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# Electric Power Annual 1995
# Volume II

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**Energy Information Administration**
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# Contacts

Questions regarding this report may be directed to:
Energy Information Administration, EI-52
Coal and Electric Data and Renewables Division
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-0650

Questions of a general nature should be directed to:
Howard Walton (202/426-1156)
Internet E-Mail: hwalton@eia.doe.gov
Director, Coal and Electric Data
and Renewables Division

Contributions to this report were provided by the following employees of the Coal and Electric Data and Renewables Division (fax number 202/426-1308):

*Volume II Publication Coordinator:*

Linda Bromley (202/426-1164),
Internet E-Mail: lbromley@eia.doe.gov;

*The U.S. Electric Power Industry at a Glance:*

Larry Prete (202/426-1161),
Channele Donald (202/426-1270);

*U.S. Electric Utility Retail Sales and Revenue:*

Linda Bromley (202/426-1164),
Channele Donald (202/426-1270);

*U.S. Electric Utility Financial Statistics:*

Jerome A. Sanderson (202/426-1162) Investor,
Thomas S. Williams (202/426-1267) Investor,
Charlene Harris-Russell (202/426-1163) Public;

*U.S. Electric Utility Environmental Statistics:*

John G. Colligan (202/426-1174);

*U.S. Electric Power Transactions:*

John Makens (202/426-1165);

*U.S. Electric Utility Demand-Side Management:*

Linda Bromley (202/426-1164),
Channele Donald (202/426-1270);

*U.S. Nonutility Power Producers:*

Betty Williams (202/426-1269).

# Quality

The Energy Information Administration is committed to quality products and quality service. To ensure that this report meets the highest standards for quality, please forward your comments or suggestions about this publication to Linda Bromley at (202/426-1164) or Internet E-Mail: lbromley@eia.doe.gov.

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

# Preface

## Two-Volume Approach to the Electric Power Annual

The *Electric Power Annual* is published in two volumes, first released in 1995. Volume I, released July 1996, focuses on U.S. electric utility data on net generation, fossil fuel consumption, stocks, receipts, and cost. Volume I also contains preliminary data on generating unit capability and planned additions, as well as estimated retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold. Also included in Volume I is information on net generation and associated generating capability from renewable energy sources and the estimates for national-level nonutility data.

Volume II presents annual summary statistics for the electric power industry, including information on both electric utilities and nonutility power producers. Included are the preliminary data for electric utility retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold and for electric utility financial statistics, environmental statistics, power transactions, and demand-side management. Final data for U.S. nonutility power producers on installed capacity and gross generation, as well as supply and disposition information, are provided in Volume II.

The *Electric Power Annual 1995, 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 Coal and Electric Data and Renewables 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 decisionmaking 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 analysts, researchers, statisticians, and other professionals with regulatory, policy, and program responsibilities for Federal, State, and local governments. The Congress and other legislative bodies are also interested in general trends related to electricity at State and national levels. Data in this report can be used in analytic studies to evaluate new legislation. Public service commissions and other special government groups share an interest in State-level statistics.

In Volume II, the section titled "The U.S. Electric Power Industry at a Glance" highlights key statistics for the year. Subsequent sections present data on electric utility retail sales and revenue, electric utility financial statistics, electric utility environmental statistics, electric power transactions, electric utility demand-side management, and nonutility power producers. Each section contains related text and tables and refers the reader to the appropriate publication that contains more detailed data on the subject matter. Monetary values in this publication are expressed in nominal terms.

Data published in the *Electric Power Annual, Volume II* are compiled from six forms filed annually by electric utilities and one form filed annually by nonutility power producers. These forms are described in detail in the "Technical Notes."

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# The U.S. Electric Power Industry at a Glance

The first section of this chapter provides a profile of the electric power industry in the United States. The second section summarizes pertinent statistics on various aspects of the U.S. electric power industry for the year and includes a graphic presentation.

## Industry Profile

The U.S. electric power industry is composed of traditional electric utilities; nontraditional electricity-producing companies, also known as nonutilities; and, due to restructuring of the industry, new industry participants such as power marketers and brokers. The traditional electric utilities, investor-owned, publicly owned, cooperative, and Federal utilities, are generally companies that provide generation, transmission, distribution, and/or energy services for all customers in a designated service territory. In addition to the traditional electric utilities, there are new nontraditional entities in the electric power industry such as nonutility power producers, power marketers, and power brokers.[1] The electric power industry in the United States historically has been a highly regulated, monopolistic industry. However, with passage of Federal legislation in recent years, the industry is in the process of becoming less regulated and more competitive. Significant changes are taking place as the industry transitions from the traditional monopolistic structure to a competitive structure. Continuing deregulation of the industry at both the Federal and State levels has the potential to increase competition and change the nature of the way electricity is priced, traded, and marketed in the United States.

### *Traditional Electric Utilities*

*Investor-Owned Electric Utilities.* Investor-owned electric utilities currently account for more than 75 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 have the objective of producing a return for their investors. They either distribute their profits to stockholders as dividends or reinvest these profits. They 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.

[1] In this report, the following definitions are used to distinguish between the traditional electric utility and nonutility power producer: an electric utility is 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. A legal entity selling electric energy produced at a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA) is not an electric utility, but is a nonutility power producer. A nonutility power producer is any person, corporation, municipality, State political subdivision or agency, Federal agency, or other legal entity that either: (1) produces electric energy as a QF under PURPA, (2) produces electric energy but is primarily engaged in business activities other than the sale of electric energy, such as agriculture, mining, manufacturing, transportation, or education, and generally generates electricity for its own use and sells excess power to the host utility, or (3) produces and sells power wholesale at nonregulated rates and does not have a franchised service territory.

*Publicly Owned Electric Utilities.* Publicly owned electric utilities in the United States are nonprofit local 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 still 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, 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. 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 operates and distributes power from its own projects; also, it markets both the wholesale and retail electricity. On November 28, 1995, the President signed a bill authorizing the sale of the Alaska Power Administration's projects. Final transfer of title to the State of Alaska and three utilities is anticipated in November, 1997.

## The Changing Industry

The electric power industry, spurred by the passage of several bills including the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPACT), is evolving from a highly regulated, monopolistic industry to a less regulated, competitive industry. This evolving industry includes new participants such as exempt wholesale generators (EWG's) and power marketers.

PURPA facilitated the emergence of a group of nonutility electricity-producing companies called qualifying facilities (QF). Qualifying facilities receive certain benefits under PURPA. Under PURPA for small power producers and cogenerators to receive status as a QF, the facility must produce electric and another form of useful thermal energy through the sequential use of energy, and must meet certain ownership, operating, and efficiency requirements established by the Federal Energy Regulatory Commission (FERC). The facility must generate electricity with at least 75 percent total energy input from biomass, renewable resources, or geothermal energy as the primary source. Cogenerators are generating facilities that produce electricity and another form of useful thermal energy, usually heat or steam, for industrial processes or heating or cooling purposes. Qualifying facilities receive certain benefits under PURPA.[2]

Also considered nonutilities in the United States are independent power producers. These entities are wholesale electricity producers and are unaffiliated with the franchised utilities in the area in which they sell power. Unlike traditional electric utilities, IPP's do not possess transmission facilities and do not have retail sales of power. By definition, a facility that has QF status under PURPA is not an IPP.

The Energy Policy Act of 1992 (EPACT) modified the Public Utility Holding Company Act (PUCHA) and created another class of nonutilities, exempt wholesale generators (EWG).[3] EPACT exempted EWG's 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.

The EPACT also amended the Federal Power Act (FPA) such that any electric utility can apply to the FERC for an order requiring another electric utility to provide transmission services (wheeling). Prior to EPACT, the FERC could not mandate an electric utility provide wheeling services for wholesale electric trade. This change in the law permits owners of electric generating equipment to sell wholesale power (sales for resale) to noncontiguous utilities. More recently, the Federal Energy Regulatory Commission (FERC) issued two final orders, 888 and 889, implementing EPACT's provisions for open access to transmission lines. Order 888 addresses equal access to the transmission grid for all wholesale buyers and sellers, transmission pricing, and the recovery of stranded costs. Stranded costs are the investments made by utilities under the regulated environment that may not be recoverable in market-based rates in a competitive environment. Order 889 requires jurisdictional utilities that own or operate transmission facilities to establish electronic systems to share information about their available transmission capacities. In response to these rulemakings, utilities are proposing to form Independent System Operators (ISO) to operate the transmission grid, form regional transmission groups, and develop open access same-time information systems (OASIS) to inform all competitors of the available capacity on their lines.

The provision for open transmission access in EPACT has also facilitated the role of new participants in the electric power industry, power marketers and power brokers. Power marketers are entities engaged in buying and selling wholesale electricity and fall under the jurisdiction of the FERC, since they take ownership of electricity and are engaged in interstate trade. Power brokers, who do not take ownership of electricity, are not regulated by the FERC. A growing number of power marketers have filed with the FERC and had their rates approved. These power marketers generally do not possess generation or transmission facilities or sell power to retail customers. However, with the continuing deregulation of the industry, and the existance of pilot programs for retail choice that some States are initiating, power marketers are beginning to enter retail electricity markets. Due to deregulation, power marketers are increasing their presence in the electric power industry.

Additionally, State legislatures and the Congress are considering legislation that will allow competition in retail sales of electric power. At least two States, Rhode Island and California, have passed bills that will allow end-use customers in their States to begin choosing among competitive generation suppliers by 1998. Transmission and distribution will remain regulated functions with rules to assure open access to lines for all competitors. Continuing deregulation at both Federal and State levels is transforming the historically monopolistic electric power industry into a competitive industry that will eventually increase competition in the generation and service components of the electric power industry, and change the nature of the way electricity is priced, traded, and marketed in the United States.

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

[3] EWG's are not considered electric utilities under PUHCA; they are restricted to selling wholesale power to electric utilities and municipalities. For this report, EWG's are classified as nonutilities. However, EWG's were considered to be electric utilities under the Federal Power Act.

# A Review of 1995

A graphic presentation (Figures 1 through 10) on the U.S. electric utility industry includes: retail sales of electricity, associated revenue, and average revenue per kilowatthour sold by class of ownership; number of ultimate consumers served and number of electric utilities by class of ownership; sales for resale and associated revenue by class of ownership; net sales and average revenue per kilowatthour by sector; and nonutility installed and planned capacity. These data are collected and compiled from various sources, as indicated in the Preface.

## *U.S. Electric Utility Statistics*

*Retail Sales and Revenue.* In 1995, sales of electricity to ultimate consumers increased to 3,013 billion kilowatthours, approximately 2.7 percent more than the 2,935 billion kilowatthours recorded in 1994. Revenue from retail sales increased from $203 billion in 1994 to $208 billion in 1995, a 2.5-percent increase (Table 1). Average revenue per kilowatthour decreased slightly, from 6.91 cents in 1994 to 6.89 cents in 1995.

Residential sales increased by 3.4 percent to 1,043 billion kilowatthours; commercial by 5.2 percent to 863 billion kilowatthours and industrial by 0.5 percent to 1,013 billion kilowatthours; other decreased 2.5 percent to 95 billion kilowatthours. Revenue from residential consumers increased 3.6 percent to $88 billion and commercial increased 4.7 percent to $66 billion; industrial revenue decreased 1.9 percent to $47.2 billion; and other remained steady at $7 billion. The decrease in industrial revenue and increase in sales is indicative of the trend of falling industrial rates. This can be attributed to utilities shifting consumers between the industrial and commercial sectors and a willingness to negotiate with industrial consumers for lower rates in response to rising competition in the electric power industry.

Average revenue per kilowatthour was 8.40 cents in the residential sector, 7.69 cents in the commercial sector, 4.66 cents in the industrial sector, and 6.88 in the other sector. Average revenue for the residential sector is generally higher than for the other sectors, due in part to the relatively small consumption level per consumer and the relatively low load factor. The load factor is average load expressed as a percentage of the peak load. Generally, a consumer whose average load is low relative to its maximum demand is more costly to serve than a consumer whose load factor is high. Residential consumers typically have a lower load factor than industrial consumers.

Among the ownership classes, investor-owned electric utilities account for more than 75 percent of all retail sales and revenue, with publicly owned and cooperative electric utilities providing the remainder. Federal electric utilities are primarily wholesalers of electricity. Sales to ultimate consumers increased in 1995 for electric utilities in all ownership classes: investor-owned, by 2.5 percent to 2,292 billion kilowatthours; publicly owned, by 2.4 percent to 432 billion kilowatthours; cooperatives, by 5.0 percent to 240 billion kilowatthours; and Federal, by 6.0 percent to 50 billion kilowatthours. Revenue likewise increased for all ownership classes: investor-owned, by 2.6 percent to $164 billion; publicly owned, by 1.1 percent to $26 billion; cooperatives, by 3.7 percent to $17 billion; and Federal, by 3.2 percent to $1 billion.

Average revenue per kilowatthour decreased for all ownership classes except investor-owned electric utilities that increased slightly in 1995 to 7.15 cents from 7.14 cents in 1994. For publicly owned electric utilities, the average revenue per kilowatthour decreased from 6.10 cents to 6.02 cents; cooperatives from 7.01 cents to 6.92 cents; and for Federal electric utilities from 2.76 cents in 1994 to 2.69 cents in 1995.

Federal electric utilities generally have the lowest average revenue per kilowatthour because they have access to relatively low-cost financing and generally utilize facilities that are relatively inexpensive to operate. 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, they generally serve sparsely populated areas and provide service to a higher percentage of rural residential customers than other classes of electric utilities. As a consequence, cooperative electric utilities generally have a higher average revenue per kilowatthour than do publicly owned electric utilities.

*Financial.* In 1995, the major investor-owned electric utilities had electric utility operating revenues of $183.7 billion. Electric operating expenses ($150.6 billion) increased by only 1.3 percent resulting in an increase of $2.4 billion (7.9 percent) in operating income. Electric generating and maintenance expenses excluding fuel went down $1.5 billion in 1995 from 1994. Net income ($22.0 billion) showed an increase of 10.9 percent from 1994. Earnings available to common stock increased by $2.2 billion or 12.2 percent. Earnings available per average common share were $3.04, continuing its steady increase.

In 1995, investment in the major investor-owned segment of the industry was $578.9 billion, an increase of $4.4 billion from 1994. Electric utility construction work in progress (CWIP) was $13.5 billion, a decrease of 21.1 percent from 1994 and a decrease of 34.5 percent from 1992. The total asset turnover ratio (operating revenues divided by total assets) remained about the same at 0.35. Total capitalization of $365.8 billion increased by $1.0 billion from that in 1994. The percent of long-term debt to total capitalization stood at 47.5, down from the ratio of 48.1 in the previous year.

In 1995, the major publicly owned generator electric utilities had electric utility operating revenue of $20.8 down by 11.9 percent. Generator electric utility operating expenses decreased by 11.6 percent, resulting in an increase in net income ($0.1 billion) of 14.9 percent. Total assets for publicly owned generator electric utilities decreased 14.8 percent to $99.5 billion. The Electric Utility Plant per Dollar of Revenue ratio was 4.0 in 1995.

In 1995, the major publicly owned nongenerator electric utilities had electric utility operating revenue of $8.4 billion, a 4.4-percent growth over 1995. Nongenerator electric utility operating expenses increased by 4.4 percent to end the year at $7.9 billion. Net income for nongenerators remained $0.4 billion. Total assets for nongenerator electric utilities increased by 14.4 percent to end the year at $11.8 billion. The Electric Utility Plant per Dollar of Revenue ratio was 1.2 in 1995.

*Environmental.* In 1995, air emissions from electric utility operated fossil-fueled steam electric plants were estimated at less than 12 million tons of sulfur dioxide ($SO_2$); 7 million tons of nitrogen oxides ($NO_x$); and 1,968 million tons of carbon dioxide ($CO_2$). There was a decrease in the $SO_2$, $NO_x$, and $CO_2$ emissions for 1995 from the previous year. The most significant was for $SO_2$ emissions, a decrease of more than 19 percent. This decrease is mostly due to power plants that must comply with restrictions on $SO_2$ emissions specified in Phase I of the Clean Air Act Amendments of 1990 (CAAA-90), which became effective in January 1995. The electric utilities owning the 110 power plants targeted to reduce $SO_2$ emissions (under Phase I provisions) selected from several of the strategies available to them to meet those goals. The strategy elected by many of the utilities was relying on the consumption of lower sulfur coal to meet the requirements. Some utilities added pollution abatement equipment to boilers, retired or reworked boilers, or used a combination of strategies including earned or purchased allowances to meet the emissions standards.

Flue gas desulfurizations (FGD) sometimes referred to as scrubbers use chemicals such as lime to remove sulfur oxides from the combustion gases of boilers before the gases are discharged into the atmosphere. In 1995, there were 177 generators connected to scrubbers at U.S. power plants, compared with 168 in 1994 and 137 in 1985, a 5- and 29-percent increase, respectively. The average sulfur content of coal delivered to all U.S. electric utility plants decreased from 1.17 percent by weight in 1994 to 1.08 percent by weight in 1995.

*Power Transactions.* On a national level, wholesale power receipts (purchased power plus exchanges received and wheeling received) increased to 2,020 billion kilowatthours in 1995 from 1,927 billion kilowatthours in 1994. Each year, however, as total trade increased, the exchange-received components decreased. This pattern reflects a structural change in the wholesale trade sector of the electric power industry. From a national total of 241 billion kilowatthours in 1991 to 159 billion kilowatthours in 1995, exchanges received fell nearly 80 billion kilowatthours. The electric power industry has shifted away from in-kind exchanges of electricity to purchased power transactions as increased price competition has become apparent among traditional electric utilities.[4]

In 1995, the noncoincidental peak load at electric utilities in the contiguous U.S. showed an increase of 6 percent growth from the prior year to 621 million kilowatts for the summer period. The winter peak load period reversed its decline from the prior year and increased 26 million kilowatts, to 545 million kilowatts for the contiguous U.S.. By the year 2000, the contiguous U.S. winter and summer peak loads are expected to grow to 585 and 661 million kilowatts, respectively.

In 1995, United States imports of electricity dropped to 47 billion kilowatthours of electricity from Canada and Mexico and exports increased to over 9 billion kilowatthours. More than 23 billion kilowatthours entered the United States at the northeastern border, while over 7 billion kilowatthours entered through Washington State for consumption in the West. More than three-fourths of the the electricity exported was transmitted from the Western Systems Coordinating Council (WSCC).

[4] In 1990, the Federal Energy Regulatory Commission (FERC) changed its treatment of one wholesale trade account. The definition for Summary of Interchange was clarified and the term replaced with the terms, Exchanges Received and Exchanges Delivered. The FERC reemphasized "in-kind exchanges of electricity" as the meaning of the term. When this clarification of the definition was implemented, the quantity of electricity reported traded in this category dropped nearly in half, from 427 billion kilowatthours in 1990 to 241 billion kilowatthours in 1991.

*Demand-Side Management.* Most States are actively considering proposals for restructuring the electric power industry, including options for deregulating the the generation segment of the industry and providing retail access. A few States, such as California, have enacted statutes and/or adopted policies that will create a competitive retail access market. Such changes are affecting utility demand-side management (DSM) activities and could significantly change the financing, structure, and delivery of end use energy services.

Traditionally, utility DSM programs have been developed through an integrated resource planning process which compared the cost of DSM programs to the cost of other resources and are approved by State Public Utilities Commissions. In a competitive market, regulated utilities may not retain their obligation to provide generation services and regulatory oversight of their DSM programs. Additionally, competition is creating pressure for utilities to cut costs. In some instances, this has resulted in a reduction in planned DSM expenditures and a shift away from customer rebate programs. Further, to the extent utility generation revenues ultimately may be based on competitive market prices, a conflict could emerge between the interests of generation owning utilities in higher generation prices and the effects of some DSM programs to reduce demand and possibly to help hold down competitive prices for generation. These factors could contribute to slower growth in energy savings from DSM programs.

New retailing activities are emerging as competition grows in the electric power industry. These activities include increased utility attention to marketing and those of new brokers and energy service companies. These new energy retailers can be expected to offer customers packages of services that include electricity (and in some cases natural gas), financial services to hedge price uncertainty, and expanded energy management services designed to allow consumers to adjust their energy usage to changing electricity prices. Demand-side services will be competitively marketed as a means of helping consumers manage their energy bills. These services may include automated energy management linked to a communications system that provides consumers and their energy management systems access to changing hourly electricity prices.

Regulators and legislators in some States are likely to set aside funds collected from all consumers connected to the distribution system to support energy efficiency programs. The California restructuring legislation has used this approach to require utilities to purchase energy efficiency savings under standard offers.

Utilities in the Pacific Northwest and New England have formed consortiums to support energy efficiency market transformation, programs that attempt to create lasting changes in markets for energy efficient products. Such efforts may represent a more economical way to achieve long-term energy savings.

Also, 1995 incremental savings from energy efficiency programs nearly matched the level of incremental savings achieved in 1994. This suggests that efficiency programs are continuing to play a significant role in the Nation's resource mix, even as it changes to reflect the development of a more competitive electric power industry.

In 1995, 1,053 of the 3,199 electric utilities in the United States reported having DSM programs, an increase of 2.2 percent over 1994. Of these 1,053 utilities, 470 are classified as small and 583 as large.[5] The 1,053 utilities account for 85 percent of the total retail sales of electricity in the United States.

Energy savings for the 583 large electric utilities increased to 57,421 million kilowatthours, 4,938 million kilowatthours over 1994. These energy savings represent 1.9 percent of annual electric sales of 3,013,411 million kilowatthours, to ultimate consumers in 1995.

Actual peak load reductions for large utilities increased 18.2 percent from 25,001 megawatts in 1994 to 29,561 megawatts in 1995. These actual peak load reductions are approximately 4 percent of total peak load in the United States. Potential peak load reductions increased 9.6 percent from 42,917 megawatts in 1994 to 47,029 megawatts in 1995.

DSM costs decreased from $2.71 billion in 1994 to $2.42 billion.[6] This is the second consecutive year that DSM costs have decreased from a high of $2.74 billion in 1993.

Incremental effects are those caused by new programs and new participants in existing programs for the current reporting year. For 1995, incremental energy savings for large utilities were 8,242 million kilowatthours, incremental actual peak load reductions were 4,636 megawatts, and incremental potential peak load reductions were 6,539 megawatts.

[5] Large utilities are those reporting sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours. These utilities are required to report incremental and annual peak load reductions and energy savings for the reporting year (1995), annual peak load reduction and energy savings for the first and fifth forecast years (1996 and 2000), and itemized direct and indirect utility costs for all three years (1995, 1996, and 2000). Small utilities with sales to ultimate consumers and sales for resale of less than 120,000 megawatthours are only required to report incremental energy savings and peak load reduction, and total utility, total nonutility, and total DSM costs for the reporting year and for the first and fifth forecast years.

[6] It is tempting, but misleading, to compare DSM costs to supply-side investments on an unadjusted cost-per-kilowatthours or cost-per-kilowatt basis. The calculation of appropriate measures for economic comparisons of DSM and supply-side investments requires that consideration of the life-cycle cost of the options being compared be addressed on an integrated basis (i.e., the interaction of the change in end-use patterns with the production function of the utility must be considered over the expected life of the various options being compared). In addition, the rate impacts of each alternative must be compared because alternative DSM/supply-side combinations may result in differing patterns of revenue requirements over time. The data presented are not sufficient to allow for such comparison.

## U.S. Nonutility Power Producer Statistics

*Generation.* In 1995, U.S. nonutility power producers with facilities having an installed capacity of 1 megawatt or more generated 374 billion kilowatthours of electricity. U.S. nonutility power producers received 90 billion kilowatthours from and delivered 232 billion kilowatthours to electric utilities and other end users. Nonutility power producers delivered approximately 61.9 percent of their gross generation to electric utilities and other end users and used 232 billion kilowatthours for power plant operation and for industrial processes. The highest level of nonutility production of electricity occurred in California and Texas, with 63 and 55 billion kilowatthours, respectively.

