of the data.
4. After data are published as final, corrections will be made only in the event of a greater than one percent difference at the national level. Corrections for differences that are less than the before-mentioned threshold are left to the discretion of the Office Director.

The *Electric Power Annual Volume II* 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:

- **U.S. Electric Utility Retail Sales and Revenue** Data on sales, revenue, and average revenue per kilowatthour from the Form EIA-861 for 1999 are final.
- **U.S. Electric Utility Financial Statistics** Financial data from the Federal Energy Regulatory Commission Form 1 for 1999 are preliminary and the Form EIA-412 for 1999 are final.
- **U.S. Electric Utility Environmental Statistics** Data from the Form EIA-767 for 1999 are final pending approval of the Environmental Protection Agency.
- **U.S. Electric Power Transactions** All data from the Forms EIA-411, EIA-860A, and EIA-861 are final. Data from the Form FE-781R are final.
- **U.S. Electric Utility Demand-Side Management** All data on demand-side management from the Form EIA-861 are final.
- **U.S. Nonutility Power Producers** Data from the Form EIA-867 for 1996 through 1997 are final. Data from Form EIA-860B for 1998 through 2000 are final.

Formulas and Calculations

Average Heat Content

In order to determine the Btu value per unit of consumption for each of the fossil fuels collected on the Form EIA-759, the heat content values contained on the FERC Form 423 were used. Data on the FERC Form 423 represent approximately 85 percent of the total generator nameplate capacity for all electric utilities.

Percent Difference

The following formula is used to calculate percent differences.

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

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

Form EIA-861

Data for the Form EIA-861 are collected at the utility 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. These data are then aggregated to provide geographic totals at the State, NERC region, Census division, and national level. Sources and disposition of data are also provided by utility class of ownership and retail consumer class of service. Average revenue (nominal dollars) per kilowatthour of electricity sold is calculated by dividing total annual retail revenue (nominal dollars) by the total annual retail sales of electricity.

Average revenue per kilowatthour is defined as the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average revenue per kilowatthour is calculated for all consumers and for each sector (residential, commercial, industrial, and other sales).

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 utility for providing electrical service. The average revenue per kilowatthour reported in this publication by sector represents a weighted average of consumer revenue and sales within that sector and across sectors for all consumers.

The electric revenue used to derive the average revenue per kilowatthour is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges.

Electric utility operating revenues cover, among other costs of service, State and Federal income taxes and taxes other than income taxes paid by the utility. The Federal component of these taxes are, for the most part, "payroll" taxes. State and local authorities tax the value of plant (property taxes), the amount of revenues (gross receipts taxes), purchases of materials and services (sales and use taxes), and a potentially long list of other items that vary extensively by taxing authority. Taxes deducted from employees' pay (such as Federal income taxes and employees' share of social security taxes) are not a part of the utility's "tax costs," but are paid to the taxing authorities in the name of the employees. These taxes are included in the utility's cost of service (for example, revenue requirements) and are included in the amounts recovered from consumers in rates and reported in operating revenues.

Electric utilities, like many other business enterprises, are required by various taxing authorities to collect and remit taxes assessed on their consumers. In this regard, the electric utility serves as an agent for the taxing authority. Taxes assessed on the consumer, such as a sales tax, are called "pass through" taxes. These taxes do not represent a cost to the utility and are not recorded in the operating revenues of the utility. However, taxing authorities differ as to whether a specific tax is assessed on the utility or the consumer--which, in turn, determines whether or not the tax is included in the operating revenue of the electric utility.

EIA collects Demand-Side Management (DSM) information from all utilities with DSM programs. Utilities with sales to ultimate consumers or sales for resale greater than or equal to 150,000 megawatthours (120,000 megawatthours prior to 1998) report their incremental peak load reductions, energy savings, direct and indirect utility costs attributable to DSM programs, annual peak load reductions, and energy savings for the reporting year. Annual and incremental effects for the reporting year are reported by consumer sector (residential, commercial, industrial, other) for each program category (energy efficiency and load management). Utilities with sales to ultimate consumers and sales for resale less than 150,000 megawatthours (120,000 megawatthours prior to 1998) report incremental peak load reductions and energy savings. They also report total utility cost for the reporting year.

FERC Form 1

Composite Financial Indicators for Major Investor-Owned Electric Utilities

All financial monetary data in this report are expressed in nominal terms. The following formulas are used to calculate composite financial indicators.

Electric Fixed Asset (Net Plant) Turnover =

$$\frac{\sum_i (EOR_i)}{\sum_i (U_i)},$$

where EOR_i is the Electric Operating Revenue for the i^{th} major utility, and U_i is the Electric Utility Plant -- Net for the i^{th} major utility.

Total Asset Turnover =

$$\frac{\sum_i (OR_i)}{\sum_i (A_i)},$$

where OR_i is the Operating Revenue for the i^{th} major utility, and A_i are the Total Assets for the i^{th} major utility.

Current Assets to Current Liabilities =

$$\frac{\sum_i (CAA_i)}{\sum_i (CAL_i)},$$

where CAA_i are the Current and Accrued Assets for the i^{th} major utility, and CAL_i are the Current and Accrued Liabilities for the i^{th} major utility.

Long-term Debt to Capitalization =

$$\frac{\sum_i (LTD_i)}{\sum_i (C_i)} \times 100,$$

where LTD_i is the Long-term Debt for the i^{th} major utility, and C_i is the Capitalization for the i^{th} major utility.