Gross generation for nonutility power producers with an installed capacity of 1 megawatt or more was 5.5 percent higher in 1995 than a year earlier. Slightly more than half of the generation by nonutility power producers was gas-fired, with generation from coal accounting for 15.4 percent of the total. Of the total nonutility generation, 315 billion kilowatthours were from qualifying facilities, more than five times the quantity from nonqualifying facilities. (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 West South Central Census Division, followed by the Pacific Census Division. The manufacturing sector dominates electricity generation and is concentrated in the West South Central and Middle Atlantic Census Divisions, 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 power producers with an installed capacity of 1 megawatt or more was 70,254 megawatts at the end of 1995. The installed capacity for facilities of 1 megawatt or more increased by 2.6 percent from 1994. Nonutility capacity in 1995 was equivalent to 9.3 percent of the traditional U.S. electric utility installed capacity.[7]

Of all energy sources, gas accounted for the largest amount (29,272 megawatts) of nonutility capacity. The West South Central Census Division accounted for 37.3 percent of that gas-fired capacity. The second largest share of nonutility capacity was provided by petroleum, followed by coal. The largest volume of petroleum capacity (3,755 megawatts) was located in the South Atlantic Census Division. Cogeneration accounts for 78.2 percent of nonutility capacity (68.4 percent qualifying facility capacity and 9.8 percent nonqualifying facility capacity). Small power producers and independent power producers account for 13.7 and 7.9 percent, respectively, of nonutility capacity.

The greatest number (539) of nonutility generating facilities was in the Pacific Census Division, and most of the capacity (13,891 megawatts) was in the West South Central Census Division. 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. In the West South Central Census Division, Texas dominated mainly because of the large potential for cogeneration in the petroleum refining industry, where thermal and electric load requirements are co-located.

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 constructors (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 contract 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. Nonutilities plan approximately 9 gigawatts of capacity additions; 5 gigawatts through 1998 with 11 gigawatts (generator nameplate capacity) planned for the same period by electric utilities. Electric utilities have planned 48 gigawatts (generator nameplate capacity) in capacity additions for the 10-year period, 1996 through 2005. Of the nonutility planned capacity, 20.0 percent is petroleum and/or gas-fired. Coal-fired capacity represents 11.7 percent of the total planned nonutility additions.

*Consumption.* In 1995, consumption by nonutilities of 1 megawatt or more included 2,311 billion cubic feet of natural gas, 48 million short tons of coal, and 39 million barrels of petroleum. Compared to 1994, consumption decreased 3.4 percent for petroleum, 8.4 percent for coal, and increased 7.5 percent for gas. Natural gas was the fuel most used by nonutilities.

*Emissions.* In 1995, estimated air emissions from nonutility facilities of 1 megawatt or more were 1,217 thousand short tons in $SO_2$, 1,440 thousand short tons of $NO_x$, and 556,324 thousand short tons of $CO_2$. This

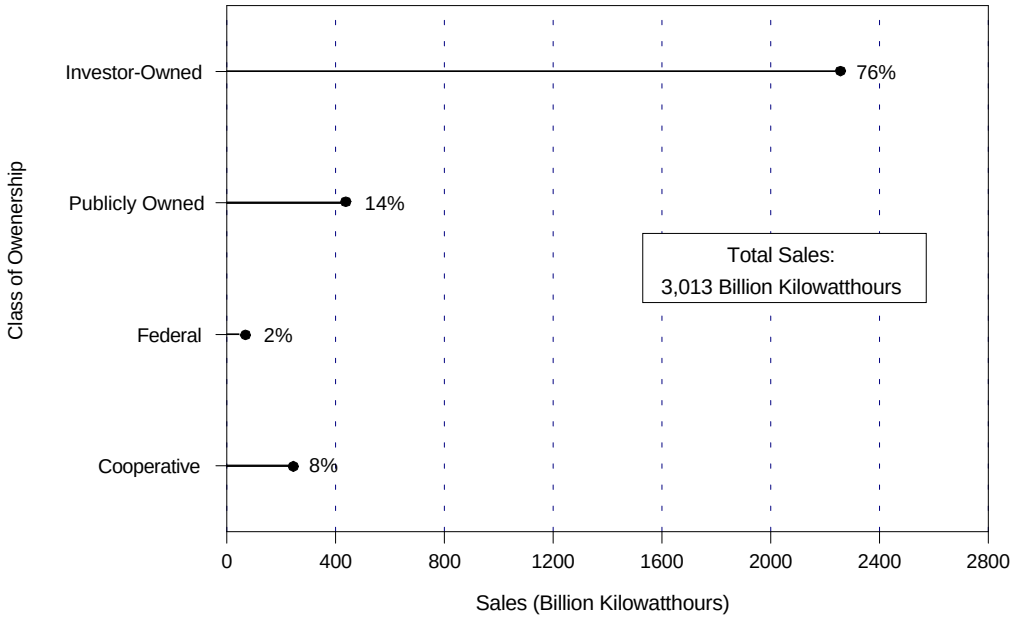
[7] Energy Information Administration, *Inventory of Power Plants in the United States 1993,* DOE/EIA-0095(93).

is a 14.5 percent decrease of $SO_2$ emissions from the previous year. The decrease of $SO_2$ emissions was due to lower sulfur content of fuel consumed from the previous year.

## Renewable Energy Resources

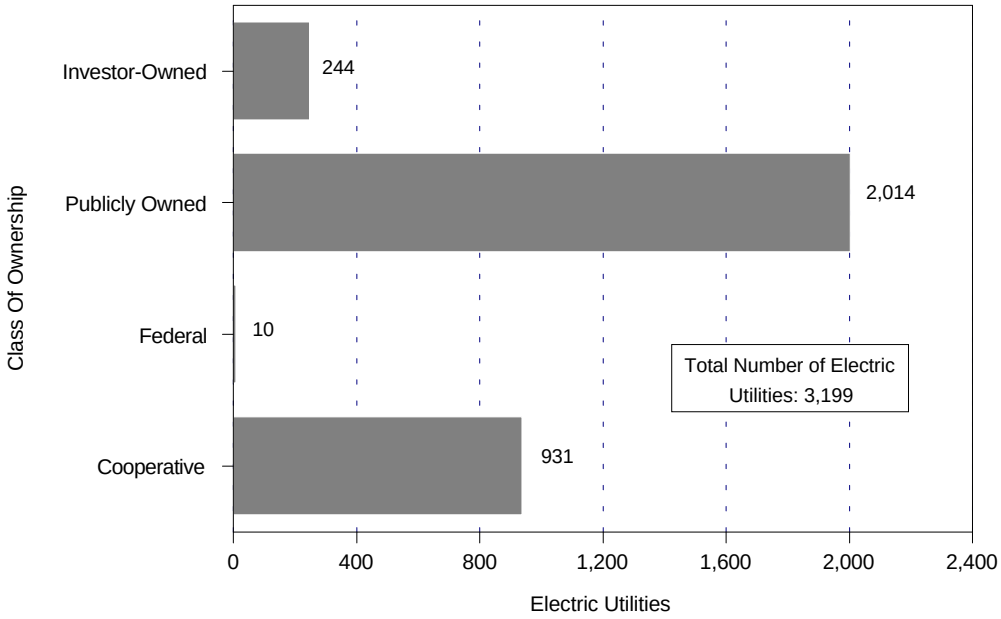
Section 171 of Public Law 102-486, the Energy Policy Act of 1992, requires the Administrator of the Energy Information Administration to annually collect and publish the results of a survey of electricity production from domestic renewable energy resources. This requirement includes reporting data on electricity production (in kilowatthours) and total installed capacity. Renewable energy resources in Table 1, "Electric Power Industry Summary Statistics for the United States, 1994 and 1995," are reported in detail in the *Renewable Energy Annual, 1995*.

**Figure 1. U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1995**



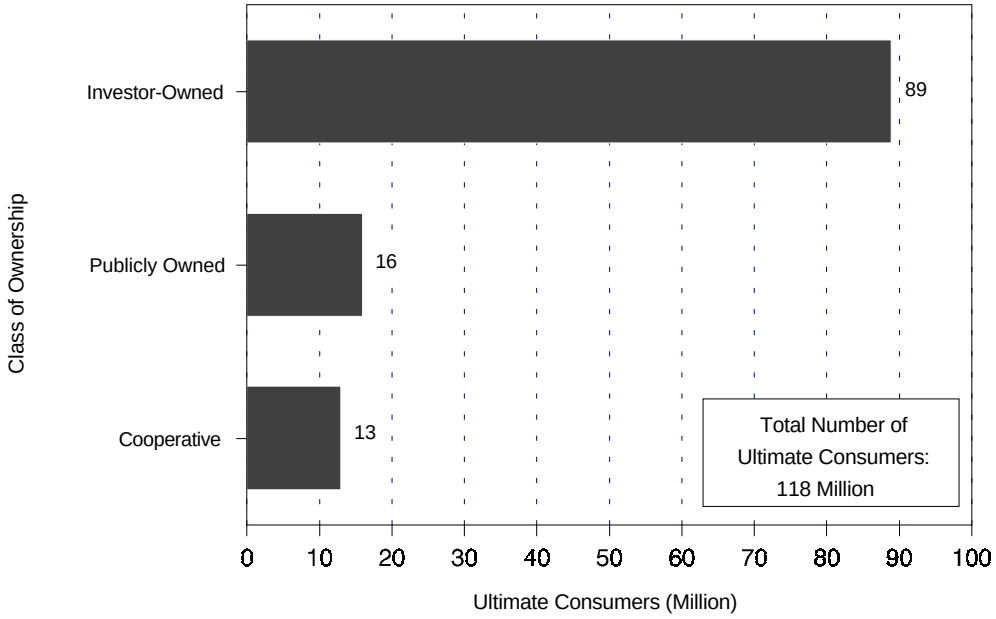

Notes: ●Data are preliminary. ●Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

**Figure 2. Number of U.S. Electric Utilities by Class of Ownership, 1995**



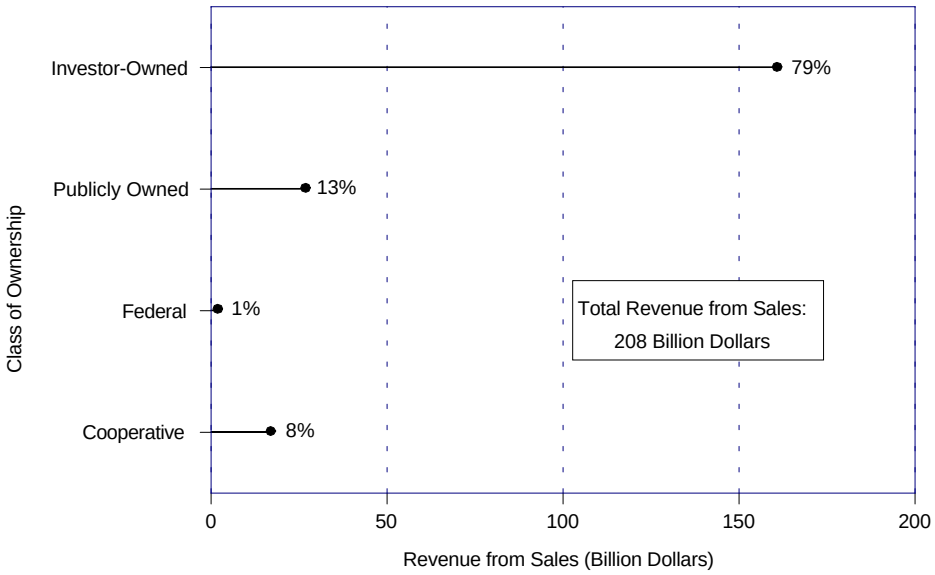

Notes: ●Data are preliminary. ●Power Marketers are not shown this year.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

**Figure 3. Number of Ultimate Consumers Served by U.S. Electric Utilities by Class of Ownership, 1995**



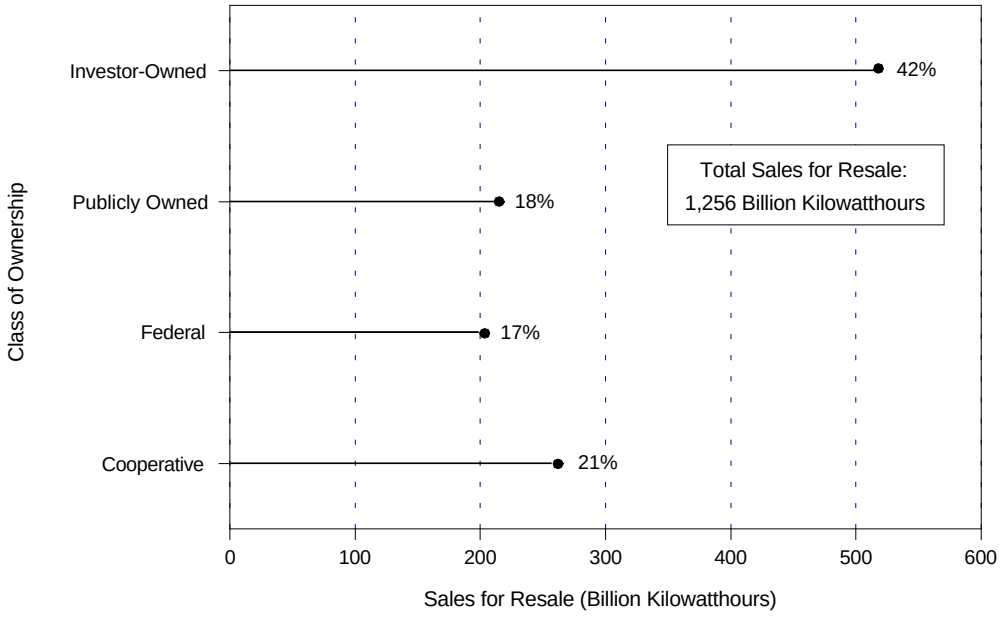

Notes: ●Data are preliminary. ●The number of ultimate consumers served by Federal electric utilities not shown because it is less than 1 million. ●The number of ultimate consumers is an average of the number of consumers at the close of each month. ●Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

**Figure 4. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1995**




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

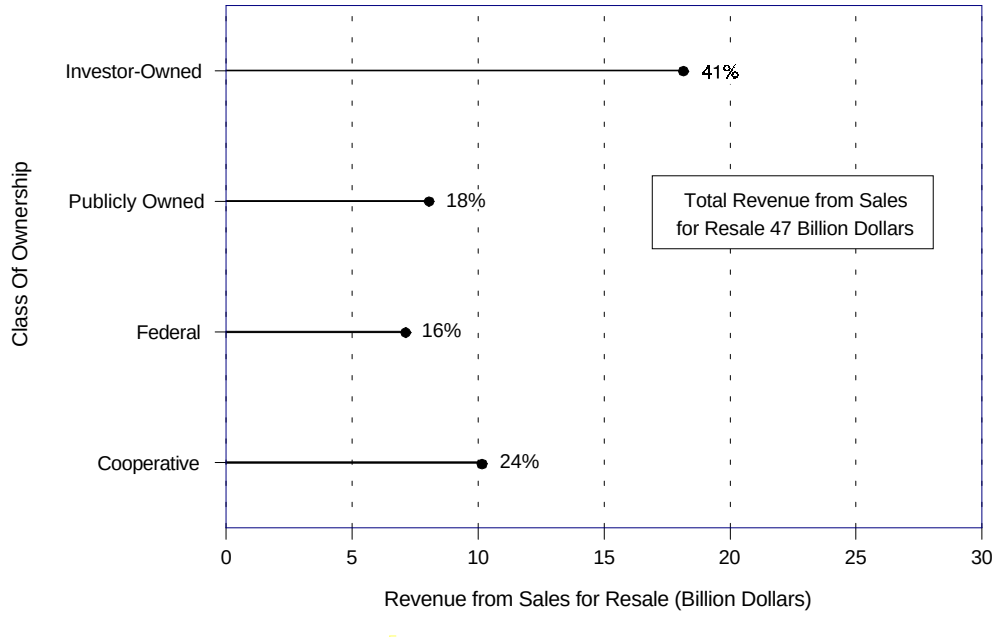
**Figure 5. U.S. Electric Utility Sales for Resale by Class of Ownership, 1995**




Notes: ●Data are preliminary. ●Totals may not equal sum of components because of independent rounding. ●Power Marketers are not shown this year.

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

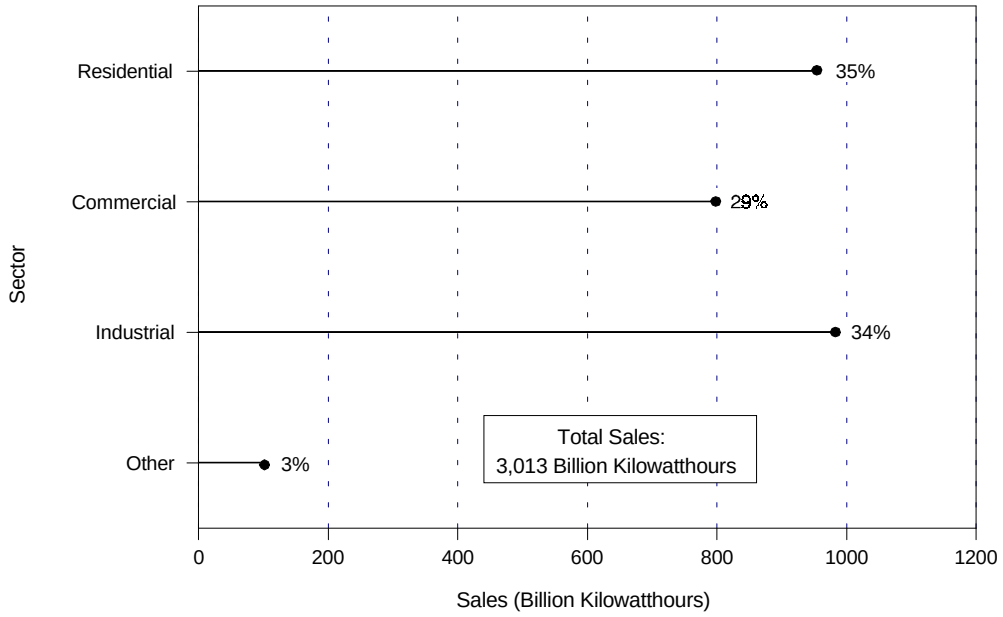
**Figure 6. Revenue from U.S. Electric Utility Sales for Resale by Class of Ownership, 1995**




Notes: ●Data are preliminary. ●Totals may not equal sum of components because of independent rounding. ●Power Marketers are not shown this year.

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

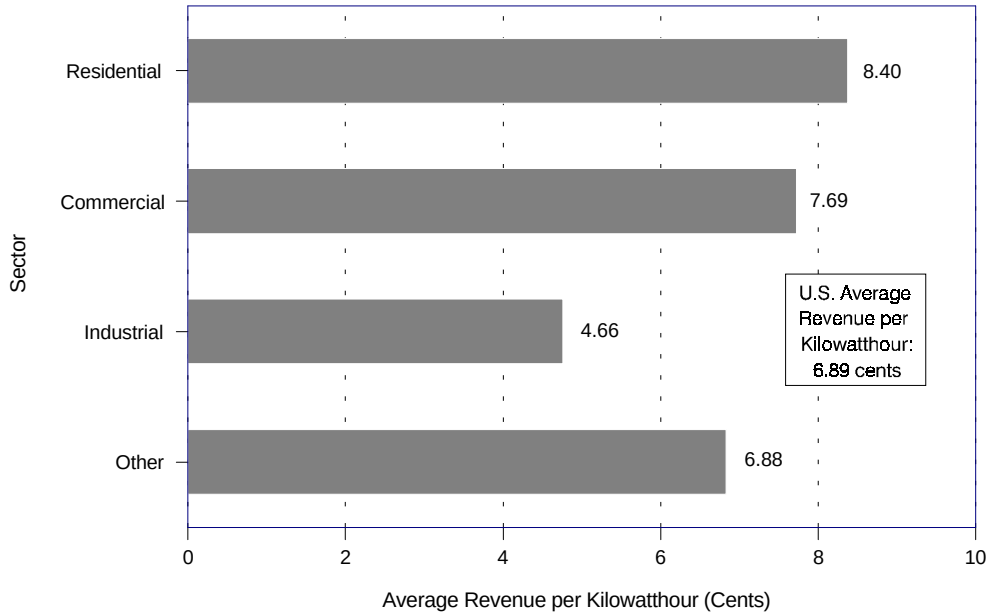
**Figure 7. U.S. Electric Utility Sales to Ultimate Consumers by Sector, 1995**




Notes: ●Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. ●Data are preliminary. ●Totals may not equal sum of components because of independent rounding.

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

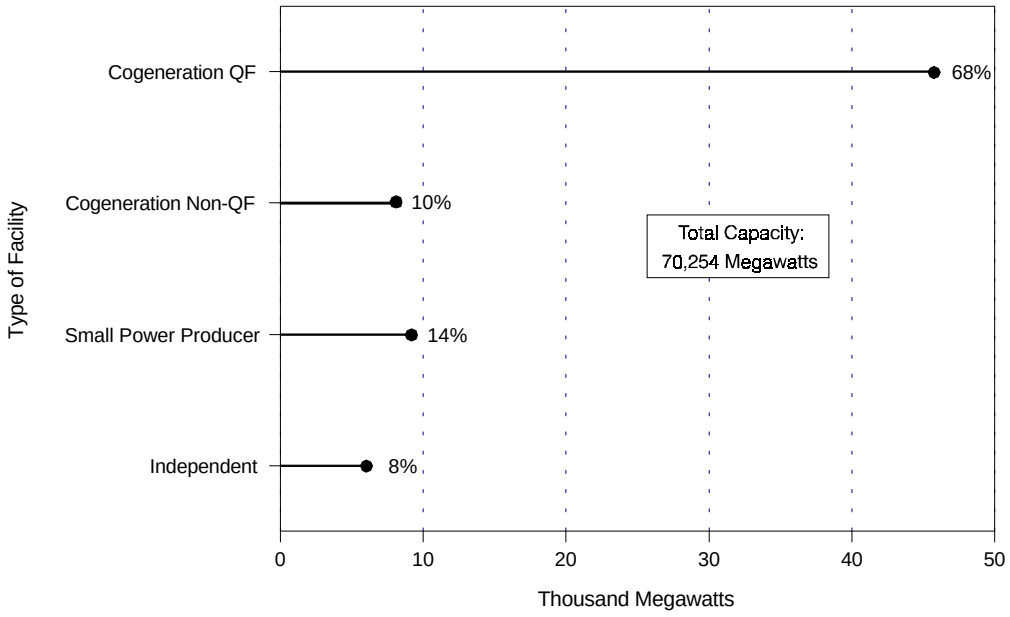
**Figure 8. U.S. Electric Utility Average Revenue per Kilowatthour by Sector, 1995**




Notes: ●Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. ●Data are preliminary.