Preferred Stock to Capitalization =

$$\frac{\sum_i (PS_i)}{\sum_i (C_i)} \times 100,$$

where PS_i is the Preferred Stock for the i^{th} major utility, and C_i is the Capitalization for the i^{th} major utility.

Common Stock Equity to Capitalization =

$$\frac{\sum_i (CSE_i)}{\sum_i (C_i)} \times 100,$$

where CSE_i is the Common Stock Equity of the i^{th} major utility; and, C_i is the Capitalization for the i^{th} major utility.

Total Debt to Total Assets =

$$\frac{\sum_i (LTD_i + STD_i)}{\sum_i (TA_i)} \times 100,$$

where LTD_i is the Long-term Debt of the i^{th} major utility; STD_i is the Short-term Debt of the i^{th} major utility; and, TA_i are the Total Assets of the i^{th} major utility.

Common Stock Equity to Total Assets =

$$\frac{\sum_i (CSE_i)}{\sum_i (TA_i)} \times 100,$$

where CSE_i is the Common Stock Equity of the i^{th} major utility; and, TA_i are the Total Assets of the i^{th} major utility.

Interest Coverage Before Taxes Without AFUDC =

$$\frac{\sum_i \left(\begin{matrix} IBI_i + EIT_i + GIT_i \\ + OUIT_i + TOID_i - AC_i \end{matrix} \right)}{\sum_i (IE_i)},$$

where IBI_i is Total Income Before Interest Charges for the i^{th} major utility; EIT_i are the Electric Income Taxes for the i^{th} major utility; GIT_i are the Gas Income Taxes for the i^{th} major utility; $OUIT_i$ are the Other Utility Income Taxes for the i^{th} major utility; $TOID_i$ are the Taxes for Other Income and Deductions for the i^{th} major utility; AC_i is the Allowance for Other Funds Used During Construction for the i^{th} major utility; and, IE_i is the Interest Expense for the i^{th} major utility.

Profit Margin =

$$\frac{\sum_i (NI_i)}{\sum_i (OR_i)} \times 100,$$

where NI_i is the Net Income of the i^{th} major utility; and,
OR_i is the Operating Revenue for the i^{th} major utility.

Return on Average Common Stock Equity =

$$\frac{\sum_i (NI_i)}{\left(\sum_i (CSEB_i) + \sum_i (CSEE_i) \right)} /2 \times 100,$$

where NI_i is the Net Income of the i^{th} major utility; $CSEB_i$ is the Common Stock Equity at Beginning of Year, for the i^{th} major utility, and $CSEE_i$ is the Common Stock Equity at End of Year for the i^{th} major utility.

Return on Investment =

$$\frac{\sum_i (NI_i)}{\sum_i (TA_i)} \times 100,$$

where NI_i is the Net Income of the i^{th} major utility; and,
TA_i are the Total Assets of the i^{th} major utility.

Form EIA-412

Composite Financial Indicators for Major Publicly Owned Electric

Utilities

Electric Utility Plant per Dollar of Revenue =

$$\frac{\sum_i (EUP_i)}{\sum_i (EOR_i)},$$

where EUP is the Electric Utility Plant for the the i^{th} public utility; and, EOR is the Electric Operating Revenue for the i^{th} public utility.

Current Assets to Current Liabilities =

$$\frac{\sum_i (CA_i)}{\sum_i (CL_i)},$$

where CA_i are the Current and Accrued Assets for the i^{th} public utility; and, CL_i are the Current and Accrued Liabilities for the i^{th} public utility.

Electric Utility Plant as a Percent of Total Assets =

$$\frac{\sum_i (EUP_i)}{\sum_i (TA_i)} \times 100,$$

where EUP_i is the Electric Utility Plant for the i^{th} public utility; and, TA_i are the Total Assets for the i^{th} public utility.

Net Electric Utility Plant as a Percent of Total Assets =

$$\frac{\sum_i (NEUP_i)}{\sum_i (TA_i)} \times 100,$$

where $NEUP_i$ is the Net Electric Utility Plant for the i^{th} public utility; and, TA_i is the Total Assets for the i^{th} public utility.

Debt as a Percent of Total Liabilities =

$$\frac{\sum_i (D_i)}{\sum_i (TL_i)} \times 100,$$

where D_i is the Debt for the i^{th} public utility; and, TL_i is the Total Liabilities for the i^{th} public utility.

Accumulated Provision for Depreciation as a Percent of Electric Utility Plant =

$$\frac{\sum_i (APD_i)}{\sum_i (EUP_i)} \times 100,$$

where APD_i is the Accumulated Provision for Depreciation for the i^{th} public utility; and, EUP_i is the Electric Utility Plant for the i^{th} public utility.

Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (EOME_i)}{\sum_i (EOR_i)} \times 100,$$

where $EOME_i$ is the Electric Operation and Maintenance Expenses for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Electric Depreciation and Amortization as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (EDA_i)}{\sum_i (EOR_i)} \times 100,$$

where EDA_i is Electric Depreciation and Amortization for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Taxes and Tax Equivalents as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (TTE_i)}{\sum_i (EOR_i)} \times 100,$$

where TTE_i are the Taxes and Tax Equivalents for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Interest Expense as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (IE_i)}{\sum_i (EOR_i)} \times 100,$$

where IE_i is the Interest Expense for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Net Income as a Percent of Electric Operating Revenues =

$$\frac{\sum_i (NI_i)}{\sum_i (EOR_i)} \times 100,$$

where NI_i is the Net Income of the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Purchase Power Cents Per Kilowatthour =

$$\frac{\sum_i (PPC_i)}{\sum_i (PPK_i)} \times 10, \qquad (A1)$$

where PPC_i is the Purchase Power Costs (in cents) for the i^{th} public utility; and, PPK_i is the Purchased Power Kilowatthours for the i^{th} public utility.