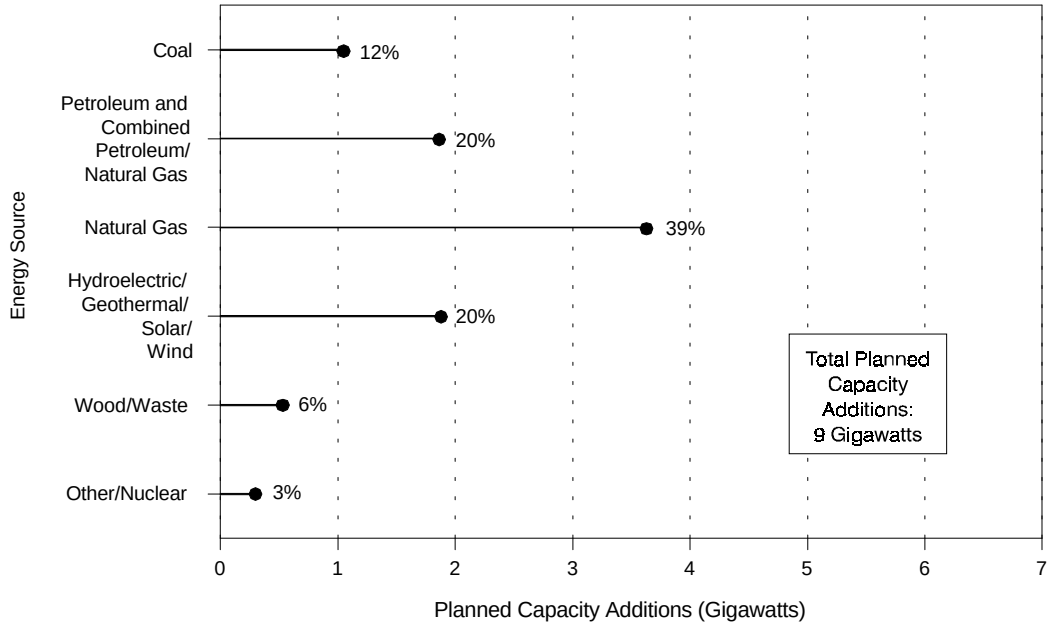
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

**Figure 9. Installed Capacity at U.S. Nonutility Generating Facilities by Type of Facility, 1995**




QF = Qualifying Facility.
Notes: ●Data are final. ●Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

**Figure 10. Planned Capacity Additions for U.S. Nonutility Generating Facilities by Energy Source, as of December 31, 1995**




Notes: ●Totals may not equal sum of components because of independent rounding. ●Other includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor. ●Data for planned capacity additions represent all planned generating facilities that meet one or more of three criteria presented in Chapter 6, "Nonutility Power Producers." ●Data are final.
Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

## Table 1. Electric Power Industry Summary Statistics for the United States, 1994 and 1995

| Item | 1994 | 1995 | Percent Change |
|---|---|---|---|
| **Electric Power Industry**[1] | | | |
| **Generating Capability (megawatts)**[2] | R 762,408 | 769,530 | 0.9 |
| **Net Generation (million kilowatthours)** | 3,253,799 | 3,356,418 | 3.2 |
| **Emissions (thousand short tons)** | | | |
| Sulfur Dioxide (SO2) | 15,291 | 12,317 | –19.4 |
| Nitrogen Oxides (NOX) | 8,250 | 8,310 | .7 |
| Carbon Dioxide (CO2) | 2,392,157 | 2,379,238 | –.5 |
| **Electric Utilities** | | | |
| **Generating Capability (megawatts)**[2 3] | R 700,623 | 706,112 | .8 |
| Coal | 300,488 | 300,604 | — |
| Petroleum | 69,918 | 64,453 | –7.8 |
| Gas | R 133,143 | 142,554 | 7.1 |
| Nuclear | 99,148 | 99,515 | .4 |
| Renewable | | | |
| Hydroelectric (conventional) | R 74,786 | 75,274 | .7 |
| Geothermal | 1,747 | 1,747 | — |
| Biomass[4] | 515 | 567 | 10.1 |
| Wind | 8 | 8 | — |
| Solar Thermal | — | — | — |
| Photovoltaic | 4 | 4 | — |
| Hydroelectric Pumped Storage | R 20,867 | 21,387 | 2.5 |
| **Net Generation (million kilowatthours)** | 2,910,712 | 2,994,529 | 2.9 |
| Coal | 1,635,493 | 1,652,914 | 1.1 |
| Petroleum[5] | 91,039 | 60,844 | –33.2 |
| Gas | 291,115 | 307,306 | 5.6 |
| Nuclear | 640,440 | 673,402 | 5.1 |
| Renewable | | | |
| Hydroelectric (conventional) | 247,071 | 296,378 | 20.0 |
| Geothermal | 6,941 | 4,745 | –31.6 |
| Biomass[4] | 1,988 | 1,649 | –17.1 |
| Wind | ** | 11 | 3,566.7 |
| Solar Thermal | — | — | — |
| Photovoltaic | 3 | 4 | 33.3 |
| Hydroelectric Pumped Storage[6] | –3,378 | –2,725 | –19.3 |
| **Consumption** | | | |
| Coal (million short tons) | 817 | 829 | 1.5 |
| Petroleum (million barrels)[7] | 151 | 102 | –32.5 |
| Gas (billion cubic feet) | 2,987 | 3,197 | 7.0 |
| **Stocks (Year End)** | | | |
| Coal (million short tons) | 127 | 126 | –.8 |
| Petroleum (million barrels)[8] | 63 | 50 | –20.6 |
| **Receipts** | | | |
| Coal (million short tons) | 832 | 827 | –.6 |
| Petroleum (million barrels)[9] | 143 | 84 | –41.3 |
| Gas (billion cubic feet)[10] | 2,864 | 3,023 | 5.6 |
| **Cost (cents per million Btu)**[11] | | | |
| Coal | 135.5 | 131.8 | –2.7 |
| Petroleum[12] | 248.8 | 267.9 | 7.7 |
| Gas | 223.0 | 198.4 | –11.0 |
| **Sales To Ultimate Consumers (million kilowatthours)** | 2,934,563 | 3,013,411 | 2.7 |
| Residential | 1,008,482 | 1,042,565 | 3.4 |
| Commercial | 820,269 | 862,841 | 5.2 |
| Industrial | 1,007,981 | 1,012,597 | .5 |
| Other[13] | 97,830 | 95,407 | –2.5 |
| **Revenue From Ultimate Consumers (million dollars)** | 202,706 | 207,732 | 2.5 |
| Residential | 84,552 | 87,616 | 3.6 |
| Commercial | 63,396 | 66,371 | 4.7 |
| Industrial | 48,069 | 47,177 | –1.9 |
| Other[13] | 6,689 | 6,568 | –1.8 |
| **Average Revenue per Kilowatthour (cents)** | 6.91 | 6.89 | –.3 |
| Residential | 8.38 | 8.40 | .2 |
| Commercial | 7.73 | 7.69 | –.5 |
| Industrial | 4.77 | 4.66 | –2.3 |
| Other[13] | 6.84 | 6.88 | .6 |
| **Net Electric Plant Inc Fuel (million dollars)** | | | |
| Major Investor Owned | 372,593 | 371,402 | –.3 |
| Major Publicly Owned Generator/Nongenerator | 69,057 | 63,305 | –8.3 |
| **Emissions (thousand short tons)**[14] | | | |
| Sulfur Dioxide (SO2) | 14,377 | 11,571 | –19.5 |
| Nitrogen Oxides (NOX) | 7,168 | 7,135 | –.5 |
| Carbon Dioxide (CO2) | 1,972,001 | 1,967,669 | –.2 |
| **Noncoincidental Summer Peak Load (megawatts)** | 585,844 | 620,871 | 5.9 |
| **DSM Actual Peak Load Reductions (megawatts)** | 25,001 | 29,561 | 18.2 |
| **DSM Energy Savings (million kilowatthours)** | 52,483 | 57,421 | 9.4 |

## Table 1. Electric Power Industry Summary Statistics for the United States, 1994 and 1995 (Continued)

| Item | 1994 | 1995 | Percent Change |
|---|---|---|---|
| **Nonutility Power Producers** | | | |
| **Installed Capacity (megawatts)** | 68,461 | 70,254 | 2.6 |
| Coal[15] | 10,372 | 10,454 | .8 |
| Petroleum Only[16] | 2,262 | 2,358 | 4.2 |
| Gas Only[17] | 28,055 | 29,272 | 4.3 |
| Petroleum/Natural Gas (combined) | 9,820 | 10,479 | 6.7 |
| Nuclear[18] | — | — | — |
| Renewable | | | |
| Hydroelectric (conventional) | 3,364 | 3,399 | 1.0 |
| Geothermal | 1,335 | 1,295 | –3.0 |
| Biomass[4] | 10,566 | 10,347 | –2.1 |
| Wind | 1,737 | 1,723 | –.8 |
| Solar Thermal | 354 | 354 | — |
| Photovoltaic | * | — | — |
| Other[19] | 597 | 574 | –3.9 |
| **Gross Generation (million kilowatthours)** | 354,925 | 374,438 | 5.5 |
| Coal[15] | 59,035 | 57,668 | –2.3 |
| Petroleum[16] | 15,069 | 16,987 | 12.7 |
| Gas[17] | 192,214 | 210,332 | 9.4 |
| Nuclear[18] | 54 | — | — |
| Renewable | | | |
| Hydroelectric (conventional) | 13,227 | 14,774 | 11.7 |
| Geothermal | 10,122 | 9,912 | –2.1 |
| Biomass[4] | 57,392 | 56,975 | –.7 |
| Wind | 3,482 | 3,185 | –8.5 |
| Solar Thermal | 824 | 824 | — |
| Photovoltaic | — | — | — |
| Other[19] | 3,507 | 3,780 | 7.8 |
| **Consumption** | | | |
| Coal (Thousand short tons) | 52,261 | 47,849 | –8.4 |
| Petroleum (Thousand barrels)[20] | 40,460 | 39,075 | –3.4 |
| Natural Gas (Million cubic feet) | 2,149,246 | 2,311,187 | 7.5 |
| Other Gas (Million cubic feet)[21] | 1,586,185 | 1,604,427 | 1.2 |
| **Supply and Disposition (million kilowatthours)** | | | |
| Gross Generation | 354,925 | 374,438 | 5.5 |
| Receipts[22] | 94,166 | 89,919 | –4.5 |
| Deliveries[23] | 222,315 | 232,049 | 4.4 |
| Facility Use | 226,777 | 232,308 | 2.4 |
| **Emissions (thousand short tons)**[24] | | | |
| Sulfur Dioxide (SO2) | 1,424 | 1,217 | –14.5 |
| Nitrogen Oxides (NOX) | 1,335 | 1,440 | 7.9 |
| Carbon Dioxide (CO2) | 567,281 | 556,324 | –1.9 |

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 Net summer capability based on primary energy source; waste heat, 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.
4 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and/or other waste.
5 Includes petroleum coke.
6 Represents total pumped storage facility production minus energy used for pumping. Negative generation denotes that electric power consumed for plant use exceeds gross generation.
7 Does not include petroleum coke consumption of 875 thousand short tons in 1994 and 761 thousand short tons in 1995.
8 Does not include petroleum coke stocks of 69 thousand short tons at year end 1994 and 65 thousand short tons at year end 1995.
9 Does not include petroleum coke receipts of 1,123 thousand short tons in 1994 and 1,263 thousand short tons in 1995.
10 Includes small amounts of coke-oven, refinery, and blast furnance gas.
11 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.
12 Does not include petroleum coke cost of 68.9 cents per million Btu in 1994 and 65.2 cents per million Btu in 1995.
13 Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
14 Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. As of 1993, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been changed--historical data were revised to reflect that change--see the Technical Notes for more information.
15 Includes coal, anthracite culm, coke breeze, fine coal and coal waste.
16 Includes petroleum coke, diesel, kerosene, and petroleum sludge and tar.
17 Includes natural gas, butane, ethane, propane, waste heat and waste gases.
18 Nuclear reactor and generator at Argonne National Laboratory used primarily for research and development in testing reactor fuels as well as for training. The generation from the unit is used for internal consumption.
19 Includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
20 Does not include petroleum coke consumption of 4,740 thousand short tons for 1994, and 4,188 thousand short tons for 1995.
21 Includes butane, ethane, propane, and other gases.
22 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
23 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-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. In addition, since the frame for the Form EIA-867 is derived from utility surveys, the Form EIA-867 universe lags 1 year.

24 As of 1993, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been changed--historical data were revised to reflect that change--see Technical Notes for more information.

R = Revised data.

NM = Calculation not meaningful.

* = Less than 0.5 megawatts.

** = Less than 0.5 million kilowatthours.

Notes: •Data for nonutility power producers, demand-side management, emissions, sales to ultimate consumers, revenue from sales, and average revenue per kilowatthour are preliminary for 1995; 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-759, ''Monthly Power Plant Report''; Form EIA-860, ''Annual Electric Generator Report''; Form EIA-861, ''Annual Electric Utility Report''; Form EIA-767, ''Steam-Electric Plant Operation and Design Report''; Form EIA-867, ''Annual Nonutility Power Producer Report.'' •Federal Energy Regulatory Commission (FERC) Form 423, ''Monthly Report of Cost and Quality of Fuels for Electric Plants.'' •Data for 1995: Form EIA-411, ''Coordinated Bulk Power Supply Programs''; Data for 1994: Department of Energy, Office of Emergency Policy, Form OE-411, ''Coordinated Bulk Power Supply Program.''

# 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 forms of energy 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, transmission and distribution will likely remain as regulated and noncompetitive functions. However, 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, Standard Industrial Classification (SIC) 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 (SIC codes 1 through 39). 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. Transmission and distribution, being natural monopolies, 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 owner-

ship 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 3,200) that own and/or operate facilities within the United States, its territories, and Puerto Rico.[8] 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*[9]

**Table 2. U.S. Electric Utility Sales to Ultimate Consumers and Associated Revenue by Sector, 1991 Through 1995**

| Item | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Sales (million kilowatthours)** | | | | | |
| Residential | 955,417 | 935,939 | 994,781 | 1,008,482 | 1,042,565 |
| Commercial | 765,664 | 761,271 | 794,573 | 820,269 | 862,841 |
| Industrial | 946,583 | 972,714 | 977,164 | 1,007,981 | 1,012,597 |
| Other[1] | 94,339 | 93,442 | 94,944 | 97,830 | 95,407 |
| **U.S. Total** | **2,762,003** | **2,763,365** | **2,861,462** | **2,934,563** | **3,013,411** |
| **Revenue (million dollars)** | | | | | |
| Residential | 76,828 | 76,848 | 82,814 | 84,552 | 87,616 |
| Commercial | 57,655 | 58,343 | 61,521 | 63,396 | 66,371 |
| Industrial | 45,737 | 46,993 | 47,357 | 48,069 | 47,177 |
| Other[1] | 6,138 | 6,296 | 6,528 | 6,689 | 6,568 |
| **U.S. Total** | **186,359** | **188,480** | **198,220** | **202,706** | **207,732** |

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data for 1995 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

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

[9] 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 3. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, 1991 Through 1995
(Cents)

| Sector | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| Residential | 8.04 | 8.21 | 8.32 | 8.38 | 8.40 |
| Commercial | 7.53 | 7.66 | 7.74 | 7.73 | 7.69 |
| Industrial | 4.83 | 4.83 | 4.85 | 4.77 | 4.66 |
| Other[1] | 6.51 | 6.74 | 6.88 | 6.84 | 6.88 |
| **All Sectors** | **6.75** | **6.82** | **6.93** | **6.91** | **6.89** |

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

Notes: •Data for 1995 are preliminary; data for prior years are final. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. •Totals may not equal sum of components because of independent rounding.

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

## Table 4. U.S. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1994 and 1995

(Million Kilowatthours)

| Census Division State | All Sectors | | Residential | | Commercial | | Industrial | | Other[1] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 |
| **New England** | **106,317** | **106,780** | **38,536** | **38,186** | **40,398** | **41,162** | **25,575** | **25,986** | **1,809** | **1,447** |
| Connecticut | 28,026 | 27,970 | 10,898 | 10,760 | 10,845 | 10,926 | 5,917 | 5,913 | 366 | 370 |
| Maine | 11,606 | 11,561 | 3,692 | 3,629 | 2,812 | 2,835 | 4,952 | 4,959 | 151 | 138 |
| Massachusetts | 46,091 | 46,502 | 16,049 | 15,988 | 19,371 | 19,945 | 9,710 | 9,969 | 961 | 600 |
| New Hampshire | 8,956 | 9,007 | 3,431 | 3,364 | 3,221 | 3,226 | 2,182 | 2,286 | 122 | 131 |
| Rhode Island | 6,572 | 6,636 | 2,457 | 2,472 | 2,563 | 2,625 | 1,378 | 1,374 | 174 | 165 |
| Vermont | 5,067 | 5,104 | 2,009 | 1,973 | 1,586 | 1,605 | 1,435 | 1,484 | 36 | 42 |
| **Middle Atlantic** | **320,479** | **323,475** | **104,497** | **105,159** | **111,580** | **117,086** | **89,794** | **86,834** | **14,608** | **14,396** |
| New Jersey | 66,258 | 66,754 | 22,154 | 22,470 | 29,358 | 29,792 | 14,251 | 13,989 | 495 | 504 |
| New York | 131,177 | 130,471 | 40,105 | 39,887 | 48,828 | 52,751 | 29,467 | 25,317 | 12,777 | 12,515 |
| Pennsylvania | 123,045 | 126,251 | 42,239 | 42,802 | 33,395 | 34,544 | 46,076 | 47,528 | 1,336 | 1,377 |
| **East North Central** | **506,246** | **524,526** | **147,380** | **156,213** | **131,968** | **137,127** | **211,969** | **216,071** | **14,930** | **15,115** |
| Illinois | 121,490 | 126,231 | 35,706 | 38,386 | 35,663 | 37,261 | 41,765 | 42,207 | 8,356 | 8,377 |
| Indiana | 83,808 | 87,006 | 25,048 | 26,561 | 17,462 | 18,121 | 40,763 | 41,779 | 534 | 546 |
| Michigan | 91,160 | 94,701 | 27,174 | 28,623 | 30,412 | 31,306 | 32,717 | 33,921 | 857 | 852 |
| Ohio | 154,377 | 158,621 | 41,791 | 44,008 | 34,053 | 35,546 | 74,010 | 74,474 | 4,522 | 4,592 |
| Wisconsin | 55,412 | 57,967 | 17,660 | 18,635 | 14,378 | 14,893 | 22,714 | 23,690 | 659 | 749 |
| **West North Central** | **208,229** | **217,646** | **75,025** | **78,796** | **56,811** | **59,659** | **70,901** | **73,571** | **5,493** | **5,621** |
| Iowa | 33,039 | 34,301 | 11,062 | 11,640 | 7,477 | 7,607 | 13,224 | 13,771 | 1,276 | 1,283 |
| Kansas | 29,614 | 30,357 | 10,131 | 10,356 | 10,111 | 10,273 | 9,001 | 9,356 | 371 | 372 |
| Minnesota | 51,155 | 53,958 | 16,007 | 16,975 | 8,997 | 9,700 | 25,451 | 26,577 | 701 | 707 |
| Missouri | 59,693 | 62,841 | 24,057 | 25,577 | 20,614 | 21,767 | 14,106 | 14,572 | 916 | 925 |
| Nebraska | 19,873 | 20,892 | 7,379 | 7,597 | 5,809 | 5,986 | 5,345 | 5,802 | 1,340 | 1,508 |
| North Dakota | 7,681 | 7,883 | 3,243 | 3,384 | 1,884 | 2,237 | 2,011 | 1,771 | 542 | 490 |
| South Dakota | 7,174 | 7,414 | 3,147 | 3,268 | 1,919 | 2,088 | 1,762 | 1,722 | 346 | 335 |
| **South Atlantic** | **592,436** | **620,624** | **237,790** | **252,129** | **176,978** | **194,932** | **158,909** | **154,100** | **18,758** | **19,464** |
| Delaware | 9,299 | 9,580 | 3,107 | 3,168 | 2,685 | 2,842 | 3,447 | 3,511 | 60 | 58 |
| District of Columbia | 10,295 | 10,316 | 1,572 | 1,608 | 8,093 | 8,079 | 267 | 262 | 363 | 366 |
| Florida | 159,544 | 167,492 | 80,595 | 85,770 | 57,447 | 60,079 | 16,513 | 16,473 | 4,989 | 5,171 |
| Georgia | 89,913 | 96,192 | 32,735 | 35,812 | 26,161 | 27,741 | 29,942 | 31,493 | 1,075 | 1,145 |
| Maryland | 54,752 | 56,159 | 21,666 | 22,235 | 13,254 | 23,097 | 19,037 | 10,057 | 794 | 771 |
| North Carolina | 99,789 | 104,673 | 37,207 | 39,506 | 27,458 | 29,195 | 33,307 | 34,063 | 1,817 | 1,909 |
| South Carolina | 61,858 | 65,074 | 19,903 | 21,392 | 13,393 | 14,020 | 27,760 | 28,819 | 802 | 843 |
| Virginia | 82,210 | 85,162 | 32,343 | 33,472 | 22,948 | 24,028 | 18,154 | 18,554 | 8,766 | 9,109 |
| West Virginia | 24,776 | 25,977 | 8,663 | 9,166 | 5,539 | 5,852 | 10,482 | 10,867 | 92 | 92 |
| **East South Central** | **259,226** | **264,717** | **89,078** | **90,140** | **34,186** | **35,529** | **130,838** | **133,755** | **5,124** | **5,292** |
| Alabama | 67,581 | 70,005 | 23,159 | 24,313 | 11,844 | 12,284 | 31,919 | 32,846 | 659 | 561 |
| Kentucky | 72,485 | 74,843 | 19,481 | 20,704 | 10,095 | 10,531 | 40,049 | 40,607 | 2,861 | 3,001 |
| Mississippi | 36,627 | 37,839 | 13,642 | 14,157 | 7,094 | 7,538 | 15,256 | 15,474 | 635 | 671 |
| Tennessee | 82,533 | 82,030 | 32,797 | 30,967 | 5,154 | 5,176 | 43,614 | 44,828 | 968 | 1,060 |
| **West South Central** | **402,074** | **412,069** | **140,191** | **145,614** | **99,494** | **102,405** | **145,446** | **146,965** | **16,942** | **17,086** |
| Arkansas | 32,619 | 34,669 | 11,642 | 12,417 | 6,866 | 7,147 | 13,526 | 14,483 | 585 | 622 |
| Louisiana | 70,132 | 72,729 | 22,629 | 24,047 | 15,041 | 15,563 | 29,870 | 30,674 | 2,593 | 2,444 |
| Oklahoma | 41,143 | 41,392 | 16,128 | 16,319 | 11,121 | 11,114 | 11,721 | 11,714 | 2,173 | 2,244 |
| Texas | 258,180 | 263,279 | 89,793 | 92,831 | 66,467 | 68,580 | 90,329 | 90,093 | 11,591 | 11,775 |
| **Mountain** | **180,286** | **183,070** | **56,738** | **56,765** | **54,820** | **55,845** | **61,247** | **63,483** | **7,480** | **6,976** |
| Arizona | 47,282 | 48,589 | 18,212 | 18,036 | 15,625 | 16,290 | 11,303 | 11,992 | 2,142 | 2,272 |
| Colorado | 34,502 | 34,734 | 10,939 | 11,138 | 12,953 | 13,259 | 9,620 | 9,455 | 990 | 882 |
| Idaho | 19,879 | 19,621 | 6,222 | 6,193 | 5,638 | 5,291 | 7,647 | 7,844 | 373 | 294 |
| Montana | 13,184 | 13,418 | 3,567 | 3,640 | 3,096 | 3,133 | 5,961 | 6,367 | 561 | 278 |
| Nevada | 20,036 | 20,659 | 6,845 | 6,655 | 4,612 | 4,731 | 7,775 | 8,496 | 805 | 777 |
| New Mexico | 15,859 | 16,416 | 4,080 | 4,124 | 4,970 | 5,094 | 5,184 | 5,651 | 1,625 | 1,547 |
| Utah | 17,847 | 18,434 | 5,009 | 5,040 | 5,500 | 5,623 | 6,498 | 6,957 | 841 | 814 |
| Wyoming | 11,696 | 11,198 | 1,865 | 1,939 | 2,428 | 2,424 | 7,260 | 6,722 | 144 | 113 |
| **Pacific** | **345,788** | **346,683** | **115,001** | **115,245** | **109,337** | **114,175** | **109,001** | **107,483** | **12,450** | **9,781** |
| California | 213,684 | 212,605 | 68,866 | 68,783 | 76,925 | 80,874 | 59,864 | 57,367 | 8,030 | 5,580 |
| Oregon | 44,971 | 45,725 | 16,462 | 16,315 | 12,660 | 12,900 | 15,072 | 15,839 | 777 | 672 |
| Washington | 87,133 | 88,353 | 29,673 | 30,147 | 19,752 | 20,401 | 34,065 | 34,276 | 3,643 | 3,528 |
| **Pacific Noncontiguous** | **13,482** | **13,819** | **4,245** | **4,319** | **4,698** | **4,921** | **4,302** | **4,349** | **237** | **230** |
| Alaska | 4,533 | 4,632 | 1,688 | 1,713 | 2,155 | 2,200 | 511 | 546 | 179 | 172 |
| Hawaii | 8,948 | 9,188 | 2,557 | 2,606 | 2,543 | 2,721 | 3,791 | 3,803 | 58 | 57 |
| **U. S. Total** | **2,934,563** | **3,013,411** | **1,008,482** | **1,042,565** | **820,269** | **862,841** | **1,007,981** | **1,012,597** | **97,830** | **95,407** |