Generated Cents Per Kilowatthour =

$$\frac{\sum_i (TGC_i)}{\sum_i (TGK_i)} \times 10, \qquad (A2)$$

where TGC_i is the Total Generation Costs (in cents) for the i^{th} public utility; and, TGK_i is the Total Generated Kilowatthours for the i^{th} public utility.

Total Power Supply Per Kilowatthour Sold =

$$\frac{\sum_i (TPC_i)}{\sum_i (TPK_i)} \times 10, \qquad (A3)$$

where TPC_i is the Total Generation and Purchase Power Cost for the i^{th} public utility; and, TPK_i is the Total Generated and Purchased Power Kilowatthours Sold for the i^{th} public utility.

Table A1. Installed Capacity at U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1998 Through 2000

(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1998R			
New England	1,171	10,603	67	—	—	—	11,841
Middle Atlantic	1,706	10,994	105	—	1	18	12,824
East North Central	2,813	5,157	344	—	58	18	8,390
West North Central	753	613	135	203	—	11	1,715
South Atlantic	4,830	8,565	86	6	63	100	13,650
East South Central	2,042	2,282	14	26	11	—	4,376
West South Central	10,043	5,498	197	68	—	—	15,805
Mountain	407	2,070	53	241	9	118	2,899
Pacific	2,277	23,216	169	650	351	51	26,713
U.S. Total	**26,041**	**69,000**	**1,170**	**1,193**	**493**	**316**	**98,213**
				1999R			
New England	969	18,481	58	—	—	—	19,508
Middle Atlantic	1,335	33,672	73	2	—	18	35,101
East North Central	2,861	21,584	173	—	1,041	18	25,676
West North Central	546	1,204	109	203	—	11	2,073
South Atlantic	4,180	9,371	80	6	671	108	14,417
East South Central	1,733	4,286	14	26	11	—	6,070
West South Central	10,197	7,517	74	70	—	11	17,870
Mountain	326	5,904	51	237	9	17	6,543
Pacific	1,866	30,801	99	170	317	15	33,267
U.S. Total	**24,012**	**132,821**	**730**	**714**	**2,049**	**198**	**160,525**
				2000			
New England	1,312	22,018	65	—	—	—	23,395
Middle Atlantic	1,731	62,188	102	—	—	18	64,039
East North Central	2,949	28,514	311	—	6	15	31,795
West North Central	791	967	135	203	—	11	2,106
South Atlantic	4,781	24,844	83	6	63	107	29,883
East South Central	2,060	5,357	14	26	11	—	7,467
West South Central	11,262	16,324	197	67	—	11	27,862
Mountain	410	6,432	52	224	—	—	7,118
Pacific	2,423	31,653	158	628	29	38	34,929
U.S. Total	**27,719**	**198,297**	**1,115**	**1,154**	**108**	**200**	**228,594**

R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data are final; •See Technical Notes for North American Industry Classification System for these industry groups. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table A2. Gross Generation of U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1996 Through 2000

(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1998R			
New England	5,997	35,057	223	—	—	—	41,277
Middle Atlantic	9,312	56,854	444	—	7	71	66,688
East North Central	13,365	19,191	1,309	—	56	44	33,964
West North Central	3,375	1,436	322	1,146	—	21	6,299
South Atlantic	25,403	29,002	221	2	31	171	54,830
East South Central	11,886	6,022	92	124	56	—	18,181
West South Central	60,804	33,967	585	396	—	—	95,751
Mountain	2,139	10,424	237	492	57	395	13,744
Pacific	12,281	74,453	850	4,100	410	157	92,252
U.S. Total	**144,562**	**266,406**	**4,283**	**6,261**	**615**	**858**	**422,985**
				1999R			
New England	4,674	64,366	220	—	—	—	69,260
Middle Atlantic	7,181	95,239	314	—	—	69	102,803
East North Central	13,021	29,607	596	—	440	(*)	43,664
West North Central	2,454	3,276	298	1,024	—	20	7,073
South Atlantic	22,191	32,476	195	2	217	196	55,277
East South Central	10,581	14,736	96	117	53	—	25,584
West South Central	58,678	42,666	153	369	—	(*)	101,865
Mountain	1,565	16,757	235	498	57	—	19,112
Pacific	9,203	108,995	409	1,099	187	31	119,924
U.S. Total	**129,547**	**408,118**	**2,517**	**3,109**	**955**	**317**	**544,561**
				2000			
New England	5,856	76,246	252	—	—	—	82,353
Middle Atlantic	9,411	203,163	478	—	—	70	213,123
East North Central	13,325	87,329	1,138	—	17	1	101,809
West North Central	3,590	2,494	402	1,148	—	13	7,647
South Atlantic	23,825	55,872	214	2	30	192	80,136
East South Central	11,899	14,676	74	115	57	—	26,822
West South Central	67,163	59,705	562	356	—	(*)	127,787
Mountain	2,068	34,473	226	664	—	—	37,432
Pacific	12,326	134,006	730	3,877	138	140	151,217
U.S. Total	**149,463**	**667,966**	**4,076**	**6,162**	**242**	**417**	**828,325**

(*) Denotes less than one-half the unit of measure.
R = Revised data.
Notes: •All data are for 1 megawatt and greater. •Data are final; •See Technical Notes for North American Industry Classification System for these industry groups. •Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table A3. 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]
Utility				
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 A4
	fluidized bed[5]	31.00 x S	5.0	See Table A4
	spreader stoker	38.00 x S	11.0	See Table A4
	tangential	38.00 x S	15.0(14)	See Table A4
	all others	38.00 x S	22.0(31)	See Table A4
Subbituminous[4]	cyclone	35.00 x S	17.0	See Table A4
	fluidized bed[5]	31.00 x S	5.0	See Table A4
	spreader stoker	38.00 x S	8.8	See Table A4
	tangential	35.00 x S	8.4	See Table A4
	all others	35.00 x S	12.0(24)	See Table A4
Lignite[4]	cyclone	30.00 x S	15.00	See Table A4
	fluidized bed	10.00 x S	3.60	See Table A4
	front/opposed	30.00 x S	13.00	See Table A4
	spreader stoker	30.00 x S	5.80	See Table A4
	tangential	30.00 x S	7.10	See Table A4
	all others	30.00 x S	7.10(13)	See Table A4
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	32.00	173.72
	vertical	157.00 x S	47.00	173.72
	all others	157.00 x S	47.00	173.72
Distillate Oil[7]	all types	150.00 x S	24.00	161.27
Methanol	all types	See Table A5	See Table A5	138.15
Propane (liquid)	all types	86.5	19.00	139.04
Coal-Oil Mixture	all types	See Table A5	See Table A5	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	116.38
	all others	0.60	280.00	116.38
Blast Furnance Gas	all types	950.00	280.00	116.38
Nonutility				
Coal and Other Solid Fuels		**lbs per ton**	**lbs per ton**	**lbs per 10^6 Btu**
Anthracite Culm	all types	39.00 x S	1.80	See Table A4
Bituminous[4]	all types	38.00 x S	22.00	See Table A4
Bituminous Gob	all types	38.00 x S	22.00	See Table A4
Subituminous	all types	35.00 x S	12.00	See Table A4
Lignite[4]	all types	30.00 x S	12.00	See Table A4
Lignite Waste	all types	30.00 x S	12.00	See Table A4
Peat	all types	30.00 x S	12.00	0
Agricultural Waste	all types	See Table A5	See Table A5	0
Black Liquor	all types	See Table A5	See Table A5	0
Chemicals	all types	See Table A5	See Table A5	0
Closed Loop Biomass	all types	See Table A5	See Table A5	0
Internal	all types	See Table A5	See Table A5	0

See footnotes at end of table.

Table A3. 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	See Table A5	See Table A5	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[6]	all types	39.00 x S	14.00	225.13
Pitch	all types	See Table A5	See Table A5	See Table A5
Railroad Ties	all types	See Table A5	See Table A5	0
Red Liquor	all types	See Table A5	See Table A5	0
Sludge	all types	2.80	5.00	0
Sludge Waste	all types	2.80	5.00	0
Sludge Wood	all types	2.80	5.00	0
Spent Sulfite Liquor	all types	See Table A5	See Table A5	0
Straw	all types	See Table A5	See Table A5	0
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	See Table A5	See Table A5	See Table A5
Tires	all types	See Table A5	See Table A5	189.54
Waste Byproducts	all types	1.70	2.30	163.29
Waste Coal	all types	See Table A5	See Table A5	See Table A5
Wood/Wood Waste	all types	0.08	1.50	0
Petroleum and Other Liquid Fuels		**lbs per 10^3 gal**	**lbs per 10^3 gal**	**lbs per 10^6 Btu**
Heavy Oil[7]	all types	157.00 x S	47.00	173.72
Light Oil[7]	all types	142.00 x S	20.00	159.41
Diesel	all types	142.00 x S	20.00	161.27
Kerosene	all types	142.00 x S	20.00	159.41
Butane (liquid)	all types	0.09	21.00	143.20
Fish Oil	all types	See Table A5	See Table A5	0
Methanol	all types	See Table A5	See Table A5	138.15
Oil Waste	all types	147.00 x S	19.00	163.61
Propane (liquid)	all types	0.50	19.00	139.04
Sludge Oil	all types	147.00 x S	19.00	0
Tar Oil	all types	See Table A5	See Table A5	0
Waste Alcohol	all types	See Table A5	See Table A5	138.15
Natural Gas and Other Gaseous Fuels		**lbs per 10^6 cf**	**lbs per 10^6 cf**	**lbs per 10^6 Btu**
Natural Gas	all types	0.60	280.00	116.97
Butane (gas)	all types	0.60	21.00	143.20
Hydrogen	all types	See Table A5	550.00	0
Landfill Gas	all types	See Table A5	550.00	115.12
Methane	all types	See Table A5	550.00	115.11
Other Gas	all types	See Table A5	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 A6 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).

cf = Cubic Feet.
gal = Gallons.
lbs = Pounds.

Sources: •For sulfur dioxide and nitrogen oxide factors: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, Fifth Edition (through Supplement E), Research Triangle Park, North Carolina, July, 1999. •For carbon dioxide factors: Energy Information Administration, ''Emissions of Greenhouse Gases in the United States 1998,'' November 1999.