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

Notes: •Data for 1995 are preliminary; data for prior years 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 5. Number of Ultimate Consumers Served by U.S. Electric Utilities by Sector, Census Division, and State, 1994 and 1995

(Thousands)

| Census Division State | All Sectors | | Residential | | Commercial | | Industrial | | Other[1] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 |
| **New England** | **6,202** | **6,245** | **5,477** | **5,521** | **649** | **651** | **29** | **30** | **47** | **44** |
| Connecticut | 1,457 | 1,469 | 1,321 | 1,332 | 125 | 126 | 6 | 6 | 5 | 5 |
| Maine | 687 | 693 | 595 | 599 | 71 | 72 | 3 | 3 | 18 | 18 |
| Massachusetts | 2,719 | 2,730 | 2,395 | 2,410 | 296 | 295 | 14 | 14 | 14 | 12 |
| New Hampshire | 586 | 593 | 502 | 508 | 75 | 77 | 3 | 3 | 5 | 5 |
| Rhode Island | 444 | 448 | 396 | 401 | 45 | 44 | 3 | 3 | 1 | 1 |
| Vermont | 309 | 312 | 268 | 271 | 37 | 38 | 1 | 1 | 3 | 3 |
| **Middle Atlantic** | **16,060** | **16,184** | **14,199** | **14,301** | **1,759** | **1,776** | **54** | **57** | **48** | **50** |
| New Jersey | 3,381 | 3,415 | 2,976 | 3,005 | 381 | 386 | 14 | 14 | 10 | 10 |
| New York | 7,296 | 7,340 | 6,432 | 6,469 | 822 | 824 | 12 | 15 | 30 | 32 |
| Pennsylvania | 5,383 | 5,429 | 4,791 | 4,827 | 556 | 565 | 29 | 29 | 8 | 8 |
| **East North Central** | **19,146** | **19,422** | **17,149** | **17,385** | **1,847** | **1,881** | **72** | **74** | **77** | **82** |
| Illinois | 5,002 | 5,053 | 4,516 | 4,561 | 458 | 462 | 5 | 5 | 23 | 25 |
| Indiana | 2,592 | 2,636 | 2,311 | 2,349 | 255 | 261 | 18 | 17 | 8 | 9 |
| Michigan | 4,258 | 4,316 | 3,818 | 3,867 | 411 | 418 | 13 | 13 | 16 | 18 |
| Ohio | 4,911 | 4,972 | 4,385 | 4,437 | 477 | 485 | 31 | 31 | 18 | 18 |
| Wisconsin | 2,383 | 2,444 | 2,118 | 2,170 | 246 | 254 | 6 | 7 | 12 | 12 |
| **West North Central** | **8,756** | **8,914** | **7,587** | **7,717** | **1,005** | **1,031** | **48** | **49** | **116** | **116** |
| Iowa | 1,348 | 1,363 | 1,169 | 1,181 | 160 | 163 | 4 | 4 | 15 | 15 |
| Kansas | 1,252 | 1,267 | 1,063 | 1,075 | 167 | 167 | 14 | 16 | 9 | 9 |
| Minnesota | 2,110 | 2,144 | 1,866 | 1,894 | 209 | 215 | 10 | 9 | 24 | 25 |
| Missouri | 2,541 | 2,611 | 2,244 | 2,303 | 272 | 284 | 11 | 11 | 13 | 13 |
| Nebraska | 832 | 843 | 676 | 685 | 110 | 113 | 5 | 6 | 41 | 38 |
| North Dakota | 323 | 327 | 273 | 276 | 43 | 44 | 2 | 2 | 5 | 5 |
| South Dakota | 351 | 359 | 297 | 303 | 43 | 45 | 2 | 2 | 8 | 10 |
| **South Atlantic** | **22,037** | **22,500** | **19,423** | **19,837** | **2,377** | **2,426** | **82** | **78** | **156** | **158** |
| Delaware | 340 | 346 | 305 | 310 | 33 | 34 | 1 | 1 | 1 | 1 |
| District of Columbia | 220 | 219 | 193 | 192 | 27 | 27 | * | * | * | * |
| Florida | 7,179 | 7,335 | 6,340 | 6,476 | 768 | 785 | 23 | 23 | 48 | 51 |
| Georgia | 3,253 | 3,324 | 2,878 | 2,952 | 335 | 331 | 14 | 14 | 26 | 27 |
| Maryland | 2,059 | 2,099 | 1,852 | 1,886 | 195 | 204 | 11 | 7 | 1 | 1 |
| North Carolina | 3,518 | 3,607 | 3,055 | 3,134 | 424 | 436 | 13 | 13 | 26 | 24 |
| South Carolina | 1,776 | 1,813 | 1,536 | 1,567 | 222 | 229 | 4 | 4 | 12 | 12 |
| Virginia | 2,795 | 2,849 | 2,484 | 2,531 | 269 | 275 | 5 | 5 | 38 | 39 |
| West Virginia | 897 | 908 | 780 | 789 | 103 | 105 | 11 | 11 | 3 | 3 |
| **East South Central** | **7,528** | **7,696** | **6,517** | **6,652** | **897** | **924** | **70** | **70** | **45** | **50** |
| Alabama | 2,028 | 2,069 | 1,752 | 1,781 | 256 | 264 | 13 | 13 | 7 | 11 |
| Kentucky | 1,813 | 1,863 | 1,584 | 1,627 | 200 | 205 | 11 | 11 | 18 | 19 |
| Mississippi | 1,229 | 1,251 | 1,056 | 1,074 | 155 | 159 | 9 | 9 | 9 | 10 |
| Tennessee | 2,458 | 2,513 | 2,125 | 2,170 | 286 | 296 | 37 | 37 | 10 | 11 |
| **West South Central** | **12,812** | **13,042** | **11,133** | **11,334** | **1,420** | **1,439** | **129** | **126** | **129** | **142** |
| Arkansas | 1,220 | 1,249 | 1,062 | 1,086 | 122 | 125 | 25 | 25 | 11 | 14 |
| Louisiana | 1,925 | 1,949 | 1,691 | 1,713 | 201 | 198 | 15 | 14 | 18 | 23 |
| Oklahoma | 1,630 | 1,655 | 1,408 | 1,428 | 192 | 194 | 16 | 16 | 13 | 16 |
| Texas | 8,038 | 8,188 | 6,972 | 7,107 | 906 | 921 | 73 | 71 | 86 | 89 |
| **Mountain** | **6,918** | **7,118** | **5,936** | **6,106** | **800** | **823** | **38** | **37** | **144** | **152** |
| Arizona | 1,762 | 1,850 | 1,571 | 1,643 | 171 | 177 | 5 | 5 | 16 | 24 |
| Colorado | 1,796 | 1,814 | 1,493 | 1,512 | 208 | 208 | 2 | 2 | 93 | 92 |
| Idaho | 535 | 553 | 449 | 464 | 78 | 81 | 4 | 4 | 4 | 4 |
| Montana | 442 | 452 | 364 | 373 | 62 | 63 | 4 | 4 | 13 | 12 |
| Nevada | 673 | 706 | 586 | 616 | 84 | 88 | 1 | 1 | 2 | 2 |
| New Mexico | 751 | 760 | 645 | 650 | 92 | 95 | 6 | 6 | 8 | 9 |
| Utah | 706 | 726 | 623 | 640 | 66 | 68 | 12 | 12 | 5 | 5 |
| Wyoming | 253 | 257 | 205 | 207 | 40 | 42 | 4 | 3 | 4 | 4 |
| **Pacific Contiguous** | **16,383** | **16,561** | **14,349** | **14,511** | **1,893** | **1,913** | **60** | **58** | **81** | **78** |
| California | 12,455 | 12,550 | 10,897 | 10,987 | 1,471 | 1,480 | 39 | 38 | 49 | 45 |
| Oregon | 1,472 | 1,500 | 1,271 | 1,299 | 181 | 184 | 7 | 7 | 13 | 10 |
| Washington | 2,456 | 2,511 | 2,181 | 2,226 | 242 | 249 | 14 | 13 | 19 | 23 |
| **Pacific Noncontiguous** | **646** | **659** | **552** | **561** | **85** | **87** | **1** | **1** | **8** | **10** |
| Alaska | 245 | 251 | 206 | 211 | 34 | 35 | * | * | 4 | 6 |
| Hawaii | 402 | 408 | 346 | 351 | 51 | 52 | 1 | 1 | 4 | 4 |
| **U. S. Average** | **116,489** | **118,339** | **102,321** | **103,927** | **12,733** | **12,950** | **584** | **581** | **851** | **882** |

[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 for 1995 are preliminary; data for prior years are final. •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 Ultimate Consumers by Sector, Census Division, and State, 1994 and 1995

(Million Dollars)

| Census Division State | All Sectors | | Residential | | Commercial | | Industrial | | Other[1] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 |
| **New England** | **10,731** | **10,966** | **4,403** | **4,485** | **4,015** | **4,190** | **2,078** | **2,091** | **236** | **202** |
| Connecticut | 2,853 | 2,938 | 1,250 | 1,286 | 1,084 | 1,129 | 467 | 469 | 51 | 53 |
| Maine | 1,118 | 1,097 | 455 | 454 | 286 | 292 | 356 | 330 | 22 | 22 |
| Massachusetts | 4,611 | 4,704 | 1,779 | 1,799 | 1,889 | 1,980 | 822 | 839 | 121 | 86 |
| New Hampshire | 1,014 | 1,056 | 443 | 454 | 351 | 367 | 203 | 219 | 16 | 16 |
| Rhode Island | 673 | 689 | 277 | 283 | 255 | 265 | 122 | 122 | 20 | 19 |
| Vermont | 462 | 483 | 200 | 208 | 149 | 157 | 108 | 112 | 5 | 6 |
| **Middle Atlantic** | **30,670** | **31,413** | **12,026** | **12,396** | **11,353** | **12,216** | **5,862** | **5,419** | **1,429** | **1,382** |
| New Jersey | 6,665 | 6,972 | 2,556 | 2,692 | 2,889 | 3,049 | 1,132 | 1,140 | 88 | 91 |
| New York | 14,320 | 14,435 | 5,435 | 5,544 | 5,700 | 6,290 | 1,996 | 1,466 | 1,189 | 1,135 |
| Pennsylvania | 9,686 | 10,006 | 4,035 | 4,161 | 2,765 | 2,877 | 2,733 | 2,813 | 153 | 155 |
| **East North Central** | **32,448** | **33,958** | **12,337** | **13,241** | **9,655** | **10,058** | **9,443** | **9,609** | **1,013** | **1,049** |
| Illinois | 9,008 | 9,712 | 3,564 | 3,982 | 2,739 | 2,934 | 2,164 | 2,227 | 541 | 570 |
| Indiana | 4,397 | 4,557 | 1,697 | 1,790 | 1,033 | 1,072 | 1,619 | 1,645 | 48 | 50 |
| Michigan | 6,467 | 6,679 | 2,249 | 2,387 | 2,411 | 2,462 | 1,716 | 1,739 | 90 | 91 |
| Ohio | 9,553 | 9,904 | 3,576 | 3,784 | 2,628 | 2,730 | 3,061 | 3,103 | 288 | 287 |
| Wisconsin | 3,023 | 3,106 | 1,250 | 1,298 | 844 | 861 | 883 | 896 | 46 | 51 |
| **West North Central** | **12,522** | **13,041** | **5,489** | **5,779** | **3,559** | **3,733** | **3,119** | **3,176** | **356** | **354** |
| Iowa | 1,957 | 2,069 | 895 | 959 | 473 | 490 | 513 | 542 | 76 | 79 |
| Kansas | 1,957 | 1,992 | 799 | 820 | 674 | 687 | 444 | 451 | 41 | 34 |
| Minnesota | 2,880 | 3,011 | 1,146 | 1,217 | 562 | 601 | 1,122 | 1,143 | 51 | 51 |
| Missouri | 3,749 | 3,931 | 1,754 | 1,857 | 1,278 | 1,348 | 652 | 661 | 65 | 65 |
| Nebraska | 1,091 | 1,128 | 465 | 484 | 324 | 333 | 213 | 223 | 88 | 88 |
| North Dakota | 444 | 450 | 207 | 211 | 122 | 139 | 95 | 80 | 21 | 21 |
| South Dakota | 444 | 460 | 222 | 231 | 127 | 137 | 79 | 76 | 16 | 15 |
| **South Atlantic** | **38,735** | **40,774** | **18,600** | **19,847** | **11,604** | **12,824** | **7,328** | **6,890** | **1,203** | **1,213** |
| Delaware | 631 | 662 | 277 | 288 | 188 | 201 | 159 | 166 | 7 | 7 |
| District of Columbia | 733 | 735 | 117 | 123 | 578 | 578 | 12 | 11 | 24 | 23 |
| Florida | 11,103 | 11,745 | 6,271 | 6,711 | 3,649 | 3,838 | 848 | 850 | 335 | 346 |
| Georgia | 5,907 | 6,363 | 2,527 | 2,811 | 1,918 | 2,031 | 1,368 | 1,423 | 94 | 98 |
| Maryland | 3,847 | 3,964 | 1,817 | 1,875 | 953 | 1,596 | 1,008 | 425 | 68 | 68 |
| North Carolina | 6,611 | 6,885 | 3,041 | 3,207 | 1,802 | 1,888 | 1,642 | 1,652 | 126 | 138 |
| South Carolina | 3,509 | 3,703 | 1,492 | 1,611 | 853 | 890 | 1,118 | 1,153 | 47 | 49 |
| Virginia | 5,095 | 5,331 | 2,507 | 2,626 | 1,339 | 1,458 | 755 | 772 | 493 | 474 |
| West Virginia | 1,300 | 1,386 | 551 | 596 | 323 | 343 | 417 | 438 | 9 | 9 |
| **East South Central** | **13,327** | **13,421** | **5,566** | **5,617** | **2,188** | **2,252** | **5,268** | **5,233** | **305** | **319** |
| Alabama | 3,707 | 3,830 | 1,550 | 1,631 | 800 | 827 | 1,315 | 1,332 | 41 | 41 |
| Kentucky | 3,091 | 3,053 | 1,125 | 1,165 | 534 | 553 | 1,299 | 1,195 | 134 | 141 |
| Mississippi | 2,215 | 2,263 | 964 | 990 | 512 | 528 | 684 | 688 | 55 | 57 |
| Tennessee | 4,314 | 4,274 | 1,928 | 1,832 | 342 | 344 | 1,970 | 2,018 | 75 | 80 |
| **West South Central** | **25,292** | **24,735** | **11,051** | **11,011** | **6,910** | **6,744** | **6,216** | **5,899** | **1,116** | **1,081** |
| Arkansas | 2,072 | 2,174 | 940 | 991 | 472 | 488 | 622 | 653 | 38 | 42 |
| Louisiana | 4,241 | 4,190 | 1,723 | 1,745 | 1,082 | 1,055 | 1,259 | 1,219 | 177 | 170 |
| Oklahoma | 2,402 | 2,305 | 1,134 | 1,113 | 677 | 645 | 477 | 437 | 115 | 111 |
| Texas | 16,577 | 16,066 | 7,255 | 7,162 | 4,678 | 4,556 | 3,858 | 3,590 | 786 | 758 |
| **Mountain** | **11,092** | **11,084** | **4,349** | **4,325** | **3,663** | **3,693** | **2,659** | **2,672** | **421** | **395** |
| Arizona | 3,747 | 3,700 | 1,694 | 1,640 | 1,301 | 1,313 | 636 | 631 | 117 | 117 |
| Colorado | 2,096 | 2,123 | 805 | 825 | 777 | 802 | 440 | 426 | 74 | 69 |
| Idaho | 796 | 802 | 317 | 330 | 246 | 237 | 216 | 220 | 17 | 15 |
| Montana | 594 | 624 | 213 | 222 | 160 | 166 | 196 | 219 | 25 | 17 |
| Nevada | 1,277 | 1,260 | 490 | 473 | 322 | 319 | 423 | 429 | 42 | 39 |
| New Mexico | 1,127 | 1,112 | 373 | 368 | 413 | 403 | 243 | 249 | 98 | 92 |
| Utah | 956 | 979 | 346 | 349 | 323 | 333 | 249 | 259 | 38 | 37 |
| Wyoming | 499 | 484 | 113 | 118 | 122 | 119 | 255 | 239 | 9 | 8 |
| **Pacific Contiguous** | **26,468** | **26,831** | **10,221** | **10,375** | **9,945** | **10,120** | **5,720** | **5,791** | **582** | **545** |
| California | 20,900 | 21,070 | 7,869 | 7,983 | 8,383 | 8,485 | 4,246 | 4,226 | 401 | 376 |
| Oregon | 2,070 | 2,135 | 877 | 895 | 629 | 653 | 523 | 550 | 41 | 37 |
| Washington | 3,499 | 3,626 | 1,476 | 1,497 | 932 | 982 | 951 | 1,014 | 140 | 132 |
| **Pacific Noncontiguous** | **1,420** | **1,509** | **509** | **540** | **505** | **541** | **377** | **398** | **29** | **30** |
| Alaska | 465 | 471 | 191 | 192 | 208 | 210 | 43 | 46 | 23 | 23 |
| Hawaii | 956 | 1,038 | 318 | 347 | 297 | 331 | 334 | 352 | 6 | 7 |
| **U. S. Total** | **202,706** | **207,732** | **84,552** | **87,616** | **63,396** | **66,371** | **48,069** | **47,177** | **6,689** | **6,568** |

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

Notes: •Data for 1995 are preliminary; data for prior years 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 7. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, Census Division, and State, 1994 and 1995

(Cents)

| Census Division State | All Sectors | | Residential | | Commercial | | Industrial | | Other[1] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 | 1994 | 1995 |
| **New England** | **10.09** | **10.27** | **11.43** | **11.74** | **9.94** | **10.18** | **8.12** | **8.05** | **13.02** | **13.93** |
| Connecticut | 10.18 | 10.50 | 11.47 | 11.95 | 9.99 | 10.33 | 7.90 | 7.94 | 14.00 | 14.38 |
| Maine | 9.63 | 9.49 | 12.32 | 12.51 | 10.16 | 10.28 | 7.18 | 6.65 | 14.63 | 15.67 |
| Massachusetts | 10.00 | 10.12 | 11.09 | 11.25 | 9.75 | 9.93 | 8.46 | 8.42 | 12.60 | 14.29 |
| New Hampshire | 11.32 | 11.72 | 12.91 | 13.50 | 10.91 | 11.38 | 9.32 | 9.56 | 13.36 | 12.32 |
| Rhode Island | 10.24 | 10.38 | 11.26 | 11.47 | 9.95 | 10.08 | 8.86 | 8.87 | 11.23 | 11.44 |
| Vermont | 9.13 | 9.46 | 9.96 | 10.52 | 9.42 | 9.80 | 7.50 | 7.56 | 14.88 | 14.03 |
| **Middle Atlantic** | **9.57** | **9.71** | **11.51** | **11.79** | **10.17** | **10.43** | **6.53** | **6.24** | **9.79** | **9.60** |
| New Jersey | 10.06 | 10.44 | 11.54 | 11.98 | 9.84 | 10.23 | 7.94 | 8.15 | 17.70 | 18.07 |
| New York | 10.92 | 11.06 | 13.55 | 13.90 | 11.67 | 11.92 | 6.77 | 5.79 | 9.31 | 9.07 |
| Pennsylvania | 7.87 | 7.93 | 9.55 | 9.72 | 8.28 | 8.33 | 5.93 | 5.92 | 11.43 | 11.29 |
| **East North Central** | **6.41** | **6.47** | **8.37** | **8.48** | **7.32** | **7.34** | **4.45** | **4.45** | **6.79** | **6.94** |
| Illinois | 7.41 | 7.69 | 9.98 | 10.37 | 7.68 | 7.87 | 5.18 | 5.28 | 6.47 | 6.80 |
| Indiana | 5.25 | 5.24 | 6.78 | 6.74 | 5.91 | 5.92 | 3.97 | 3.94 | 9.02 | 9.12 |
| Michigan | 7.09 | 7.05 | 8.28 | 8.34 | 7.93 | 7.86 | 5.25 | 5.13 | 10.54 | 10.71 |
| Ohio | 6.19 | 6.24 | 8.56 | 8.60 | 7.72 | 7.68 | 4.14 | 4.17 | 6.36 | 6.26 |
| Wisconsin | 5.46 | 5.36 | 7.08 | 6.97 | 5.87 | 5.78 | 3.89 | 3.78 | 7.00 | 6.85 |
| **West North Central** | **6.01** | **5.99** | **7.32** | **7.33** | **6.26** | **6.26** | **4.40** | **4.32** | **6.49** | **6.29** |
| Iowa | 5.92 | 6.03 | 8.09 | 8.24 | 6.32 | 6.44 | 3.88 | 3.94 | 5.96 | 6.13 |
| Kansas | 6.61 | 6.56 | 7.89 | 7.92 | 6.66 | 6.68 | 4.93 | 4.82 | 10.94 | 9.21 |
| Minnesota | 5.63 | 5.58 | 7.16 | 7.17 | 6.25 | 6.19 | 4.41 | 4.30 | 7.21 | 7.21 |
| Missouri | 6.28 | 6.26 | 7.29 | 7.26 | 6.20 | 6.19 | 4.62 | 4.54 | 7.07 | 7.07 |
| Nebraska | 5.49 | 5.40 | 6.31 | 6.37 | 5.58 | 5.56 | 3.99 | 3.84 | 6.53 | 5.86 |
| North Dakota | 5.77 | 5.71 | 6.37 | 6.23 | 6.45 | 6.20 | 4.71 | 4.50 | 3.82 | 4.21 |
| South Dakota | 6.19 | 6.20 | 7.06 | 7.08 | 6.60 | 6.55 | 4.51 | 4.43 | 4.62 | 4.58 |
| **South Atlantic** | **6.54** | **6.57** | **7.82** | **7.87** | **6.56** | **6.58** | **4.61** | **4.47** | **6.41** | **6.23** |
| Delaware | 6.78 | 6.91 | 8.91 | 9.09 | 7.00 | 7.08 | 4.62 | 4.72 | 11.17 | 11.95 |
| District of Columbia | 7.12 | 7.12 | 7.47 | 7.62 | 7.15 | 7.15 | 4.63 | 4.36 | 6.72 | 6.33 |
| Florida | 6.96 | 7.01 | 7.78 | 7.82 | 6.35 | 6.39 | 5.13 | 5.16 | 6.72 | 6.69 |
| Georgia | 6.57 | 6.62 | 7.72 | 7.85 | 7.33 | 7.32 | 4.57 | 4.52 | 8.71 | 8.60 |
| Maryland | 7.03 | 7.06 | 8.39 | 8.43 | 7.19 | 6.91 | 5.30 | 4.23 | 8.58 | 8.79 |
| North Carolina | 6.62 | 6.58 | 8.17 | 8.12 | 6.56 | 6.47 | 4.93 | 4.85 | 6.91 | 7.21 |
| South Carolina | 5.67 | 5.69 | 7.49 | 7.53 | 6.37 | 6.35 | 4.03 | 4.00 | 5.84 | 5.87 |
| Virginia | 6.20 | 6.26 | 7.75 | 7.84 | 5.84 | 6.07 | 4.16 | 4.16 | 5.63 | 5.21 |
| West Virginia | 5.25 | 5.34 | 6.36 | 6.50 | 5.83 | 5.86 | 3.98 | 4.03 | 9.44 | 9.36 |
| **East South Central** | **5.14** | **5.07** | **6.25** | **6.23** | **6.40** | **6.34** | **4.03** | **3.91** | **5.95** | **6.04** |
| Alabama | 5.48 | 5.47 | 6.69 | 6.71 | 6.76 | 6.73 | 4.12 | 4.05 | 6.28 | 7.35 |
| Kentucky | 4.26 | 4.08 | 5.77 | 5.63 | 5.29 | 5.25 | 3.24 | 2.94 | 4.67 | 4.69 |
| Mississippi | 6.05 | 5.98 | 7.06 | 6.99 | 7.22 | 7.01 | 4.48 | 4.44 | 8.60 | 8.56 |
| Tennessee | 5.23 | 5.21 | 5.88 | 5.91 | 6.63 | 6.65 | 4.52 | 4.50 | 7.74 | 7.56 |
| **West South Central** | **6.29** | **6.00** | **7.88** | **7.56** | **6.94** | **6.59** | **4.27** | **4.01** | **6.59** | **6.33** |
| Arkansas | 6.35 | 6.27 | 8.07 | 7.98 | 6.88 | 6.83 | 4.60 | 4.51 | 6.46 | 6.68 |
| Louisiana | 6.05 | 5.76 | 7.61 | 7.26 | 7.20 | 6.78 | 4.22 | 3.97 | 6.81 | 6.97 |
| Oklahoma | 5.84 | 5.57 | 7.03 | 6.82 | 6.09 | 5.80 | 4.07 | 3.73 | 5.29 | 4.93 |
| Texas | 6.42 | 6.10 | 8.08 | 7.71 | 7.04 | 6.64 | 4.27 | 3.98 | 6.79 | 6.44 |
| **Mountain** | **6.15** | **6.05** | **7.66** | **7.62** | **6.68** | **6.61** | **4.34** | **4.21** | **5.62** | **5.66** |
| Arizona | 7.93 | 7.62 | 9.30 | 9.09 | 8.32 | 8.06 | 5.63 | 5.26 | 5.47 | 5.15 |
| Colorado | 6.07 | 6.11 | 7.36 | 7.41 | 6.00 | 6.05 | 4.58 | 4.51 | 7.43 | 7.86 |
| Idaho | 4.00 | 4.09 | 5.09 | 5.33 | 4.37 | 4.48 | 2.82 | 2.81 | 4.64 | 5.11 |
| Montana | 4.51 | 4.65 | 5.96 | 6.09 | 5.17 | 5.31 | 3.30 | 3.44 | 4.49 | 6.21 |
| Nevada | 6.37 | 6.10 | 7.16 | 7.11 | 6.97 | 6.75 | 5.45 | 5.05 | 5.19 | 5.00 |
| New Mexico | 7.11 | 6.77 | 9.14 | 8.93 | 8.30 | 7.91 | 4.70 | 4.40 | 6.05 | 5.95 |
| Utah | 5.36 | 5.31 | 6.91 | 6.93 | 5.87 | 5.93 | 3.83 | 3.72 | 4.50 | 4.52 |
| Wyoming | 4.26 | 4.32 | 6.04 | 6.09 | 5.02 | 4.91 | 3.51 | 3.55 | 6.45 | 7.16 |
| **Pacific Contiguous** | **7.65** | **7.74** | **8.89** | **9.00** | **9.10** | **8.86** | **5.25** | **5.39** | **4.67** | **5.57** |
| California | 9.78 | 9.91 | 11.43 | 11.61 | 10.90 | 10.49 | 7.09 | 7.37 | 5.00 | 6.73 |
| Oregon | 4.60 | 4.67 | 5.33 | 5.49 | 4.97 | 5.06 | 3.47 | 3.47 | 5.27 | 5.49 |
| Washington | 4.02 | 4.10 | 4.97 | 4.97 | 4.72 | 4.82 | 2.79 | 2.96 | 3.83 | 3.75 |
| **Pacific Noncontiguous** | **10.54** | **10.92** | **12.00** | **12.50** | **10.75** | **10.99** | **8.76** | **9.16** | **12.24** | **12.97** |
| Alaska | 10.25 | 10.17 | 11.32 | 11.24 | 9.66 | 9.54 | 8.37 | 8.38 | 12.57 | 13.26 |
| Hawaii | 10.68 | 11.29 | 12.45 | 13.32 | 11.67 | 12.16 | 8.82 | 9.27 | 11.21 | 12.11 |
| **U. S. Average** | **6.91** | **6.89** | **8.38** | **8.40** | **7.73** | **7.69** | **4.77** | **4.66** | **6.84** | **6.88** |