Table A4. 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	Utah	204.08
Bituminous	Virginia	206.23
Bituminous	Washington	203.62
Bituminous	West Virginia	207.10
Bituminous	Wyoming	206.48
Bituminous	Texas	204.39
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 A5. Sulfur Dioxide and Nitrogen Oxide Factors for Specific Fuels

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

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

2 If bottom type is unknown, dry bottom is assumed. Emission factors are for boilers with a gross heat rate of 100 million Btu per hour or greater. See Table A6 for nitrogen oxide reduction factors used to calculate controlled nitrogen emission estimates.

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

Table A6. Nitrogen Oxide Reduction Factors

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

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

Table A7. Unit-of-Measure Equivalents

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

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

Glossary

Acid Rain: Also called acid precipitation or acid deposition, acid rain is precipitation containing harmful amounts of nitric and sulfuric acids formed primarily by nitrogen oxides and sulfur oxides released into the atmosphere when fossil fuels are burned. It can be wet precipitation (rain, snow, or fog) or dry precipitation (absorbed gaseous and particulate matter, aerosol particles or dust). Acid rain has a pH below 5.6. Normal rain has a pH of about 5.6, which is slightly acidic. The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Actual Peak Reduction: The actual reduction in annual peak load (measured in kilowatts) achieved by consumers that participate in a utility DSM program. It reflects the changes in the demand for electricity resulting from a utility DSM program that is in effect at the same time the utility experiences its annual peak load, as opposed to the installed peak load reduction capability (i.e., Potential Peak Reduction). It should account for the regular cycling of energy efficient units during the period of annual peak load.

Allowance for Funds Used During Construction (AFUDC): A noncash item representing the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 ohm.

Annual Effects: The total effects in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused by all participants in the DSM programs that are in effect during a given year. It includes new and existing participants in existing programs (those implemented in prior years that are in place during the given year) and all participants in new programs (those implemented during the given year). The effects of new participants in existing programs and all participants in new programs should be based on their start-up dates (i.e., if participants enter a program in July, only the effects from July to December should be reported). If start-up dates are unknown and cannot be reasonably estimated, the effects can be annualized (i.e., assume the participants were initiated into the program on January 1 of the given year). The Annual Effects should consider the useful life of efficiency measures, by accounting for building demolition, equipment degradation and attrition.

Anthracite: A hard, black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. Comprises three groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free basis:

	Fixed Carbon Limits		Volatile Matter	
	GE	LT	GT	LE
Meta-Anthracite	98	-	-	2
Anthracite	92	98	2	8
Semianthracite	86	92	8	14

Appliances: Energy Efficiency program promotion of high efficiency appliances such as dishwashers, ranges, refrigerators, and freezers in the residential, commercial, and industrial sectors. Includes programs aimed at improving the efficiency of refrigeration equipment and electrical cooking equipment, including replacement. It also includes the promotion and identification of high efficiency appliances in retail stores using a labeling system different from the federally-mandated Energy Guide. Energy Efficiency program promotion of high efficiency cooling and heating appliances are included under Cooling System and Heating System, respectively.

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

Asset: An economic resource, tangible or intangible, which is expected to provide benefits to a business.

Available but not Needed Capability: Net capability of main generating units that are operable but not considered necessary to carry load, and cannot be connected to load within 30 minutes.

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

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Base Bill: A charge calculated through multiplication of the rate from the appropriate electric rate schedule by the level of consumption.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis.

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Bbl: The abbreviation for barrel.

Bcf: The abbreviation for 1 billion cubic feet.

Bituminous Coal: The most common coal. It is dense and black (often with well-defined bands of bright and dull material). Its moisture content usually is less than 20 percent. It is used for generating electricity, making coke, and space heating. Comprises five groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free (mmf) basis for fixed-carbon and volatile matter and a moist mmf basis for calorific value.

	Fixed Carbon Limits		Volatile Matter Limits		Calorific Value Limits Btu/lb	
	GE	LT	GT	LT	GE	LE
LV	78	86	14	22	-	-
MV	69	78	22	31	-	-
HVA	-	69	31	-	14000	-
HVB	-	-	-	-	13000	14000
HVC	-	-	-	-	10500	13000

LV = Low-volatile bituminous coal
MV = Medium-volatile bituminous coal
HVA = High-volatile A bituminous coal
HVB = High-volatile B bituminous coal
HVC = High-volatile C bituminous coal

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Capacity (Purchased): The amount of energy and capacity available for purchase from outside the system.

Capacity Charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity charge, sometimes called Demand Charge, is assessed on the amount of capacity being purchased.

Capital (Financial): The line items on the right side of a balance sheet, that include debt, preferred stock, and common equity. A net increase in assets must be financed by an increase in one or more forms of capital.

Census Divisions: The nine geographic divisions of the United States established by the Bureau of the Census, U.S. Department of Commerce, for the purpose of statistical analysis. The boundaries of Census divisions coincide with State boundaries. The Pacific Division is subdivided into the Pacific Contiguous and Pacific Noncontiguous areas.

Circuit: A conductor or a system of conductors through which electric current flows.

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alteration from lignite to anthracite. Lignite contains approximately 9 to 17 million Btu per ton. The contents of subbituminous and bituminous coal range from 16 to 24 million Btu per ton and from 19 to 30 million Btu per ton, respectively. Anthracite contains approximately 22 to 28 million Btu per ton.

Cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy," and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). (See the Code of Federal Regulations, Title 18, Part 292.)

Coincidental Demand: The sum of two or more demands that occur in the same time interval.

Coincidental Peak Load: The sum of two or more peak loads that occur in the same time interval.

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

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

Combined Cycle Unit: An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

Combined Pumped-Storage Plant: A pumped-storage hydroelectric power plant that uses both pumped water and natural streamflow to produce electricity.

Commercial: The commercial sector is generally defined as nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Commercial Operation: Commercial operation begins when control of the loading of the generator is turned over to the system dispatcher.

Connection: The physical connection (e.g. transmission lines, transformers, switch gear, etc.) between two electric systems permitting the transfer of electric energy in one or both directions.

Conservation and Other DSM: This Demand-Side Management category represents the amount of consumer load reduction at the time of system peak due to utility programs that reduce consumer load during many hours of the year. Examples include utility rebate and shared savings activities for the installation of energy efficient appliances, lighting and electrical machinery, and weatherization materials. In addition, this category includes all other Demand-Side Management activities, such as thermal storage, time-of-use rates, fuel substitution, measurement and evaluation, and any other utility-administered Demand-Side Management activity designed to reduce demand and/or electricity use.

Construction Work In Progress (CWIP): The balance shown on a utility's balance sheet for construction work not yet completed but in process. This balance line item may or may not be included in the rate base.

Consumption (Fuel): The amount of fuel used for gross generation, providing standby service, start-up and/or flame stabilization.

Contract Price: Price of fuels marketed on a contract basis covering a period of 1 or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Contract Receipts: Purchases based on a negotiated agreement that generally covers a period of 1 or more years.

Cooling System: Energy Efficiency program promotion aimed at improving the efficiency of the cooling delivery system, including replacement, in the residential, commercial, or industrial sectors.

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

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

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

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

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

Demand-Side Management Costs: The costs incurred by the utility to achieve the capacity and energy savings from the Demand-Side Management Program. Costs incurred by consumers or third parties are to be excluded. The costs are to be reported in nominal dollars in the year in which they are incurred, regardless of when the savings occur. Program costs include expensed items incurred to implement the program, incentive payments provided to consumers to install Demand-Side Management measures, and annual operation and maintenance expenses incurred during the year. Utility costs that are general, administrative, or not specific to a particular Demand-Side Management category are to be included in "other" costs.

Direct Load Control: Refers to program activities that can interrupt consumer load at the time of annual peak load by direct control of the utility system operator by interrupting power supply to individual appliances or equipment on consumer premises. This type of control usually involves residential consumers. Direct Load Control excludes Interruptible Load and Other Load Management effects. (Direct Load Control, as defined here, is synonymous with Direct Load Control Management reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report," with the exception that annual peak load effects are reported here and seasonal (i.e., summer and winter) peak load effects are reported on the OE-411.)

Direct Utility Cost: A utility cost that is identified with one of the DSM program categories (i.e. Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, Load Building).

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are Fuel Oils No. 1, No. 2, and No. 4; and Diesel Fuels No. 1, No. 2, and No. 4.

Distribution System: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Diversity Exchange: An exchange of capacity or energy, or both, between systems whose peak loads occur at different times.

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

Electric Rate Schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversite authority.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities.

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

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy Deliveries: Energy generated by one electric utility system and delivered to another system through one or more transmission lines.

Energy Effects: The changes in aggregate electricity use (measured in megawatthours) for customers that participate in a utility DSM program. Energy Effects should represent changes at the consumer meter (i.e. exclude transmission and distribution effects) and reflect only activities that are undertaken specifically in response to utility-administered programs, including those activities implemented by third parties under contract to the utility. To the extent possible, Energy Effects should exclude non-program related effects such as changes in energy usage attributable to nonparticipants, government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage, changes in consumer behavior that result in greater energy use after initiation in a DSM program, the natural operations of the marketplace, and weather and business-cycle adjustments.

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

Energy Receipts: Energy generated by one electric utility system and received by another system through one or more transmission lines.

Energy Source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Equity Capital: The sum of capital from retained earnings and the issuance of stocks.

Expenditure: The incurrence of a liability to obtain an asset or service.

Facility: An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting mechanical, chemical, and/or nuclear energy into electric energy are situated, or will be situated. A facility may contain more than one generator of either the same or different prime mover type. For a cogenerator, the facility includes the industrial or commercial process.

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

Federal Power Commission: The predecessor agency of the Federal Energy Regulatory Commission. The Federal Power Commission (FPC) was created by an Act of Congress under the Federal Water Power Act on June 10, 1920. It was charged originally with regulating the electric power and natural gas industries. The FPC was abolished on September 20, 1977, when the Department of Energy was created. The functions of the FPC were divided between the Department of Energy and the Federal Energy Regulatory Commission.

FERC: The Federal Energy Regulatory Commission.

Firm Gas: Gas sold on a continuous and generally long-term contract.

Firm Power: Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

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

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

Fly Ash: Particule matter from coal ash in which the particle diameter is less than 1×10^{-4} meter. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Forced Outage: The shutdown of a generating unit, transmission line or other facility, for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fossil-Fuel Plant: A plant using coal, petroleum, or gas as its source of energy.

Fuel: Any substance that can be burned to produce heat; also, materials that can be fissioned in a chain reaction to produce heat.

Fuel Expenses: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses include unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

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

Gas Turbine Plant: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand to drive the generator and are then used to run the compressor.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity): The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Net Generation: Gross generation less the electric energy consumed at the generating station for station use.

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

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical distribution system.

Gross Generation: The total amount of electric energy produced by a generating facility, as measured at the generator terminals.

Heating System: Energy Efficiency program promotion aimed at improving the efficiency of the heating delivery system, including replacement, in the residential, commercial, or industrial sectors.