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. The average revenue for other sales may include ownership, operation, maintenance, and rental fees for equipment and/or demand and service charges.

Notes: •Data for 1995 are preliminary; data for prior years are final. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. •Totals may not equal sum of components because of independent rounding.

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.

## 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 1995. 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 1995. 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 1991 through 1995 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 3 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).

Of the 244 investor-owned electric utilities, the 179 major utilities are required to submit the FERC Form 1. These major investor-owned electric utilities represent about three-fourths of all investor-owned electric utilities. The electric utilities are required to follow the Uniform System of Accounts prescribed by the FERC (in cooperation with the National Association of Regulatory Utility Commissioners). Detailed financial statistics on investor-owned electric utilities are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*[10]

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:

- 120,000 megawatthours of sales to ultimate consumers
- 120,000 megawatthours of sales for resale.

Approximately 500 publicly owned electric utilities are required to submit the Form EIA-412. These major publicly owned electric utilities represent about one-fourth of all publicly owned electric utilities and more than 80 percent of total sales by publicly owned electric utilities to ultimate consumers. 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.*[11]

[10] Energy Information Administration (EIA), *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437(94)/1 (Washington, DC); data for 1992 and 1993 are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437/1; data for 1991 are published in the *Financial Statistics of Major Investor-Owned Electric Utilities*, DOE/EIA-0437(91)/1.

[11] Energy Information Administration (EIA), *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*, DOE/EIA-0437(94)/2; data for 1992 and 1993 are published in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*, DOE/EIA-0437/2; data for 1991 are published in the *Financial Statistics of Major Publicly Owned Electric Utilities*, DOE/EIA-0437(91)/2.

## Table 8. Composite Statement of Income for Major U.S. Investor-Owned Electric Utilities, 1991 Through 1995

(Thousand Dollars)

| Description | 1991[1] | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Operating Revenue** | **182,450,728** | **185,493,458** | **193,637,843** | **196,281,500** | **199,966,979** |
| Electric | 166,803,843 | 169,488,035 | 176,354,365 | 179,307,260 | 183,655,263 |
| Gas | 14,560,221 | 14,937,370 | 16,686,912 | 16,221,506 | 15,580,382 |
| Other Utility | 1,086,663 | 1,068,053 | 596,567 | 752,734 | 731,333 |
| **Operating Expenses** | **150,361,969** | **153,682,429** | **161,908,147** | **164,207,153** | **165,321,023** |
| Electric | 135,947,991 | 139,009,093 | 146,118,013 | 148,662,734 | 150,598,710 |
| Fuel | 31,312,220 | 30,254,398 | 31,214,057 | 30,107,888 | 29,121,982 |
| Other Operating and Maintenance | 66,645,950 | 69,212,541 | 72,561,087 | 75,021,900 | 74,525,998 |
| Depreciation[2] | 16,127,176 | 17,091,753 | 18,098,736 | 18,679,022 | 19,885,482 |
| Taxes Other Than Income Taxes | 12,270,379 | 12,760,152 | 13,040,400 | 13,275,354 | 13,519,143 |
| Regulatory Debits (net) | — | — | 676,265 | 1,143,207 | 1,555,408 |
| Income Taxes | 7,691 | 7,198 | 8,297 | 9,626 | 11,480 |
| Deferred Income Tax | 2,294,676 | 3,017,335 | 2,993,143 | 1,831,593 | 1,473,977 |
| Investment Tax Credit (Net) | –392,931,000 | –524,768,000 | –515,791,000 | –584,701,000 | –549,772,000 |
| Gas | 13,406,370 | 13,691,253 | 15,234,557 | 14,877,836 | 14,073,160 |
| Income Taxes | 309 | 280 | 252 | 465 | 532 |
| Other | 13,097,714,000 | 13,411,635,000 | 14,983,024,000 | 14,412,760,000 | 13,541,412,000 |
| Other Utility | 1,007,609 | 982,083 | 555,577 | 666,584 | 649,154 |
| Income Taxes | 4 | 27 | 11 | 15 | 6 |
| Other | **1,004,079,000** | **955,127,000** | **544,814,000** | **651,621,000** | **643,347,000** |
| **Operating Income** | 32,088,758 | 31,811,029 | 31,729,696 | 32,074,346 | 34,645,955 |
| Electric | 30,855,852 | 30,478,942 | 30,236,352 | 30,644,526 | 33,056,553 |
| Gas | 1,153,852 | 1,246,117 | 1,452,354 | 1,343,670 | 1,507,223 |
| Other | **79,055** | **85,970** | **40,990** | **86,150** | **82,180** |
| **Other Income and Deductions** | 523,325 | 1,689,045 | 1,346,398 | 1,809,553 | 1,811,414 |
| Allowance for Other Funds Used During Construction | 706,102 | 611,514 | 591,445 | 402,569 | 315,651 |
| Less Taxes | 853 | 379 | 1,120 | 478 | 351 |
| Deferred Earnings (Misc.) (acct 421) | 1,271,525 | 1,341,354 | 677,360 | 802,120 | 372,642 |
| Less Other Income and Expenses[3] | **601,723,000** | **–115,638,000** | **–1,197,174,000** | **–1,082,393,000** | **–1,473,837,000** |
| **Total Income Before Interest Charges** | **32,612,083** | **33,500,074** | **33,076,094** | **33,883,899** | **36,457,369** |
| **Net Interest Charges** | 15,736,248 | 15,223,174 | 14,700,488 | 14,161,602 | 14,421,406 |
| Interest Expense | 16,010,348 | 15,307,441 | 14,566,753 | 13,915,384 | 14,169,979 |
| Less Allowance for Borrowed Funds Used During Construction | 636 | 558 | 555 | 421 | 435 |
| Other Charges--Net | **361,424,000** | **474,080,000** | **688,756,000** | **667,046,000** | **686,814,000** |
| **Net Income Before Extraordinary Charges** | **16,875,836** | **18,276,900** | **18,375,606** | **19,722,298** | **22,035,963** |
| Less **Extraordinary Items After Taxes**[3] | **–73,829** | **–107,544** | **484,409** | **–165,288** | **–24,691** |
| **Net Income** | 16,949,664 | 18,384,444 | 17,891,198 | 19,887,586 | 22,060,655 |
| **Dividends Declared - Preferred Stock** | **1,945,213** | **2,039,449** | **1,765,286** | **1,581,940** | **1,518,904** |
| **Earnings Available for Common Stocks** | **15,004,451** | **16,344,995** | **16,125,912** | **18,305,646** | **20,541,751** |
| **Dividends Declared - Common Stock** | **14,427,570** | **14,897,608** | **15,334,377** | **15,875,659** | **16,249,715** |
| **Additions Total Earnings** | **254,189** | **2,184,266** | **296,171** | **2,063,432** | **4,281,899** |
| **Average Shares of Common Stock Outstanding** | **5,932,492** | **6,261,284** | **6,129,888** | **6,223,816** | **6,752,352** |
| **Earnings Available Per Average Common Share (Dollars)** | **2.53** | **2.61** | **2.63** | **2.94** | **3.04** |

1 Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

2 Includes amortization and depletion.

3 Other Income and Expenses and Extraordinary Items After Taxes were affected negatively by aftertax write offs, accounting adjustments, and regulatory rate decisions. The majority of the charges were directly related to the the treatment of nuclear plants.

Notes: •Data are final. •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.'' 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, 1991 Through 1995

(Thousand Dollars)

| Description | 1991[1] | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| **Utility Plant - Net** | **376,771,703** | **386,864,738** | **393,829,243** | **397,812,254** | **397,383,148** |
| Electric Utility Plant - Net | 349,611,025 | 358,300,259 | 363,829,459 | 366,936,417 | 366,116,061 |
| Electric Utility Plant | 479,822,229 | 498,118,599 | 519,207,367 | 535,928,383 | 553,857,823 |
| Construction Work in Progress | 18,077,211 | 20,648,234 | 18,048,849 | 17,148,353 | 13,523,358 |
| Less Accumulated Depreciation | 148,288,414 | 160,466,573 | 173,426,756 | 186,140,318 | 201,265,120 |
| Nuclear Fuel - Net | 6,911,645 | 6,836,719 | 5,964,178 | 5,656,878 | 5,285,850 |
| Other Utility Plant - Net | 20,249,033 | 21,727,759 | 24,035,606 | 25,218,959 | 25,981,238 |
| **Other Property and Investments** | **17,385,415** | **18,045,977** | **20,063,695** | **23,479,360** | **27,987,677** |
| **Current and Accrued Assets** | **43,357,785** | **43,447,871** | **42,409,989** | **41,262,977** | **44,139,661** |
| **Deferred Debits** | **50,024,920** | **57,993,875** | [2] **110,338,355** | **111,957,082** | **109,423,227** |
| **Total Assets and other Debits** | **487,539,823** | **506,352,461** | **566,641,282** | **574,511,673** | **578,933,714** |
| **Capitalization and Liabilities** | | | | | |
| **Capitalization** | **348,828,405** | **356,026,762** | **360,455,273** | **364,724,736** | **365,774,716** |
| Common Stock Equity (End of Year) | 151,671,304 | 156,346,650 | 160,296,897 | 164,482,824 | 170,497,132 |
| Common Stock | 99,723,170 | 103,963,697 | 107,470,838 | 109,522,096 | 111,301,825 |
| Retained Earnings (Adjusted) | 51,948,134 | 52,382,953 | 52,826,059 | 54,960,728 | 59,195,307 |
| Preferred Stock | 25,262,285 | 25,539,216 | 25,304,294 | 24,859,833 | 21,569,105 |
| Long-term Debt | 171,894,816 | 174,140,896 | 174,854,082 | 175,382,079 | 173,708,479 |
| **Current Liabilities and Deferred Credits** | **138,711,418** | **150,325,698** | **206,186,010** | **209,786,937** | **213,158,998** |
| Other Noncurrent Liabilities | 6,931,193 | 8,627,882 | 11,478,303 | 13,452,636 | 14,352,102 |
| Current and Accrued Liabilities | 43,357,436 | 45,557,601 | 48,878,976 | 48,035,058 | 49,929,403 |
| Deferred Credits | 88,422,789 | 96,140,215 | 145,828,731 | 148,299,243 | 148,877,493 |
| Accumulated Deferred Income Taxes | 59,188,298 | 65,020,984 | 104,964,188 | 107,054,667 | 108,615,175 |
| Accumulated Deferred Investment Tax Credit | 14,689,786 | 14,046,840 | 13,428,995 | 12,784,415 | 12,138,942 |
| Other Deferred Credits (Adjusted) | 14,544,705 | 17,072,392 | 27,435,549 | 28,460,160 | 28,123,375 |
| **Total Liabilities and Other Credits** | **487,539,823** | **506,352,461** | **566,641,282** | **574,511,673** | **578,933,714** |

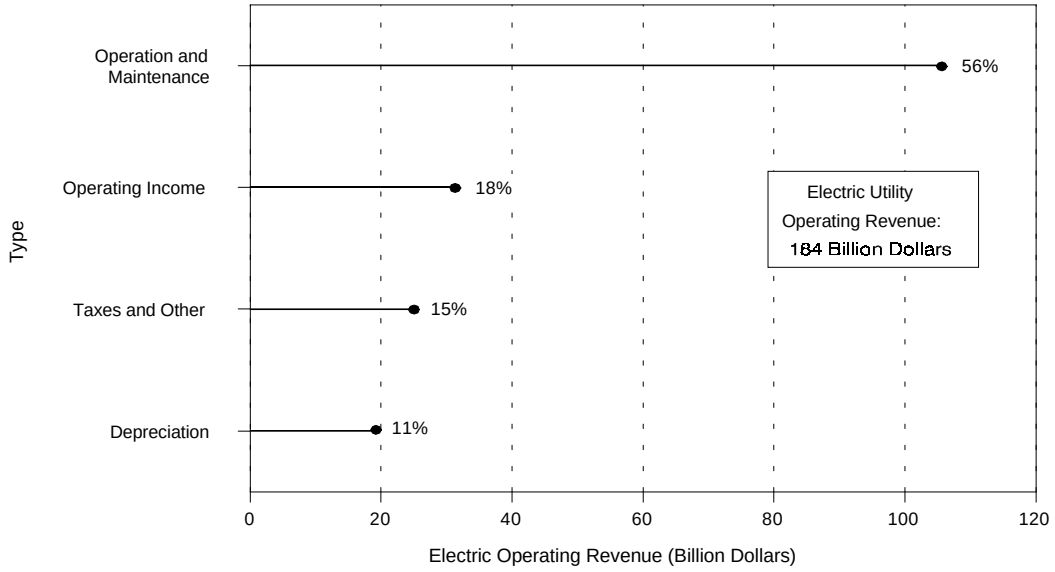
[1] Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

[2] In 1993, Other Regulatory Assets (a new line item) was added to the Balance Sheet and accounts for the large increase in Deferred Debits from 1992.

Notes: •Data are final. •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.'' See Appendix A for a detailed description of this restricted-universe census.

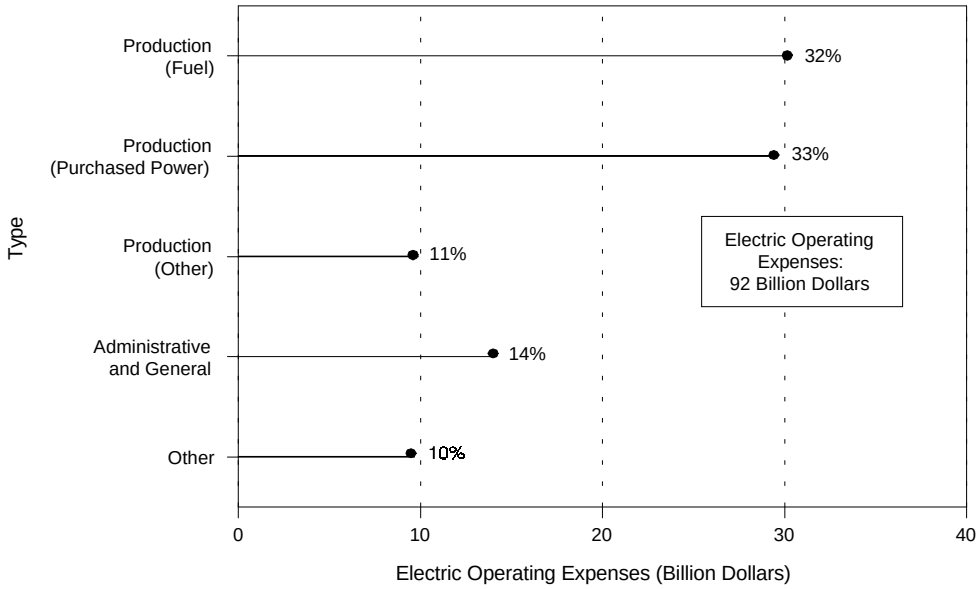
**Figure 11. Allocation of the Revenue Dollar from Electric Operations for Major U.S. Investor-Owned ElectricUtilities, 1995**




Notes: ●Depreciation includes amortization and depletion. ●Totals may not equal sum of components because of independent rounding. ●Data are final.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix A for a detailed description of this restricted-universe census.

**Figure 12. Electric Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1995**




Notes: ●Other includes transmission, distribution, customer account, customer service, and sales. ●Totals may not equal sum of components because of independent rounding. ●Data are final.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." 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, 1991 Through 1995

| Description[1] | 1991[2] | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Activity** | | | | | |
| 1. Electric Fixed Asset (Net Plant) Turnover | 0.48 | 0.47 | 0.48 | 0.49 | 0.50 |
| 2. Total Asset Turnover | .37 | .37 | .34 | .34 | .35 |
| **Leverage** | | | | | |
| 3. Current Assets to Current Liabilities | 1.00 | .95 | .87 | .86 | .88 |
| 4. Long-term Debt to Capitalization | 49.28 | 48.91 | 48.51 | 48.09 | 47.49 |
| 5. Preferred Stock to Capitalization | 7.24 | 7.17 | 7.02 | 6.82 | 5.90 |
| 6. Common Stock Equity to Capitalization | 43.48 | 43.91 | 44.47 | 45.10 | 46.61 |
| 7. Total Debt to Total Assets[3] | 36.69 | 36.13 | 32.48 | 32.35 | 31.89 |
| 8. Common Stock Equity to Total Assets | 31.11 | 30.88 | 28.29 | 28.63 | 29.45 |
| 9. Interest Coverage Before Taxes without AFUDC | 2.49 | 2.62 | 2.78 | 3.10 | 3.37 |
| **Profitability** | | | | | |
| 10. Profit Margin | 9.29 | 9.91 | 9.24 | 10.13 | 11.03 |
| 11. Return on Average Common Stock Equity[4] | 11.33 | 11.94 | 11.30 | 12.24 | 13.17 |
| 12. Return on Investment | 3.48 | 3.63 | 3.16 | 3.46 | 3.81 |

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

2 Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

3 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) were $10,895,101 for 1995; $10,448,573 for 1994; $9,210,845 for 1993; $8,791,477 for 1992; and $6,986,960 for 1991.

4 The Average Common Stock Equity is the average of the beginning and ending year balances. The value for the beginning of 1991 was $149,547,693.

AFUDC=Allowance for Funds Used During Construction.

Notes: •Data are final. •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.'' See Appendix A for a detailed description of this restricted-universe census.