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Incremental Effects: The annual effects in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused by new participants in existing DSM programs and all participants in new DSM programs during a given year. Reported Incremental Effects should be annualized to indicate the program effects that would have occurred had these participants been initiated into the program on January 1 of the given year. Incremental effects are not simply the Annual Effects of a given year minus the Annual Effects of the prior year, since these net effects would fail to account for program attrition, degradation, demolition, and participant dropouts.

Indirect Utility Cost: A utility cost that may not be meaningfully identified with any particular DSM program category. Indirect costs could be attributable to one of several accounting cost categories (i.e., Administrative, Marketing, Monitoring & Evaluation, Utility-Earned Incentives, Other). Accounting costs that are known DSM program costs should not be reported under Indirect Utility Cost, rather those costs should be reported as Direct Utility Costs under the appropriate DSM program category.

Industrial: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments Standard Industrial Classification (SIC) codes 01-39. The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Inoperable Capacity: Utility-owned or operated capacity that is totally or partially out of service for reasons such as: environmental restrictions, legal or regulatory restrictions, extensive modifications or repair, or capacity specified as being in a mothballed state.

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

Intermediate Load (Electric System): The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peak load, or the load over a specified time period.

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

Internal Demand: Peak hour integrated megawatt demand is defined as the sum of the demands of all customers that a system serves, including the demands of the organization providing the electric service, plus the losses incidental to that service. Total Internal Demand is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) is not included.

Internal Demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Internal Demand should not be reduced by Direct Control Load Management or Interruptible Demand.

Interruptible Demand: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the NERC Council or Reporting Party seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible Demand as reported here does not include Direct Control Load Management.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under certain circumstances, as specified in the service contract.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions. For example, loads that can be interrupted to fulfill planning or operation reserve requirements should be reported as Interruptible Load. Interruptible Load as defined here excludes Direct Load Control and Other Load Management. (Interruptible Load, as reported here, is synonymous with Interruptible Demand reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411, “Coordinated Regional Bulk Power Supply Program Report,” with the exception that annual peak load effects are reported on the Form EIA-861 and seasonal (i.e., summer and winter) peak load effects are reported on the OE-411).

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Leverage Ratio: A measure that indicates the financial ability to meet debt service requirements and increase the value of the investment to the stockholders. (i.e. the ratio of total debt to total assets).

Liability: An amount payable in dollars or by future services to be rendered.

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

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter (used almost exclusively for electric power generation). It is also referred to as brown coal. Comprises two groups classified according to the following ASTM Specification D388-84 for calorific values on a moist material-matter-free basis:

	Limits Btu/lb.	
	GE	LT
Lignite A	6300	8300
Lignite B	-	6300

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

Load Building: Refers to programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building should include programs that promote electric fuel substitution. Load Building effects should be reported as a negative number, shown with a minus sign.

Marketing Cost: Expenses directly associated with the preparation and implementation of the strategies designed to encourage participation in a DSM program. The category excludes general market and load research costs.

Monitoring & Evaluation Cost: Expenditures associated with the planning, collection, and analysis of data used to assess program operation and effects. It includes the activities such as load metering, customer surveys, new technology testing, and program evaluations that are intended to establish or improve the ability to monitor and evaluate the impacts of DSM programs, collectively or individually.

Maximum Demand: The greatest of all demands of the load that has occurred within a specified period of time.

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

MMcf: One million cubic feet.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Capability: The maximum load-carrying ability of the equipment, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. (Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations, and electrical use.)

Net Generation: Gross generation minus plant use from all electric utility owned plants. The energy required for pumping at a pumped-storage plant is regarded as plant use and must be deducted from the gross generation.

Net Internal Demand: Internal Demand less Direct Control Load Management and Interruptible Demand.

Net Summer Capability: The steady hourly output, which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of summer peak demand.

Net Winter Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of winter peak demand.

New Construction: Energy-efficiency program promotion to encourage the building of new homes, buildings, and plants to exceed standard government-mandated energy efficiency codes; it may include major renovations of existing facilities.

Noncoincidental Peak Load: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Non-Firm Power: Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of 10 regional reliability councils and one affiliate member and encompasses essentially all the power regional of the contiguous United States and Alaska, Canada, and Mexico. The NERC Regions are:

ASCC - The Alaska Systems Coordinating Council (affiliate NERC member)

ECAR - East Central Area Reliability Coordination Agreement

ERCOT - Electric Reliability Council of Texas

FRCC - Florida Reliability Coordinating Council

MAAC - Mid-Atlantic Area Council

MAIN - Mid-America Interconnected Network

MAPP - Mid-Continent Area Power Pool

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SPP - Southwest Power Pool

WSCC - Western Systems Coordinating Council

North American Industry Classification System (NAICS): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities. Formerly called the Standard Industrial Classification (SIC) prior to 1997.

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Off-Peak Gas: Gas that is to be delivered and taken on demand when demand is not at its peak.

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 volt produces a current of 1 ampere.

Operable Nuclear Unit: A nuclear unit is “operable” after it completes low-power testing and is granted authorization to operate at full power. This occurs when it receives its full power amendment to its operating license from the Nuclear Regulatory Commission.

Other Cost: A residual category to capture the Indirect Costs of DSM programs that cannot be meaningfully included in any of the other cost categories listed and defined herein. Included are costs such as those incurred in the research and development of DSM technologies.