## Table 11. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1991 Through 1995

(Thousand Dollars)

| Description | 1991[1] | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Utility Operating Revenues** | **182,450,728** | **185,493,458** | **193,637,843** | **196,281,500** | **199,966,979** |
| Electric Utility | 166,803,843 | 169,488,035 | 176,354,365 | 179,307,260 | 183,655,263 |
| Other Utility | 15,646,884 | 16,005,423 | 17,283,479 | 16,974,240 | 16,311,715 |
| **Utility Operating Expenses** | **150,361,969** | **153,682,429** | **161,908,147** | **164,207,153** | **165,321,023** |
| Electric Utility | 135,947,991 | 139,009,093 | 146,118,013 | 148,662,734 | 150,598,710 |
| Operation | 85,933,743 | 87,272,134 | 91,328,230 | 93,107,998 | 91,880,940 |
| Production | 66,101,528 | 66,979,805 | 68,780,803 | 69,268,652 | 68,983,410 |
| Cost of Fuel | 31,312,220 | 30,254,398 | 31,214,057 | 30,107,888 | 29,121,982 |
| Purchased Power | 24,169,252 | 26,212,238 | 27,715,512 | 29,213,084 | 29,981,379 |
| Other | 10,620,056 | 10,513,169 | 9,851,234 | 9,947,680 | 9,880,049 |
| Transmission | 1,247,286 | 1,308,101 | 1,354,058 | 1,361,080 | 1,425,058 |
| Distribution | 2,530,490 | 2,498,514 | 2,595,023 | 2,581,409 | 2,560,835 |
| Customer Accounts | 3,203,212 | 3,347,124 | 3,418,487 | 3,546,489 | 3,613,101 |
| Customer Service | 1,451,507 | 1,531,369 | 1,852,267 | 1,955,991 | 1,922,475 |
| Sales | 203,230 | 198,647 | 203,291 | 231,589 | 348,345 |
| Administrative and General | 11,196,490 | 11,408,575 | 13,124,300 | 14,162,788 | 13,027,716 |
| Maintenance | 12,024,427 | 12,194,805 | 12,446,914 | 12,021,790 | 11,767,040 |
| Depreciation | 16,127,176 | 17,091,753 | 18,098,736 | 18,679,022 | 19,885,482 |
| Taxes and Other | 21,862,645 | 22,450,401 | 24,244,133 | 24,853,924 | 27,065,248 |
| Other Utility | 14,413,979 | 14,673,336 | 15,790,134 | 15,544,420 | 14,722,314 |
| **Net Utility Operating Income** | **32,088,758** | **31,811,029** | **31,729,696** | **32,074,346** | **34,645,955** |

[1] Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

Notes: •Data are final. •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.'' 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, 1991 Through 1995

| Description | 1991[1] | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Utility Operating Revenues** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** |
| Electric Utility | 91.4 | 91.4 | 91.1 | 91.4 | 91.8 |
| Other Utility | 8.6 | 8.6 | 8.9 | 8.6 | 8.2 |
| **Utility Operating Expenses** | **82.4** | **82.9** | **83.6** | **83.7** | **82.7** |
| Electric Utility | 74.5 | 74.9 | 75.5 | 75.7 | 75.3 |
| Operation | 47.1 | 47.0 | 47.2 | 47.4 | 45.9 |
| Production | 36.2 | 36.1 | 35.5 | 35.3 | 34.5 |
| Cost of Fuel | 17.2 | 16.3 | 16.1 | 15.3 | 14.6 |
| Purchased Power | 13.2 | 14.1 | 14.3 | 14.9 | 15.0 |
| Other | 5.8 | 5.7 | 5.1 | 5.1 | 4.9 |
| Transmission | .7 | .7 | .7 | .7 | .7 |
| Distribution | 1.4 | 1.3 | 1.3 | 1.3 | 1.3 |
| Customer Accounts | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Customer Service | .8 | .8 | 1.0 | 1.0 | 1.0 |
| Sales | .1 | .1 | .1 | .1 | .2 |
| Administrative and General | 6.1 | 6.2 | 6.8 | 7.2 | 6.5 |
| Maintenance | 6.6 | 6.6 | 6.4 | 6.1 | 5.9 |
| Depreciation | 8.8 | 9.2 | 9.3 | 9.5 | 9.9 |
| Taxes and Other | 12.0 | 12.1 | 12.5 | 12.7 | 13.5 |
| Other Utility | 7.9 | 7.9 | 8.2 | 7.9 | 7.4 |
| **Net Utility Operating Income** | **17.6** | **17.1** | **16.4** | **16.3** | **17.3** |

[1] Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

Notes: •Data are final. •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.'' 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, 1991 Through 1995

(Mills per Kilowatthour)

| Plant Type | 1991[1] | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| | | | **Operation** | | |
| Nuclear | 10.49 | 10.43 | 10.20 | 9.79 | 9.43 |
| Fossil Steam | 2.29 | 2.38 | 2.37 | 2.32 | 2.38 |
| Hydroelectric[2] | 3.88 | 4.33 | 3.82 | 4.53 | 3.69 |
| Gas Turbine and Small Scale[3] | 9.61 | 10.18 | 6.47 | 4.58 | 3.57 |
| | | | **Maintenance** | | |
| Nuclear | 5.50 | 5.93 | 5.73 | 5.20 | 5.21 |
| Fossil Steam | 2.98 | 2.95 | 2.96 | 2.82 | 2.65 |
| Hydroelectric[2] | 2.89 | 3.30 | 2.65 | 2.90 | 2.19 |
| Gas Turbine and Small Scale[3] | 12.93 | 12.15 | 7.52 | 5.39 | 4.28 |
| | | | **Fuel** | | |
| Nuclear | 6.71 | 6.12 | 5.88 | 5.87 | 5.75 |
| Fossil Steam | 17.91 | 17.49 | 17.65 | 16.67 | 16.07 |
| Hydroelectric[2] | — | — | — | — | — |
| Gas Turbine and Small Scale[3] | 30.96 | 28.59 | 26.39 | 22.19 | 20.83 |
| | | | **Total[4]** | | |
| Nuclear | 22.70 | 22.48 | 21.80 | 20.86 | 20.39 |
| Fossil Steam | 23.17 | 22.83 | 22.97 | 21.80 | 21.11 |
| Hydroelectric[2] | 6.76 | 7.63 | 6.47 | 7.43 | 5.89 |
| Gas Turbine and Small Scale[3] | 53.51 | 50.92 | 40.38 | 32.16 | 28.67 |

1 Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

2 Includes Pumped Storage.

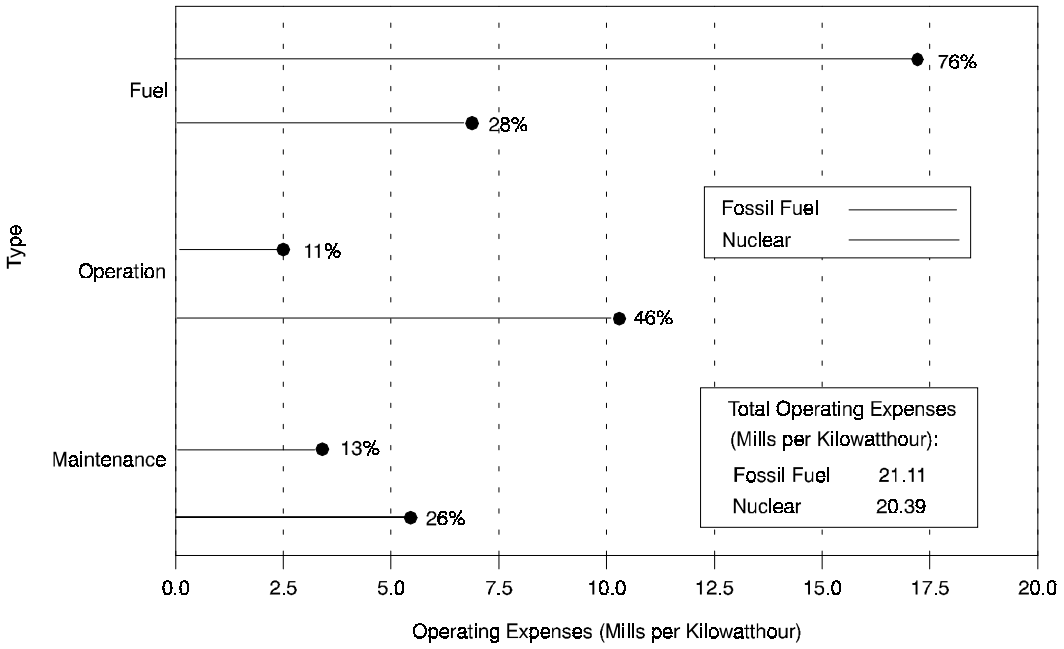
3 Includes gas turbine, internal combustion, photovoltaic, and wind plants.

4 Totals may not equal sum of components because of independent rounding.

Notes: •Data are final. •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.'' See Appendix A for a detailed description of this restricted-universe census.

**Figure 13. Average Operating Expenses of Fossil-Fueled and Nuclear Steam-Electric Plants for Major U.S. Investor-Owned Electric Utilities, 1995**




Notes: ●Data are final. ●Totals may not equal sum of components because of independent rounding.
Source: Federal Energy Regulatory Commission, FERC Form1, "Annual Report of Major Electric Utilities, Licensees and Others." 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, 1991 Through 1995

(Thousand Dollars)

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Operating Revenue - Electric** | **21,082,870** | **21,686,349** | **22,521,847** | **23,266,686** | **20,784,089** |
| **Operating Expenses - Electric** | **16,886,921** | **17,190,647** | **18,162,164** | **18,648,687** | **16,714,140** |
| **Operation Excluding Fuel** | 9,082,917 | 9,408,002 | 9,803,647 | 10,191,897 | 9,627,156 |
| Fuel | 3,072,158 | 3,119,433 | 3,437,920 | 3,385,718 | 2,394,293 |
| Maintenance | 1,446,295 | 1,564,792 | 1,565,293 | 1,584,444 | 1,362,483 |
| Depreciation and Amortization[1] | 2,300,532 | 2,417,279 | 2,596,099 | 2,720,560 | 2,574,064 |
| Taxes and Tax Equivalents | 595,719 | 681,140 | 759,205 | 766,068 | 756,144 |
| Net Contributions and Services | 389,300 | — | — | — | — |
| **Operating Income - Electric** | **4,195,949** | **4,495,703** | **4,359,683** | **4,617,999** | **4,069,949** |
| **Other Income and Deductions** | **1,843,761** | **1,628,944** | **1,219,709** | **1,098,922** | **851,380** |
| Income from Electric Plant Leased to Others | 5,942 | 15,129 | 23,576 | 30,242 | 14,714 |
| Allowance for Funds Used During Construction | 71,025 | 24,183 | 28,476 | 7,872 | 9,145 |
| Other Income Net | 1,890,138 | 1,839,484 | 1,455,984 | 1,237,067 | 1,050,093 |
| Less Other Electric Deductions | 123,345 | 249,852 | 288,325 | 176,259 | 222,573 |
| **Total Income Before Interest Charges** | **6,039,710** | **6,124,646** | **5,579,392** | **5,716,920** | **4,921,328** |
| **Net Interest Charges** | **5,205,799** | **5,025,758** | **4,682,023** | **4,681,141** | **3,896,658** |
| Interest Expenses | 4,775,003 | 4,757,583 | 4,433,067 | 4,332,296 | 3,540,396 |
| Other Income Deductions | 430,796 | 268,175 | 248,956 | 348,845 | 356,261 |
| **Net Income Before Extraordinary Charges** | **833,911** | **1,098,889** | **897,369** | **1,035,779** | **1,024,671** |
| Less **Extraordinary Items** | **65,544** | **115,275** | **214,227** | **124,211** | **–22,759** |
| **Net Income** | **768,367** | **983,613** | **683,142** | **911,568** | **1,047,430** |

[1] Nuclear fuel included in 1992, 1993, 1994, and 1995 data.

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 222 for 1995, 227 for 1994, 222 for 1993, 225 for 1992, and 218 for 1991.

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, 1991 Through 1995

(Thousand Dollars)

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| **Electric Utility Plant-Net Inc Nuclear Fuel** | **60,737,416** | **61,710,753** | **62,477,584** | **63,576,104** | **57,069,358** |
| Electric Utility Plant Inc Nuclear Fuel | 81,535,543 | 85,359,878 | 88,353,146 | 92,044,086 | 84,113,584 |
| Accumulated Provision for Depreciation and Amortization | 20,798,127 | 23,649,125 | 25,875,562 | 28,467,982 | 27,044,227 |
| **Other Property and Investments** | **17,332,581** | **18,228,937** | **20,487,402** | **20,973,996** | **18,894,421** |
| **Current and Accrued Assets** | **14,084,691** | **14,990,707** | **15,357,112** | **15,782,291** | **12,994,255** |
| **Deferred Debits** | **10,890,161** | **12,017,041** | **13,987,324** | **13,913,754** | **10,543,805** |
| **Total Assets and Other Debits** | **103,044,849** | **106,947,439** | **112,309,422** | **114,246,146** | **99,501,839** |
| **Liabilities and Other Credits** | | | | | |
| **Investment of Municipality - Surplus** | **22,222,042** | **22,823,226** | **23,527,598** | **24,518,851** | **24,190,318** |
| **Long-Term Debt** | **68,871,516** | **72,004,391** | **76,168,783** | **76,815,309** | **63,409,759** |
| **Other Noncurrent Liabilities** | **622,507** | **698,351** | **590,789** | **701,406** | **711,796** |
| **Current and Accrued Liabilities** | **7,844,671** | **8,080,777** | **8,594,053** | **8,913,155** | **8,252,157** |
| **Deferred Credits** | **3,484,113** | **3,340,694** | **3,428,200** | **3,297,425** | **2,937,810** |
| **Total Liabilities and Other Credits** | **103,044,849** | **106,947,439** | **112,309,422** | **114,246,146** | **99,501,839** |

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 222 for 1995, 227 for 1994, 222 for 1993, 225 for 1992, and 218 for 1991.

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, 1991 Through 1995

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| Electric Utility Plant per Dollar of Revenue | 3.9 | 3.9 | 3.9 | 4.0 | 4.0 |
| Current Assets to Current Liabilities | 1.8 | 1.9 | 1.8 | 1.8 | 1.6 |
| Electric Utility Plant as a Percent of Total Assets | 79.1 | 79.8 | 78.7 | 80.6 | 84.5 |
| Net Electric Utility Plant as a Percent of Total Assets | 58.9 | 57.7 | 55.6 | 55.6 | 57.4 |
| Debt as a Percent of Total Liabilities | 74.4 | 74.9 | 75.5 | 75.0 | 72.0 |
| Accumulated Provision for Depreciation as a Percent of Electric Utility Plant | 25.5 | 27.7 | 29.3 | 30.9 | 32.2 |
| Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues | 64.5 | 65.0 | 65.7 | 65.2 | 64.4 |
| Electric Depreciation and Amortization as a Percent of Electric Operating Revenues | 10.9 | 10.5 | 10.8 | 11.1 | 11.8 |
| Taxes and Tax Equivalents as a Percent of Electric Operating Revenues | 2.8 | 3.1 | 3.4 | 3.3 | 3.6 |
| Interest Expenses as a Percent of Electric Operating Revenues | 22.6 | 21.9 | 19.7 | 18.6 | 17.0 |
| Net Income as a Percent of Electric Operating Revenues | 3.6 | 4.5 | 3.0 | 3.9 | 5.0 |
| Purchase Power Cents Per Kilowatthour | 3.8 | 3.7 | 3.6 | 3.6 | 3.3 |
| Generated Cents Per Kilowatthour | 1.8 | 1.9 | 1.9 | 1.9 | 1.6 |
| Total Power Supply Per Kilowatthour Sold | 2.6 | 2.6 | 2.6 | 2.6 | 2.3 |

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 222 for 1995, 227 for 1994, 222 for 1993, 225 for 1992, and 218 for 1991.
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, 1991 Through 1995

(Thousand Dollars)

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Operating Revenue - Electric** | **21,082,870** | **21,686,349** | **22,521,847** | **23,266,686** | **20,784,089** |
| **Operating Expenses - Electric** | **16,886,921** | **17,190,647** | **18,162,164** | **18,648,687** | **16,714,140** |
| Operation Including Fuel | 12,155,075 | 12,527,435 | 13,241,567 | 13,577,615 | 12,021,449 |
| Production | 9,465,070 | 9,712,324 | 10,254,301 | 10,444,534 | 9,399,785 |
| Transmission | 508,711 | 534,512 | 579,635 | 609,612 | 289,108 |
| Distribution | 362,654 | 388,703 | 408,335 | 429,535 | 421,687 |
| Customer Accounts | 289,398 | 299,209 | 314,992 | 316,794 | 321,790 |
| Customer Service | 73,901 | 82,731 | 94,089 | 104,101 | 101,684 |
| Sales | 18,077 | 17,545 | 17,210 | 22,436 | 19,617 |
| Administrative and General | 1,437,265 | 1,492,411 | 1,573,005 | 1,650,603 | 1,467,778 |
| Maintenance | 1,446,295 | 1,564,792 | 1,565,293 | 1,584,444 | 1,362,483 |
| Depreciation and Amortization Excluding Nuclear Fuel | 2,300,532 | 2,285,807 | 2,441,927 | 2,591,423 | 2,445,672 |
| Taxes and Tax Equivalents | 595,719 | 681,140 | 759,205 | 766,068 | 756,144 |
| Net Contributions and Services | 389,300 | — | — | — | — |
| **Income from Electric Utility Operations** | **4,195,949** | **4,495,703** | **4,359,683** | **4,617,999** | **4,069,949** |

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 222 for 1995, 227 for 1994, 222 for 1993, 225 for 1992, and 218 for 1991.
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, 1991 Through 1995

(Thousand Dollars)

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Operating Revenue - Electric** | **7,119,875** | **7,247,407** | **7,523,453** | **7,995,632** | **8,359,797** |
| **Operating Expenses - Electric** | **6,859,619** | **6,843,539** | **7,063,260** | **7,566,745** | **7,913,792** |
| **Operation Excluding Fuel** | 6,119,381 | 6,244,812 | 6,424,783 | 6,857,958 | 7,111,506 |
| Fuel | 4 | 19 | 15 | 13 | 132 |
| Maintenance | 186,267 | 192,635 | 207,046 | 233,967 | 248,823 |
| Depreciation and Amortization[1] | 246,594 | 251,079 | 256,736 | 273,770 | 309,943 |
| Taxes and Tax Equivalents | 138,491 | 154,994 | 174,681 | 201,038 | 243,389 |
| Net Contributions and Services | 168,882 | — | — | — | — |
| **Operating Income - Electric** | **260,255** | **403,868** | **460,193** | **428,887** | **446,005** |
| **Other Income and Deductions** | **138,039** | **74,486** | **98,822** | **97,664** | **141,343** |
| Income from Electric Plant Leased to Others | 3,264 | 1,773 | 2,405 | 2,185 | 4,345 |
| Allowance for Funds Used During Construction | 1,606 | 39 | 106 | 51 | 41 |
| Other Income Net | 147,117 | 172,938 | 172,569 | 178,515 | 214,683 |
| Less Other Electric Deductions | 13,949 | 100,264 | 76,258 | 83,086 | 77,725 |
| **Total Income Before Interest Charges** | **398,294** | **478,354** | **559,015** | **526,551** | **587,348** |
| **Net Interest Charges** | **139,806** | **140,861** | **172,792** | **156,433** | **168,148** |
| Interest Expenses | 112,031 | 109,378 | 114,527 | 108,647 | 126,611 |
| Other Income Deductions | 27,775 | 31,483 | 58,264 | 47,786 | 41,537 |
| **Net Income Before Extraordinary Charges** | **258,488** | **337,493** | **386,223** | **370,118** | **419,200** |
| Less **Extraordinary Items** | **9,252** | **2,156** | **25,600** | **3,821** | **6,659** |
| **Net Income** | **249,236** | **335,338** | **360,624** | **366,297** | **412,541** |

[1] Nuclear fuel included in 1992, 1993, 1994, and 1995 data.

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1995, 275 for 1994, 273 for 1993, 258 for 1992, and 252 for 1991.

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, 1991 Through 1995

(Thousand Dollars)

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| **Electric Utility Plant-Net Inc Nuclear Fuel** | **4,662,421** | **4,881,003** | **5,268,229** | **5,496,059** | **6,235,547** |
| Electric Utility Plant Inc Nuclear Fuel | 7,318,688 | 7,733,037 | 8,317,096 | 8,759,850 | 9,871,870 |
| Accumulated Provision for Depreciation and Amortization | 2,656,267 | 2,852,034 | 3,048,867 | 3,263,791 | 3,636,323 |
| **Other Property and Investments** | **1,849,607** | **1,890,451** | **1,911,724** | **1,904,194** | **2,189,562** |
| **Current and Accrued Assets** | **2,162,131** | **2,227,084** | **2,495,760** | **2,497,816** | **2,862,823** |
| **Deferred Debits** | **324,440** | **386,263** | **423,907** | **400,447** | **490,986** |
| **Total Assets and Other Debits** | **8,998,600** | **9,384,801** | **10,099,620** | **10,298,517** | **11,778,918** |
| **Liabilities and Other Credits** | | | | | |
| **Investment of Municipality - Surplus** | **5,244,951** | **5,522,242** | **5,983,376** | **6,281,647** | **6,901,844** |
| **Long-Term Debt** | **2,542,435** | **2,713,721** | **2,898,817** | **2,723,507** | **3,428,673** |
| **Other Noncurrent Liabilities** | **55,488** | **10,284** | **10,749** | **11,414** | **13,372** |
| **Current and Accrued Liabilities** | **968,924** | **982,587** | **1,039,867** | **1,098,941** | **1,223,871** |
| **Deferred Credits** | **186,803** | **154,689** | **166,812** | **183,009** | **211,158** |
| **Total Liabilities and Other Credits** | **8,998,600** | **9,384,801** | **10,099,620** | **10,298,517** | **11,778,917** |

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1995, 275 for 1994, 273 for 1993, 258 for 1992, and 252 for 1991.

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, 1991 Through 1995

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| Electric Utility Plant per Dollar of Revenue | 1.0 | 1.1 | 1.1 | 1.1 | 1.2 |
| Current Assets to Current Liabilities | 2.2 | 2.3 | 2.4 | 2.3 | 2.3 |
| Electric Utility Plant as a Percent of Total Assets | 81.3 | 82.4 | 82.4 | 85.1 | 83.8 |
| Net Electric Utility Plant as a Percent of Total Assets | 51.8 | 52.0 | 52.2 | 53.4 | 52.9 |
| Debt as a Percent of Total Liabilities | 39.0 | 39.4 | 39.0 | 37.1 | 39.5 |
| Accumulated Provision for Depreciation as a Percent of Electric Utility Plant | 36.3 | 36.9 | 36.7 | 37.3 | 36.8 |
| Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues | 88.6 | 88.8 | 88.1 | 88.7 | 88.0 |
| Electric Depreciation and Amortization as a Percent of Electric Operating Revenues | 3.5 | 3.4 | 3.4 | 3.4 | 3.7 |
| Taxes and Tax Equivalents as a Percent of Electric Operating Revenues | 1.9 | 2.1 | 2.3 | 2.5 | 2.9 |
| Interest Expenses as a Percent of Electric Operating Revenues | 1.6 | 1.5 | 1.5 | 1.4 | 1.5 |
| Net Income as a Percent of Electric Operating Revenues | 3.5 | 4.6 | 4.8 | 4.6 | 4.9 |
| Purchase Power Cents Per Kilowatthour | 4.1 | 4.1 | 4.1 | 4.1 | 4.2 |

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1995, 275 for 1994, 273 for 1993, 258 for 1992, and 252 for 1991.
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, 1991 Through 1995
(Thousand Dollars)

| Description | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Operating Revenue - Electric** | **7,119,875** | **7,247,407** | **7,523,453** | **7,995,632** | **8,359,797** |
| **Operating Expenses - Electric** | **6,859,619** | **6,843,539** | **7,063,260** | **7,566,745** | **7,913,792** |
| Operation Including Fuel | 6,119,385 | 6,244,831 | 6,424,798 | 6,857,970 | 7,111,637 |
| Production | 5,523,601 | 5,617,261 | 5,760,626 | 6,185,035 | 6,357,741 |
| Transmission | 32,264 | 32,956 | 33,755 | 34,045 | 34,581 |
| Distribution | 164,147 | 176,188 | 189,023 | 190,181 | 210,516 |
| Customer Accounts | 102,488 | 109,196 | 117,353 | 119,019 | 124,813 |
| Customer Service | 15,536 | 15,629 | 17,166 | 16,941 | 17,916 |
| Sales | 11,587 | 11,646 | 8,704 | 9,845 | 9,458 |
| Administrative and General | 269,762 | 281,954 | 298,171 | 302,904 | 356,612 |
| Maintenance | 186,267 | 192,635 | 207,046 | 233,967 | 248,823 |
| Depreciation and Amortization Excluding Nuclear Fuel | 246,594 | 248,040 | 252,850 | 268,790 | 307,146 |
| Taxes and Tax Equivalents | 138,491 | 154,994 | 174,681 | 201,038 | 243,389 |
| Net Contributions and Services | 168,882 | — | — | — | — |
| **Income from Electric Utility Operations** | **260,255** | **403,868** | **460,193** | **428,887** | **446,005** |

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1995, 275 for 1994, 273 for 1993, 258 for 1992, and 252 for 1991.
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 $NO_x$ 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 $NO_x$. 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. Additional detailed information on emissions from electric utilities can be obtained in Chapter 6 of the *Annual Energy Outlook*.[12] 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 almost 900 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.

[12] Energy Information Administration, *Annual Energy Outlook* DOE/EIA-0383(94)(Washington, DC, 1994).

## Table 22. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities, 1991 Through 1995

(Thousand Short Tons)

| Emission | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| Sulfur Dioxide (SO2) | 15,513 | 15,175 | 15,014 | 14,377 | 11,571 |
| Nitrogen Oxides (NOx)[1] | 7,433 | 7,188 | 7,378 | 7,168 | 7,135 |
| Carbon Dioxide (CO2)[1] | 1,907,812 | 1,902,884 | 1,970,193 | 1,972,001 | 1,967,669 |

1 As of 1993 data, CO2 emissions from the emission factor for light oil and NOx emissions reductions from control technologies have been revised due to a software problem--(see Technical Notes)--historical data were revised to reflect these changes.