Other DSM Programs: A residual category to capture the effects of DSM programs that cannot be meaningfully included in any of the program categories listed and defined herein. The energy effects attributable to this category should be the net effects of all the residual programs. Programs that promote consumer's substitution of electricity by other energy types should be included in Other DSM Programs. Also, self-generation should be included in Other DSM Programs to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories.

Other Incentives: Energy Efficiency programs that offer cash or noncash awards to electric energy efficiency deliverers, such as appliance and equipment dealers, building contractors, and architectural and engineering firms, that encourage consumer participation in a DSM program and adoption of recommended measures.

Other Load Management: Refers to programs other than Direct Load Control and Interruptible Load that limit or shift peak load from on-peak to off-peak time periods. It includes technologies that primarily shift all or part of a load from one time-of-day to another and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, and load limiting devices in energy management systems. This category also includes programs that aggressively promote time-of-use (TOU) rates and other innovative rates such as real time pricing. These rates are intended to reduce consumer bills and shift hours of operation of equipment from on-peak to off-peak periods through the application of time-differentiated rates.

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

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Peak Demand: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

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

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes fuel oil No. 2, No. 4, No. 5, No. 6; topped crude; Kerosene; and jet fuel.

Petroleum Coke: See Coke (Petroleum).

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Planned Capacity Resources: Utility- and IPP-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.

Planned Generator: A proposal by a company to install electric generating equipment at an existing or planned facility or site. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure for the facility.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Plant Use: The electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pumped-storage plants.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping at pumped-storage plants is, by definition, subtracted, and the energy production for these plants is then reported as a net figure.

Potential Peak Reduction: The potential annual peak load reduction (measured in kilowatts) that can be deployed from Direct Load Control, Interruptible Load, Other Load Management, and Other DSM Program activities. It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load.

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

Power Pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

Power Marketers: Power marketers are business entities engaged in buying and selling electricity, but do not own generating or transmission facilities. Power marketers, as opposed to Brokers, take ownership of the electricity and are involved in interstate trade. These entities file with FERC for status as a power marketer.

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).

Process Heating: Energy Efficiency program promotion of increased electric energy efficiency applications in industrial process heating.

Profit: The income remaining after all business expenses are paid.

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

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

Purchased Power Adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and it varies from a specified unit base amount.

Pure Pumped-Storage Hydroelectric Plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.) Part 292.

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

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Ratemaking Authority: A utility commission's legal authority to fix, modify, approve, or disapprove rates, as determined by the powers given the commission by a State or Federal legislature.

Receipts: Purchases of fuel.

Regulation: The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Residential: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. For the residential class, do not duplicate consumer accounts due to multiple metering for special services (water, heating, etc.). Apartment houses are also included.

Residual Fuel Oil: The topped crude of refinery operation, includes No. 5 and No. 6 fuel oils as defined in ASTM Specification D396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F-77); and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include imported crude oil burned as fuel.

Restricted-Universe Census: This is the complete enumeration of data from a specifically defined subset of entities including, for example, those that exceed a given level of sales or generator nameplate capacity.

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

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

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

Sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Sales for Resale: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

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

Small Power Producer (SPP): Under the Public Utility Regulatory Policies Act (PURPA), a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resource must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

Spinning Reserve: That reserve generating capacity running at a zero load and synchronized to the electric system.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low-fuel prices.

Stability: The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities (see North American Industry Classification System).

Standby Demand: The Demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Standby Demand is intended to be used infrequently by any one customer.

Standby Facility: A facility that supports a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service.

Standby Service: Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility if a schedule or an agreement authorizes the transaction. The service is not regularly used.

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

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

Subbituminous Coal: Subbituminous coal, or black lignite, is dull black and generally contains 20 to 30 percent moisture. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received and averages about 18 million Btu per ton. Subbituminous coal, mined in the western coal fields, is used for generating electricity and space heating.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Sulfur: One of the elements present in varying quantities in coal which contributes to environmental degradation when coal is burned. In terms of sulfur content by weight, coal is generally classified as low (less than or equal to 1 percent), medium (greater than 1 percent and less than or equal to 3 percent), and high (greater than 3 percent). Sulfur content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Total DSM Cost: Refers to the sum of total utility cost and nonutility cost.

Total DSM Programs: Refers to the total net effects of all the utility's DSM programs. For the purpose of this survey, it is the sum of the effects for Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building. Net growth in energy or load effects should be reported as a negative number, shown with a minus sign.

Total Nonutility Cost: Refers to total cash expenditures incurred by consumers and trade allies that are associated with participation in a DSM program, but that are not reimbursed by the utility. The nonutility expenditures should include only those additional costs necessary to purchase or install an efficient measure relative to a less efficient one. Costs are to be reported in nominal dollars in the year in which they are incurred, regardless of when the actual effects occur. To the extent possible, provide the best estimate of nonutility costs if actual costs are unavailable.

Total Utility Cost: Refers to the sum of the total Direct and Indirect Utility Costs for the year. Utility costs should reflect the total cash expenditures for the year, reported in nominal dollars, that flowed out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occur.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

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

Uniform System of Accounts: Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Useful Thermal Output: The thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation.

Utility-Earned Incentives: Costs in the form of incentives paid to the utility for achievement in consumer participation in DSM programs. These financial incentives are intended to influence the utility's consideration of DSM as a resource option by addressing cost recovery, lost revenue, and profitability.

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Water Heating: Energy Efficiency program promotion to increase efficiency in water heating, including low-flow shower heads and water heater insulation wraps. Could be applicable to residential, commercial, or industrial consumer sectors.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.