Notes: •Estimates for 1995 are preliminary; estimates for prior years are final. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1996) Air Pollutant Emissions Factors (AP-42 5th release) of the Environmental Protection Agency (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

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

## Table 23. Number and Capacity of Fossil-Fueled Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment, 1991 Through 1995

| Environmental Equipment | Scrubbers | | Particulate Collectors | |
|---|---|---|---|---|
| | Number of Generators | Capacity[1] (megawatts) | Number of Generators | Capacity[1] (megawatts) |
| 1991 | 155 | 70,734 | 1,173 | 352,910 |
| 1992 | 155 | 71,531 | 1,168 | 353,365 |
| 1993 | 154 | 71,106 | 1,151 | 350,808 |
| 1994 | 168 | 80,617 | 1,135 | 351,180 |
| 1995 | 177 | 84,260 | 1,133 | 350,780 |

| | Cooling Towers | | Total[2] | |
|---|---|---|---|---|
| | Number of Generators | Capacity[1] (megawatts) | Number of Generators | Capacity[1] (megawatts) |
| **1991** | 485 | 164,632 | 1,353 | 378,883 |
| **1992** | 484 | 165,030 | 1,345 | 379,034 |
| **1993** | 486 | 164,807 | 1,330 | 376,831 |
| **1994** | 480 | 165,452 | 1,309 | 376,899 |
| **1995** | 471 | 165,012 | 1,295 | 375,408 |

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 1995 are preliminary; 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 24. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Census Division and State, 1994 and 1995

(Thousand Short Tons)

| Census Division State | 1994 | | | 1995 | | |
|---|---|---|---|---|---|---|
| | Sulfur Dioxide | Nitrogen Oxides[1] | Carbon Dioxide[1] | Sulfur Dioxide | Nitrogen Oxides[1] | Carbon Dioxide[1] |
| **New England** | **206** | **78** | **29,573** | **164** | **71** | **31,063** |
| Connecticut | 26 | 10 | 5,702 | 26 | 11 | 6,538 |
| Maine | 5 | 1 | 677 | 4 | 1 | 782 |
| Massachusetts | 125 | 45 | 18,225 | 89 | 47 | 18,917 |
| New Hampshire | 50 | 22 | 4,756 | 45 | 11 | 4,614 |
| Rhode Island | * | * | 67 | — | — | — |
| Vermont | * | * | 146 | * | * | 212 |
| **Middle Atlantic** | **1,429** | **433** | **154,812** | **1,312** | **409** | **151,838** |
| New Jersey | 53 | 39 | 8,563 | 37 | 32 | 7,252 |
| New York | 246 | 115 | 43,948 | 207 | 111 | 43,221 |
| Pennsylvania | 1,129 | 278 | 102,301 | 1,067 | 267 | 101,365 |
| **East North Central** | **4,603** | **1,819** | **414,984** | **3,248** | **1,785** | **418,708** |
| Illinois | 802 | 352 | 70,626 | 624 | 353 | 71,395 |
| Indiana | 1,236 | 486 | 112,341 | 900 | 501 | 114,544 |
| Michigan | 397 | 317 | 71,336 | 368 | 266 | 69,004 |
| Ohio | 1,980 | 498 | 120,862 | 1,172 | 493 | 122,046 |
| Wisconsin | 190 | 166 | 39,818 | 183 | 172 | 41,718 |
| **West North Central** | **1,085** | **876** | **202,293** | **841** | **921** | **212,475** |
| Iowa | 172 | 142 | 30,935 | 169 | 147 | 33,386 |
| Kansas | 71 | 138 | 31,761 | 71 | 129 | 31,574 |
| Minnesota | 88 | 151 | 34,216 | 81 | 150 | 34,577 |
| Missouri | 521 | 249 | 52,957 | 303 | 297 | 59,139 |
| Nebraska | 54 | 79 | 16,034 | 61 | 89 | 18,188 |
| North Dakota | 145 | 98 | 32,909 | 129 | 94 | 32,283 |
| South Dakota | 33 | 17 | 3,480 | 28 | 15 | 3,328 |
| **South Atlantic** | **3,350** | **1,206** | **377,903** | **2,805** | **1,210** | **376,073** |
| Delaware | 44 | 20 | 6,989 | 42 | 18 | 6,134 |
| District of Columbia | 2 | * | 283 | 1 | * | 189 |
| Florida | 708 | 314 | 95,466 | 572 | 330 | 94,039 |
| Georgia | 553 | 169 | 64,303 | 452 | 187 | 69,335 |
| Maryland | 250 | 90 | 29,631 | 214 | 83 | 28,872 |
| North Carolina | 362 | 179 | 52,180 | 340 | 171 | 54,275 |
| South Carolina | 190 | 88 | 27,501 | 204 | 82 | 26,518 |
| Virginia | 174 | 73 | 24,323 | 188 | 77 | 25,614 |
| West Virginia | 1,066 | 272 | 77,227 | 791 | 263 | 71,097 |
| **East South Central** | **2,289** | **764** | **212,500** | **1,837** | **845** | **227,655** |
| Alabama | 512 | 199 | 63,619 | 488 | 228 | 69,625 |
| Kentucky | 897 | 330 | 82,664 | 777 | 332 | 85,677 |
| Mississippi | 92 | 47 | 13,806 | 78 | 77 | 14,425 |
| Tennessee | 788 | 188 | 52,412 | 494 | 208 | 57,928 |
| **West South Central** | **827** | **1,034** | **297,987** | **831** | **1,053** | **303,848** |
| Arkansas | 68 | 74 | 23,618 | 74 | 83 | 26,063 |
| Louisiana | 194 | 153 | 39,574 | 171 | 163 | 42,568 |
| Oklahoma | 92 | 142 | 38,459 | 109 | 149 | 40,844 |
| Texas | 473 | 664 | 196,336 | 477 | 658 | 194,373 |
| **Mountain** | **482** | **796** | **225,541** | **461** | **736** | **209,909** |
| Arizona | 138 | 130 | 41,254 | 123 | 110 | 34,880 |
| Colorado | 93 | 143 | 34,509 | 96 | 131 | 33,278 |
| Idaho | — | — | — | — | — | — |
| Montana | 21 | 59 | 18,876 | 20 | 52 | 16,840 |
| Nevada | 53 | 68 | 20,363 | 51 | 62 | 18,899 |
| New Mexico | 63 | 121 | 30,584 | 59 | 119 | 30,444 |
| Utah | 29 | 103 | 33,367 | 28 | 95 | 31,648 |
| Wyoming | 85 | 173 | 46,587 | 84 | 166 | 43,921 |
| **Pacific Contiguous** | **86** | **151** | **51,383** | **52** | **92** | **30,926** |
| California | 4 | 90 | 36,097 | 1 | 56 | 22,126 |
| Oregon | 14 | 17 | 4,084 | 5 | 7 | 1,734 |
| Washington | 67 | 44 | 11,202 | 46 | 29 | 7,066 |
| **Pacific Noncontiguous** | **20** | **13** | **5,027** | **21** | **13** | **5,175** |
| Alaska | 1 | 3 | 464 | 1 | 3 | 495 |
| Hawaii | 19 | 10 | 4,563 | 20 | 10 | 4,681 |
| **U.S. Total** | **14,377** | **7,168** | **1,972,001** | **11,571** | **7,135** | **1,967,669** |

1 As of 1993 data, CO2 emissions from the emission factor for light oil and NOx emissions reductions from control technologies have been revised due to a software problem--(see Technical Notes)--historical data were revised to reflect these changes.

* =Value less than 0.5.

Notes: •Estimates for 1995 are preliminary; estimates for prior years are final. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1996) Air Pollutant Emissions Factors (AP-42 5th release) of the Environmental Protection Agency (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

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

## Table 25. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Fossil Fuel, Census Division, and State, 1995

(Thousand Short Tons)

| Census Division State | Coal | | | Petroleum | | | Gas | | | Other[1] | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Sulfur Dioxide | Nitrogen Oxides[2] | Carbon Dioxide[2] | Sulfur Dioxide | Nitrogen Oxides[2] | Carbon Dioxide[2] | Sulfur Dioxide | Nitrogen Oxides[2] | Carbon Dioxide[2] | Sulfur Dioxide | Nitrogen Oxides[2] | Carbon Dioxide[2] |
| **New England** | **101** | **41** | **16,235** | **63** | **16** | **9,822** | * | **15** | **4,758** | * | * | **249** |
| Connecticut | 9 | 5 | 2,329 | 16 | 4 | 3,053 | * | 2 | 1,142 | * | * | 15 |
| Maine | 0 | 0 | 0 | 4 | 1 | 782 | 0 | 0 | 0 | 0 | 0 | 0 |
| Massachusetts | 55 | 25 | 10,406 | 34 | 9 | 5,023 | * | 12 | 3,475 | * | * | 13 |
| New Hampshire | 36 | 10 | 3,500 | 9 | 1 | 963 | * | * | 134 | * | * | 17 |
| Rhode Island | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vermont | 0 | 0 | 0 | * | * | 1 | 0 | * | 8 | * | * | 203 |
| **Middle Atlantic** | **1,270** | **349** | **123,988** | **41** | **18** | **11,129** | * | **42** | **16,687** | * | * | **33** |
| New Jersey | 35 | 26 | 5,540 | 2 | 2 | 732 | * | 4 | 979 | * | * | 1 |
| New York | 177 | 62 | 20,727 | 30 | 13 | 8,076 | * | 35 | 14,418 | 0 | 0 | 0 |
| Pennsylvania | 1,058 | 260 | 97,721 | 9 | 4 | 2,322 | * | 3 | 1,291 | * | * | 32 |
| **East North Central** | **3,241** | **1,771** | **413,203** | **6** | **3** | **1,830** | * | **11** | **3,404** | * | * | **271** |
| Illinois | 622 | 344 | 68,262 | 2 | 1 | 749 | * | 8 | 2,384 | 0 | 0 | 1 |
| Indiana | 900 | 500 | 114,023 | * | * | 144 | * | 1 | 377 | 0 | 0 | 0 |
| Michigan | 365 | 264 | 67,951 | 4 | 1 | 731 | * | 1 | 323 | 0 | * | * |
| Ohio | 1,172 | 493 | 121,709 | * | * | 184 | * | * | 154 | 0 | 0 | 0 |
| Wisconsin | 182 | 171 | 41,258 | * | * | 23 | * | 1 | 166 | * | * | 271 |
| **West North Central** | **840** | **908** | **208,416** | **1** | * | **199** | * | **11** | **2,733** | **1** | **1** | **1,127** |
| Iowa | 168 | 147 | 33,123 | * | * | 25 | * | 1 | 158 | * | * | 80 |
| Kansas | 71 | 122 | 30,124 | * | * | 38 | * | 6 | 1,413 | 0 | 0 | 0 |
| Minnesota | 80 | 147 | 33,102 | * | * | 19 | * | 2 | 467 | 1 | 1 | 988 |
| Missouri | 303 | 296 | 58,503 | * | * | 65 | * | 2 | 570 | 0 | * | * |
| Nebraska | 61 | 88 | 18,063 | * | * | 6 | * | * | 117 | 0 | * | 2 |
| North Dakota | 129 | 94 | 32,239 | * | * | 44 | 0 | 0 | * | 0 | 0 | 0 |
| South Dakota | 28 | 15 | 3,262 | * | * | 2 | 0 | * | 8 | * | * | 56 |
| **South Atlantic** | **2,617** | **1,112** | **339,196** | **187** | **44** | **21,932** | * | **54** | **14,800** | * | * | **144** |
| Delaware | 37 | 14 | 4,745 | 4 | 1 | 789 | * | 2 | 596 | * | * | 4 |
| District of Columbia | 0 | 0 | 0 | 1 | * | 189 | 0 | 0 | 0 | 0 | 0 | 0 |
| Florida | 406 | 243 | 62,587 | 166 | 38 | 18,412 | * | 49 | 12,936 | * | * | 103 |
| Georgia | 451 | 186 | 69,017 | 1 | * | 106 | * | * | 178 | * | * | 34 |
| Maryland | 205 | 79 | 26,978 | 9 | 2 | 1,198 | * | 2 | 693 | * | * | 3 |
| North Carolina | 340 | 171 | 54,163 | * | * | 112 | 0 | 0 | 0 | 0 | 0 | 0 |
| South Carolina | 204 | 81 | 26,140 | * | * | 82 | * | 1 | 295 | * | * | 1 |
| Virginia | 182 | 75 | 24,626 | 5 | 1 | 911 | 0 | * | 76 | 0 | 0 | 0 |
| West Virginia | 791 | 263 | 70,939 | * | * | 133 | 0 | * | 25 | 0 | 0 | 0 |
| **East South Central** | **1,837** | **825** | **222,330** | **1** | * | **284** | * | **20** | **5,030** | * | * | **10** |
| Alabama | 488 | 228 | 69,375 | * | * | 84 | * | 1 | 166 | 0 | 0 | 0 |
| Kentucky | 777 | 332 | 85,547 | * | * | 104 | 0 | * | 25 | 0 | * | * |
| Mississippi | 78 | 58 | 9,565 | * | * | 12 | * | 19 | 4,838 | * | * | 10 |
| Tennessee | 494 | 208 | 57,843 | * | * | 85 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West South Central** | **830** | **744** | **215,156** | **1** | * | **353** | * | **309** | **88,339** | **0** | **0** | * |
| Arkansas | 74 | 77 | 24,053 | * | * | 41 | * | 6 | 1,969 | 0 | 0 | 0 |
| Louisiana | 171 | 96 | 23,297 | * | * | 44 | * | 67 | 19,227 | 0 | 0 | 0 |
| Oklahoma | 109 | 119 | 32,761 | * | * | 58 | * | 30 | 8,025 | 0 | 0 | 0 |
| Texas | 477 | 453 | 135,044 | * | * | 209 | * | 205 | 59,119 | 0 | 0 | * |
| **Mountain** | **460** | **720** | **205,182** | * | * | **243** | * | **16** | **4,484** | **0** | * | * |
| Arizona | 123 | 108 | 34,213 | * | * | 54 | * | 2 | 613 | 0 | 0 | 0 |
| Colorado | 96 | 130 | 32,991 | * | * | 43 | * | 1 | 244 | 0 | * | * |
| Idaho | – | – | – | – | – | – | – | – | – | – | – | – |
| Montana | 20 | 52 | 16,817 | * | * | 15 | 0 | * | 7 | 0 | 0 | 0 |
| Nevada | 51 | 56 | 17,419 | * | * | 23 | * | 6 | 1,456 | 0 | 0 | 0 |
| New Mexico | 59 | 114 | 28,692 | * | * | 19 | * | 5 | 1,732 | 0 | 0 | 0 |
| Utah | 28 | 94 | 31,196 | * | * | 28 | * | 1 | 423 | 0 | 0 | 0 |
| Wyoming | 84 | 166 | 43,853 | * | * | 60 | 0 | * | 8 | 0 | 0 | 0 |
| **Pacific Contiguous** | **50** | **36** | **8,329** | **1** | **1** | **403** | * | **55** | **21,734** | * | * | **461** |
| California | 0 | 0 | 0 | 1 | 1 | 392 | * | 55 | 21,733 | 0 | 0 | 0 |
| Oregon | 5 | 7 | 1,730 | * | * | 4 | 0 | 0 | 0 | 0 | 0 | 0 |
| Washington | 46 | 29 | 6,599 | * | * | 7 | 0 | * | * | * | * | 461 |
| **Pacific Noncontiguous** | **1** | **3** | **493** | **20** | **10** | **4,683** | **0** | **0** | **0** | **0** | **0** | **0** |
| Alaska | 1 | 3 | 493 | * | * | 2 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hawaii | 0 | 0 | 0 | 20 | 10 | 4,681 | 0 | 0 | 0 | 0 | 0 | 0 |
| **U.S. Total** | **11,248** | **6,508** | **1,752,527** | **321** | **92** | **50,878** | **1** | **533** | **161,969** | **2** | **2** | **2,295** |

1 Includes light oil, methane, coal/oil mixture, propane gas, blast furnace gas, wood, and refuse.

2 As of 1993 data, CO2 emissions from the emission factor for light oil and NOx emissions reductions from control technologies have been revised due to a software problem--(see Technical Notes)--historical data were revised to reflect these changes.

Notes: •Estimates for 1995 are preliminary. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1996) Air Pollutant Emissions Factors (AP-42 5th release) of the Environmental Protection Agency (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data. •*=Value less than 0.5.

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

## Table 26. Number and Capacity of Coal-Fired Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment by Census Division and State, 1995

| 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** | **15** | **2,773** | **0** | **0** | **15** | **2,773** | **0** | **0** |
| Connecticut | 1 | 400 | 0 | 0 | 1 | 400 | 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 | — | — | — | — | — | — | — | — |
| Vermont | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Middle Atlantic** | **84** | **24,205** | **14** | **7,048** | **83** | **24,070** | **17** | **11,501** |
| New Jersey | 7 | 1,820 | 1 | 163 | 6 | 1,685 | 1 | 135 |
| New York | 25 | 3,721 | 3 | 978 | 25 | 3,721 | 0 | 0 |
| Pennsylvania | 52 | 18,664 | 10 | 5,907 | 52 | 18,664 | 16 | 11,366 |
| **East North Central** | **294** | **81,225** | **24** | **11,885** | **294** | **81,225** | **41** | **20,489** |
| Illinois | 55 | 17,123 | 4 | 1,439 | 55 | 17,123 | 2 | 562 |
| Indiana | 68 | 21,207 | 12 | 5,240 | 68 | 21,207 | 23 | 9,395 |
| Michigan | 49 | 12,124 | 0 | 0 | 49 | 12,124 | 2 | 199 |
| Ohio | 83 | 23,729 | 6 | 5,046 | 83 | 23,729 | 11 | 8,854 |
| Wisconsin | 39 | 7,041 | 2 | 160 | 39 | 7,041 | 3 | 1,479 |
| **West North Central** | **138** | **35,748** | **24** | **10,692** | **138** | **35,748** | **38** | **11,770** |
| Iowa | 29 | 5,691 | 1 | 176 | 29 | 5,691 | 6 | 1,681 |
| Kansas | 19 | 5,634 | 7 | 3,920 | 19 | 5,634 | 8 | 3,258 |
| Minnesota | 25 | 5,417 | 8 | 3,333 | 25 | 5,417 | 9 | 3,787 |
| Missouri | 38 | 11,448 | 2 | 455 | 38 | 11,448 | 7 | 789 |
| Nebraska | 14 | 3,092 | 0 | 0 | 14 | 3,092 | 4 | 430 |
| North Dakota | 12 | 4,009 | 6 | 2,809 | 12 | 4,009 | 4 | 1,826 |
| South Dakota | 1 | 456 | 0 | 0 | 1 | 456 | 0 | 0 |
| **South Atlantic** | **214** | **69,731** | **20** | **10,682** | **214** | **69,731** | **63** | **36,342** |
| Delaware | 6 | 1,034 | 0 | 0 | 6 | 1,034 | 1 | 442 |
| District of Columbia | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Florida | 27 | 10,877 | 7 | 4,102 | 27 | 10,877 | 11 | 6,293 |
| Georgia | 38 | 14,537 | 1 | 123 | 38 | 14,537 | 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 | 25 | 5,915 | 5 | 2,092 | 25 | 5,915 | 14 | 4,378 |
| Virginia | 25 | 4,973 | 1 | 424 | 25 | 4,973 | 4 | 1,137 |
| West Virginia | 33 | 14,958 | 6 | 3,942 | 33 | 14,958 | 13 | 9,822 |
| **East South Central** | **132** | **40,471** | **29** | **12,295** | **132** | **40,471** | **28** | **12,893** |
| Alabama | 39 | 12,586 | 4 | 1,597 | 39 | 12,586 | 4 | 2,599 |
| Kentucky | 54 | 15,956 | 21 | 7,698 | 54 | 15,956 | 21 | 9,394 |
| Mississippi | 6 | 2,150 | 2 | 400 | 6 | 2,150 | 3 | 900 |
| Tennessee | 33 | 9,780 | 2 | 2,600 | 33 | 9,780 | 0 | 0 |
| **West South Central** | **59** | **33,690** | **16** | **10,547** | **59** | **33,690** | **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 | 20,724 | 14 | 9,306 | 36 | 20,724 | 14 | 7,109 |
| **Mountain** | **88** | **30,539** | **50** | **21,112** | **88** | **30,539** | **76** | **26,044** |
| Arizona | 14 | 5,749 | 9 | 2,877 | 14 | 5,749 | 12 | 5,347 |
| Colorado | 26 | 4,976 | 5 | 1,974 | 26 | 4,976 | 24 | 4,524 |
| Idaho | — | — | — | — | — | — | — | — |
| Montana | 5 | 2,464 | 4 | 2,273 | 5 | 2,464 | 4 | 2,273 |
| Nevada | 8 | 2,769 | 5 | 879 | 8 | 2,769 | 7 | 1,951 |
| New Mexico | 10 | 4,282 | 10 | 4,282 | 10 | 4,282 | 5 | 2,012 |
| Utah | 10 | 4,461 | 7 | 3,826 | 10 | 4,461 | 10 | 4,461 |
| Wyoming | 15 | 5,838 | 10 | 5,001 | 15 | 5,838 | 14 | 5,476 |
| **Pacific Contiguous** | **5** | **2,084** | **0** | **0** | **3** | **2,020** | **4** | **1,524** |
| California | 2 | 64 | 0 | 0 | 0 | 0 | 2 | 64 |
| Oregon | 1 | 561 | 0 | 0 | 1 | 561 | 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** | **1,029** | **320,467** | **177** | **84,260** | **1,026** | **320,268** | **299** | **137,825** |

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: •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. •Data are preliminary.

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

## Table 27. 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, 1995

| 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** | **22** | **6,204** | **0** | **0** | **21** | **5,789** | **1** | **415** |
| Connecticut | 11 | 2,098 | 0 | 0 | 10 | 1,683 | 1 | 415 |
| Maine | 4 | 846 | 0 | 0 | 4 | 846 | 0 | 0 |
| Massachusetts | 6 | 2,846 | 0 | 0 | 6 | 2,846 | 0 | 0 |
| New Hampshire | 1 | 414 | 0 | 0 | 1 | 414 | 0 | 0 |
| Rhode Island | — | — | — | — | — | — | — | — |
| Vermont | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Middle Atlantic** | **36** | **11,052** | **0** | **0** | **34** | **9,351** | **3** | **1,877** |
| New Jersey | 7 | 952 | 0 | 0 | 7 | 952 | 1 | 176 |
| New York | 19 | 6,735 | 0 | 0 | 19 | 6,735 | 0 | 0 |
| Pennsylvania | 10 | 3,365 | 0 | 0 | 8 | 1,664 | 2 | 1,701 |
| **East North Central** | **10** | **2,158** | **0** | **0** | **5** | **625** | **5** | **1,533** |
| Illinois | 1 | 210 | 0 | 0 | 0 | 0 | 1 | 210 |
| Indiana | 2 | 92 | 0 | 0 | 0 | 0 | 2 | 92 |
| Michigan | 6 | 1,743 | 0 | 0 | 4 | 512 | 2 | 1,231 |
| Ohio | 1 | 114 | 0 | 0 | 1 | 114 | 0 | 0 |
| Wisconsin | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West North Central** | **15** | **1,416** | **0** | **0** | **2** | **100** | **13** | **1,315** |
| Iowa | 1 | 19 | 0 | 0 | 1 | 19 | 0 | 0 |
| Kansas | 10 | 1,255 | 0 | 0 | 0 | 0 | 10 | 1,255 |
| Minnesota | 1 | 82 | 0 | 0 | 1 | 82 | 0 | 0 |
| Missouri | 3 | 61 | 0 | 0 | 0 | 0 | 3 | 61 |
| Nebraska | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| North Dakota | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| South Dakota | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **South Atlantic** | **47** | **15,186** | **0** | **0** | **34** | **11,937** | **17** | **4,425** |
| Delaware | 4 | 597 | 0 | 0 | 4 | 597 | 2 | 132 |
| District of Columbia | 2 | 580 | 0 | 0 | 0 | 0 | 2 | 580 |
| Florida | 31 | 9,975 | 0 | 0 | 22 | 8,625 | 9 | 1,351 |
| Georgia | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maryland | 6 | 2,131 | 0 | 0 | 4 | 813 | 3 | 1,480 |
| North Carolina | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| South Carolina | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Virginia | 4 | 1,902 | 0 | 0 | 4 | 1,902 | 1 | 882 |
| West Virginia | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **East South Central** | **4** | **353** | **0** | **0** | **1** | **147** | **3** | **206** |
| Alabama | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Kentucky | 1 | 147 | 0 | 0 | 1 | 147 | 0 | 0 |
| Mississippi | 3 | 206 | 0 | 0 | 0 | 0 | 3 | 206 |
| Tennessee | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West South Central** | **80** | **13,082** | **0** | **0** | **4** | **2,258** | **78** | **11,924** |
| Arkansas | 2 | 183 | 0 | 0 | 0 | 0 | 2 | 183 |
| Louisiana | 12 | 2,308 | 0 | 0 | 2 | 1,184 | 11 | 1,716 |
| Oklahoma | 19 | 4,350 | 0 | 0 | 1 | 567 | 18 | 3,783 |
| Texas | 47 | 6,241 | 0 | 0 | 1 | 507 | 47 | 6,241 |
| **Mountain** | **29** | **2,597** | **0** | **0** | **2** | **101** | **29** | **2,597** |
| Arizona | 13 | 1,382 | 0 | 0 | 0 | 0 | 13 | 1,382 |
| Colorado | 3 | 111 | 0 | 0 | 2 | 101 | 3 | 111 |
| Idaho | — | — | — | — | — | — | — | — |
| Montana | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nevada | 1 | 53 | 0 | 0 | 0 | 0 | 1 | 53 |
| New Mexico | 9 | 800 | 0 | 0 | 0 | 0 | 9 | 800 |
| Utah | 3 | 252 | 0 | 0 | 0 | 0 | 3 | 252 |
| Wyoming | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Pacific Contiguous** | **23** | **2,895** | **0** | **0** | **4** | **205** | **23** | **2,895** |
| California | 23 | 2,895 | 0 | 0 | 4 | 205 | 23 | 2,895 |
| Oregon | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Washington | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **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** | **266** | **54,942** | **0** | **0** | **107** | **30,513** | **172** | **27,187** |

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: •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. •Data are preliminary.

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

## Table 28. Average Quality of Fossil Fuels Burned at U.S. Electric Utilities by Census Division and State, 1994 and 1995

| Census Division State | Coal | | | | | | Petroleum | | | | Gas | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1994 | | | 1995 | | | 1994 | | 1995 | | 1994 | 1995 |
| | 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 | Average Btu per Gallon |
| **New England** | **12,821** | **1.02** | **7.5** | **12,742** | **0.85** | **7.3** | **150,611** | **1.31** | **151,271** | **1.02** | **1,031** | **1,023** |
| Connecticut | 12,974 | .54 | 7.4 | 13,080 | .56 | 7.0 | 151,066 | .90 | 151,656 | .85 | 1,018 | 1,016 |
| Maine | — | — | — | — | — | — | 150,257 | 1.11 | 150,860 | .76 | — | — |
| Massachusetts | 12,737 | .95 | 7.8 | 12,599 | .72 | 7.7 | 150,175 | 1.48 | 150,942 | 1.07 | 1,035 | 1,025 |
| New Hampshire | 12,973 | 1.54 | 6.5 | 12,953 | 1.43 | 6.6 | 151,801 | 1.59 | 152,111 | 1.49 | 1,013 | 1,017 |
| Rhode Island | — | — | — | — | — | — | — | — | — | — | — | — |
| Vermont | — | — | — | — | — | — | 140,000 | .30 | 137,900 | .18 | 1,000 | 998 |
| **Middle Atlantic** | **12,495** | **1.97** | **11.0** | **12,244** | **1.97** | **11.2** | **148,813** | **.64** | **149,386** | **.59** | **1,032** | **1,027** |
| New Jersey | 13,175 | 1.32 | 7.9 | 13,201 | 1.30 | 8.0 | 148,410 | .47 | 148,338 | .45 | 1,036 | 1,031 |
| New York | 12,876 | 1.69 | 8.1 | 12,888 | 1.74 | 8.2 | 149,305 | .65 | 149,512 | .59 | 1,031 | 1,027 |
| Pennsylvania | 12,379 | 2.07 | 11.8 | 12,065 | 2.05 | 12.0 | 147,684 | .65 | 149,280 | .62 | 1,032 | 1,030 |
| **East North Central** | **10,758** | **1.59** | **8.5** | **10,646** | **1.33** | **8.2** | **145,806** | **.72** | **144,648** | **.53** | **1,018** | **1,018** |
| Illinois | 10,082 | 1.50 | 7.5 | 9,899 | 1.18 | 7.1 | 149,147 | .84 | 147,812 | .46 | 1,018 | 1,018 |
| Indiana | 10,450 | 1.82 | 8.3 | 10,325 | 1.60 | 7.8 | 137,422 | .33 | 137,673 | .33 | 1,018 | 1,018 |
| Michigan | 10,821 | .69 | 7.1 | 10,603 | .64 | 6.9 | 145,424 | .78 | 145,048 | .73 | 1,020 | 1,018 |
| Ohio | 11,992 | 2.42 | 11.0 | 12,085 | 1.93 | 11.0 | 137,677 | .28 | 137,672 | .28 | 1,027 | 1,025 |
| Wisconsin | 9,503 | .51 | 6.3 | 9,331 | .47 | 6.1 | 139,615 | .41 | 139,834 | .32 | 1,008 | 1,006 |
| **West North Central** | **8,368** | **.70** | **6.9** | **8,351** | **.56** | **6.5** | **141,714** | **.79** | **140,860** | **.57** | **983** | **992** |
| Iowa | 8,704 | .56 | 5.7 | 8,672 | .51 | 5.8 | 137,853 | .43 | 137,468 | .36 | 1,007 | 1,006 |
| Kansas | 8,538 | .47 | 5.7 | 8,702 | .45 | 5.6 | 140,429 | .40 | 138,252 | .29 | 974 | 980 |
| Minnesota | 8,772 | .53 | 6.7 | 8,803 | .51 | 6.7 | 138,682 | .31 | 139,018 | .33 | 1,005 | 1,007 |
| Missouri | 9,564 | 1.11 | 6.5 | 9,071 | .59 | 5.5 | 145,393 | 1.34 | 145,350 | 1.03 | 999 | 1,004 |
| Nebraska | 8,500 | .35 | 5.2 | 8,532 | .35 | 5.3 | 139,313 | .26 | 138,945 | .25 | 986 | 993 |
| North Dakota | 6,527 | .75 | 9.8 | 6,579 | .73 | 9.3 | 139,070 | .46 | 139,978 | .44 | 1,063 | 1,074 |
| South Dakota | 6,230 | .86 | 8.4 | 6,901 | .83 | 8.1 | 139,167 | .38 | 139,020 | .33 | 1,005 | 1,003 |
| **South Atlantic** | **12,267** | **1.34** | **9.8** | **12,074** | **1.26** | **9.7** | **150,891** | **1.38** | **151,287** | **1.35** | **1,017** | **1,014** |
| Delaware | 12,843 | .93 | 9.1 | 12,830 | 1.09 | 8.5 | 150,018 | .91 | 151,116 | .84 | 1,037 | 1,035 |
| District of Columbia | — | — | — | — | — | — | 143,642 | .91 | 143,291 | .87 | — | — |
| Florida | 12,184 | 1.58 | 8.2 | 12,187 | 1.47 | 8.1 | 151,315 | 1.45 | 151,778 | 1.43 | 1,014 | 1,011 |
| Georgia | 11,551 | 1.09 | 9.0 | 11,544 | .82 | 8.9 | 141,491 | .87 | 144,591 | 1.61 | 1,024 | 1,024 |
| Maryland | 12,753 | 1.18 | 10.2 | 12,944 | 1.06 | 9.6 | 150,352 | 1.42 | 150,999 | 1.18 | 1,043 | 1,039 |
| North Carolina | 12,417 | .92 | 10.3 | 12,430 | .84 | 10.2 | 139,075 | .20 | 138,942 | .20 | — | — |
| South Carolina | 12,685 | 1.20 | 9.0 | 12,763 | 1.19 | 8.6 | 141,333 | .57 | 137,961 | .26 | 1,023 | 1,024 |
| Virginia | 12,767 | .98 | 9.8 | 12,728 | 1.02 | 10.1 | 150,843 | 1.11 | 149,880 | .92 | 1,010 | 1,039 |
| West Virginia | 12,394 | 1.89 | 11.7 | 11,463 | 1.98 | 12.0 | 139,398 | .33 | 139,004 | .33 | 1,015 | 1,000 |
| **East South Central** | **11,920** | **1.80** | **10.3** | **11,863** | **1.74** | **9.9** | **149,032** | **2.12** | **138,669** | **.30** | **1,027** | **1,032** |
| Alabama | 12,041 | 1.35 | 11.6 | 11,773 | 1.18 | 10.8 | 137,587 | .25 | 138,253 | .29 | 1,012 | 1,022 |
| Kentucky | 11,746 | 2.14 | 10.2 | 11,817 | 2.13 | 10.2 | 138,735 | .27 | 138,949 | .26 | 1,019 | 1,022 |
| Mississippi | 11,349 | 1.07 | 7.9 | 11,151 | 1.05 | 7.9 | 152,882 | 2.78 | 141,391 | .86 | 1,028 | 1,032 |
| Tennessee | 12,164 | 1.95 | 9.4 | 12,173 | 1.98 | 8.8 | 138,262 | .26 | 138,365 | .28 | — | — |
| **West South Central** | **7,616** | **.63** | **9.6** | **7,626** | **.66** | **9.7** | **144,410** | **.45** | **139,326** | **.47** | **1,028** | **1,029** |
| Arkansas | 8,549 | .32 | 4.9 | 8,545 | .31 | 4.9 | 141,806 | .54 | 138,111 | .65 | 1,024 | 1,023 |
| Louisiana | 7,899 | .56 | 7.4 | 7,888 | .64 | 7.8 | 149,091 | .47 | 138,829 | .41 | 1,043 | 1,044 |
| Oklahoma | 8,555 | .35 | 5.1 | 8,544 | .38 | 5.3 | 138,518 | .36 | 141,980 | .91 | 1,034 | 1,038 |
| Texas | 7,265 | .74 | 11.4 | 7,258 | .77 | 11.6 | 142,359 | .42 | 138,927 | .33 | 1,023 | 1,023 |
| **Mountain** | **9,812** | **.55** | **11.2** | **9,794** | **.55** | **11.2** | **144,850** | **.57** | **139,312** | **.29** | **1,027** | **1,026** |
| Arizona | 10,323 | .51 | 12.0 | 10,325 | .53 | 12.1 | 146,526 | .70 | 140,279 | .34 | 1,023 | 1,023 |
| Colorado | 10,030 | .41 | 7.2 | 9,869 | .40 | 7.1 | 136,086 | .19 | 138,253 | .33 | 982 | 986 |
| Idaho | — | — | — | — | — | — | — | — | — | — | — | — |
| Montana | 8,480 | .66 | 9.1 | 8,487 | .68 | 9.3 | 141,000 | .50 | 141,000 | .50 | 1,055 | 1,073 |
| Nevada | 11,786 | .48 | 9.6 | 11,934 | .48 | 9.7 | 148,511 | .69 | 144,160 | .49 | 1,035 | 1,030 |
| New Mexico | 9,056 | .82 | 22.5 | 9,154 | .77 | 21.6 | 136,000 | .10 | 134,785 | .10 | 1,023 | 1,021 |
| Utah | 11,588 | .48 | 10.6 | 11,622 | .48 | 10.6 | 138,745 | .34 | 138,168 | .21 | 1,044 | 1,055 |
| Wyoming | 8,711 | .54 | 8.1 | 8,664 | .51 | 8.2 | 139,213 | .30 | 139,052 | .18 | 1,034 | 1,043 |
| **Pacific Contiguous** | **8,520** | **.57** | **12.0** | **8,218** | **.59** | **11.6** | **145,585** | **.42** | **146,891** | **.50** | **1,026** | **1,025** |
| California | — | — | — | — | — | — | 145,627 | .42 | 147,127 | .51 | 1,026 | 1,025 |
| Oregon | 8,808 | .37 | 5.8 | 8,831 | .29 | 5.4 | 138,800 | .50 | 138,800 | .50 | — | — |
| Washington | 8,416 | .64 | 14.2 | 8,074 | .66 | 13.1 | 140,000 | .30 | 139,900 | .12 | 1,035 | 1,036 |
| **Pacific Noncontiguous** | **7,784** | **.17** | **9.2** | **7,759** | **.18** | **10.0** | **149,809** | **.66** | **148,994** | **.69** | **—** | **—** |
| Alaska | 7,784 | .17 | 9.2 | 7,759 | .18 | 10.0 | 134,356 | .23 | 137,600 | .29 | — | — |
| Hawaii | — | — | — | — | — | — | 149,814 | .67 | 148,999 | .69 | — | — |
| **U.S. Average** | **10,265** | **1.17** | **9.4** | **10,203** | **1.08** | **9.2** | **149,882** | **1.12** | **150,088** | **1.00** | **1,027** | **1,026** |

Notes: •Data for 1995 are preliminary; data for prior years 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 29. Average Flue Gas Desulfurization Costs at U.S. Electric Utilities by Census Division and State, 1991 Through 1995

| Census Division State | Average O&M Costs (mills per kilowatthour) | | | | | Average Installed Costs (dollars per kilowatt) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1991 | 1992 | 1993 | 1994 | 1995 | 1991 | 1992 | 1993 | 1994 | 1995 |
| **New England** | — | — | — | — | — | — | — | — | — | — |
| Connecticut | — | — | — | — | — | — | — | — | — | — |
| Maine | — | — | — | — | — | — | — | — | — | — |
| Massachusetts | — | — | — | — | — | — | — | — | — | — |
| New Hampshire | — | — | — | — | — | — | — | — | — | — |
| Rhode Island | — | — | — | — | — | — | — | — | — | — |
| Vermont | — | — | — | — | — | — | — | — | — | — |
| **Middle Atlantic** | **5.01** | **4.91** | **3.96** | **2.68** | **3.02** | **178** | **183** | **184** | **184** | **184** |
| New Jersey | — | NM | NM | NM | 3.36 | — | 398 | 398 | 398 | 398 |
| New York | 1.07 | 1.03 | 1.09 | 1.03 | 1.18 | 319 | 319 | 331 | 331 | 331 |
| Pennsylvania | 6.20 | 6.04 | 4.65 | 2.96 | 3.40 | 149 | 157 | 157 | 157 | 158 |
| **East North Central** | **2.16** | **1.83** | **1.90** | **2.05** | **1.79** | **139** | **147** | **130** | **127** | **128** |
| Illinois | 2.53 | 2.47 | 2.52 | 2.71 | 2.51 | 197 | 197 | 147 | 147 | 147 |
| Indiana | 2.12 | 1.58 | 1.58 | 1.53 | 1.52 | 133 | 149 | 143 | 142 | 144 |
| Michigan | — | — | — | — | — | — | — | — | — | — |
| Ohio | 2.03 | 2.06 | 2.25 | 2.92 | 1.93 | 83 | 83 | 83 | 88 | 88 |
| Wisconsin | — | — | — | 2.86 | 2.08 | — | — | — | 16 | 16 |
| **West North Central** | **.72** | **.75** | **.66** | **.60** | **.58** | **75** | **83** | **84** | **84** | **78** |
| Iowa | 2.83 | 2.42 | 1.87 | 1.53 | 1.56 | 202 | 202 | 202 | 202 | 202 |
| Kansas | .53 | .66 | .49 | .46 | .49 | 71 | 72 | 72 | 73 | 61 |
| Minnesota | .40 | .40 | .43 | .39 | .37 | 73 | 73 | 73 | 73 | 73 |
| Missouri | 1.89 | 2.12 | 1.86 | 1.35 | 1.20 | 87 | 87 | 87 | 87 | 50 |
| Nebraska | — | — | — | — | — | — | — | — | — | — |
| North Dakota | .81 | .74 | .81 | .79 | .74 | 71 | 101 | 102 | 102 | 102 |
| South Dakota | — | — | — | — | — | — | — | — | — | — |
| **South Atlantic** | **1.63** | **1.28** | **.98** | **1.16** | **.95** | **144** | **143** | **119** | **115** | **120** |
| Delaware[1] | 29.62 | NM | — | — | — | 1,385 | 1,385 | — | — | — |
| District of Columbia | — | — | — | — | — | — | — | — | — | — |
| Florida | 1.23 | 1.15 | .78 | 1.01 | .87 | 69 | 69 | 69 | 67 | 73 |
| Georgia | — | — | — | — | 5.13 | — | — | — | — | NM |
| Maryland | — | — | — | — | — | — | — | — | — | — |
| North Carolina | — | — | — | — | — | — | — | — | — | — |
| South Carolina | .60 | .64 | .59 | .60 | .48 | 43 | 43 | 43 | 43 | 43 |
| Virginia | — | — | — | — | — | — | — | — | — | — |
| West Virginia | 2.55 | 2.23 | 2.09 | 2.33 | 1.44 | 259 | 260 | 217 | 209 | 216 |
| **East South Central** | **1.51** | **1.65** | **1.45** | **1.06** | **1.05** | **153** | **140** | **137** | **143** | **143** |
| Alabama | .94 | 1.00 | .69 | .82 | .57 | 82 | 80 | 80 | 80 | 80 |
| Kentucky | 1.70 | 1.91 | 1.76 | 1.60 | 1.58 | 155 | 135 | 132 | 140 | 140 |
| Mississippi | .41 | .30 | .27 | .27 | .35 | 70 | 70 | 70 | 70 | 70 |
| Tennessee | NM | NM | NM | .05 | .36 | 202 | 202 | 196 | 204 | 204 |
| **West South Central** | **1.17** | **1.22** | **1.01** | **1.08** | **.91** | **69** | **73** | **74** | **76** | **71** |
| Arkansas | — | — | — | — | — | — | — | — | — | — |
| Louisiana | NM | NM | NM | NM | NM | 75 | 75 | 75 | 75 | 75 |
| Oklahoma | .57 | .55 | .54 | .50 | .59 | 92 | 92 | 92 | 92 | 92 |
| Texas | 1.20 | 1.26 | 1.03 | 1.11 | .93 | 67 | 72 | 72 | 75 | 70 |
| **Mountain** | **.79** | **.69** | **.68** | **.73** | **.79** | **149** | **148** | **146** | **150** | **150** |
| Arizona | .63 | .68 | .42 | .77 | .88 | 175 | 175 | 160 | 175 | 175 |
| Colorado | .63 | .57 | .67 | .52 | .85 | 69 | 69 | 69 | 69 | 69 |
| Idaho | — | — | — | — | — | — | — | — | — | — |
| Montana | .94 | .90 | 1.10 | 1.11 | 1.14 | 274 | 274 | 274 | 274 | 274 |
| Nevada | 3.80 | .93 | .99 | .74 | 1.57 | 126 | 126 | 126 | 126 | 126 |
| New Mexico | 1.14 | 1.03 | 1.07 | 1.07 | 1.03 | 167 | 165 | 165 | 165 | 165 |
| Utah | .56 | .48 | .37 | .41 | .47 | 97 | 97 | 97 | 101 | 101 |
| Wyoming | .67 | .55 | .54 | .62 | .61 | 137 | 137 | 137 | 137 | 137 |
| **Pacific Contiguous** | — | — | — | — | — | — | — | — | — | — |
| California | — | — | — | — | — | — | — | — | — | — |
| Oregon | — | — | — | — | — | — | — | — | — | — |
| Washington | — | — | — | — | — | — | — | — | — | — |
| **Pacific Noncontiguous** | — | — | — | — | — | — | — | — | — | — |
| Alaska | — | — | — | — | — | — | — | — | — | — |
| Hawaii | — | — | — | — | — | — | — | — | — | — |
| **U.S. Average** | **1.40** | **1.32** | **1.19** | **1.14** | **1.16** | **130** | **132** | **125** | **127** | **126** |

[1] The high cost shown for Delaware is attributable to the flue gas desulfurization (FGD) units belonging to a plant that provides steam for sale and steam used to produce electricity. The FGD costs include the costs incurred in the production of steam for sale. In 1992 the plant was sold to a nonutility power producer.

O&M = Operation and Maintenance

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

Notes: •Data for 1995 are preliminary; 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 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1995

| 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 Co** | | | | | | | |
| 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 | Lime | 72.0 |
| Four Corners 5 | – | 818 | 8501 | .80 | Tray | Lime | 72.0 |
| **Atlantic City Electric Co** | | | | | | | |
| 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 River 1 | 1,710 | 570 | 8007 | .80 | Spray | Limestone | 90.0 |
| Laramie River 2 | – | 570 | 8107 | .80 | Spray | Limestone | 90.0 |
| Laramie River 3 | – | 570 | 8405 | .50 | Spray Dry | Lime/Alkaline Fly Ash | 85.0 |
| **Big Rivers Electric 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 |
| **Black Hills Corp** | | | | | | | |
| Neil Simpson II 2 | – | – | 9511 | .90 | Circulating Dry | Lime | 92.0 |
| **Central Illinois Light Co** | | | | | | | |
| Duck Creek 1 | 441 | 441 | 7607 | 3.40 | Venturi | Limestone | 86.0 |
| **Central Illinois Pub Serv Co** | | | | | | | |
| Newton 1 | 1,235 | 617 | 7912 | 4.00 | Spray | Sodium Carbonate | 90.0 |
| **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 |
| **Coop Power Assn** | | | | | | | |
| Coal Creek 1 | 1,012 | 506 | 7908 | 1.00 | Spray | Lime | 90.0 |
| Coal Creek 2 | – | 506 | 8107 | 1.00 | Spray | Lime | 90.0 |
| **Deseret Generation & Tran Coop** | | | | | | | |
| Bonanza 1-1 | 400 | 400 | 8605 | .50 | Spray | Limestone | 95.0 |
| **Duquesne Light Co** | | | | | | | |
| Elrama SCRB | 510 | 510 | 7609 | 2.50 | Venturi | Lime | 83.0 |
| F R Phillips SCRB | 411 | 411 | 7406 | 2.50 | Venturi | Lime | 83.0 |

See footnotes at end of table.

## Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1995 (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 | | | | | |
| **East Kentucky Power Coop Inc** | | | | | | | |
| H L Spurlock 2 | 814 | 508 | 8306 | 3.60 | Spray Dry | Lime | 90.0 |
| **Georgia Power Co** | | | | | | | |
| Yates Y1FG | 1,488 | 123 | 9210 | 2.50 | Bubbling Reactor | Limestone | 90.0 |
| **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 |
| **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 |
| **Houston Lighting & Power Co** | | | | | | | |
| Limestone FGD1 | 1,627 | 813 | 8511 | 3.10 | Spray | Limestone | 90.0 |
| Limestone FGD2 | – | 813 | 8611 | 3.10 | Spray | Limestone | 90.0 |
| W A Parish FGD8 | 3,953 | 615 | 8212 | .50 | Spray | Limestone | 85.0 |
| **Indianapolis Power & Light Co** | | | | | | | |
| Petersburg 3 | 1,873 | 574 | 7711 | – | Tray | Limestone | 85.0 |
| Petersburg 4 | – | 574 | 8604 | – | Spray | Limestone | 95.0 |
| **Jacksonville Electric Auth** | | | | | | | |
| 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** | | | | | | | |
| La Cygne 1 | 1,579 | 893 | 7306 | 5.40 | Venturi | Limestone | 80.0 |
| **Kentucky Utilities Co** | | | | | | | |
| 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 City of** | | | | | | | |
| Intermountain 1CCC | 1,640 | 820 | 8607 | .90 | Spray | Limestone | 90.0 |
| Intermountain 2CCC | – | 820 | 8707 | .30 | Spray | Limestone | 90.0 |
| **Louisville Gas & Electric Co** | | | | | | | |
| Cane Run 4 | 792 | 163 | 7612 | 3.50 | Packed | 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 | 1,690 | 460 | 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 & Light Co** | | | | | | | |
| Boswell Energy Cente AQCS2 | 1,073 | 558 | 8004 | 1.00 | Spray | Alkaline Fly Ash | 83.2 |
| Boswell Energy Cente SCR3 | – | 365 | 7302 | 1.00 | Spray | Alkaline Fly Ash | 25.4 |

See footnotes at end of table.

## Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1995 (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 | | | | | |
| **Minnesota Power & Light Co** | | | | | | | |
| Laskin Energy Center SCR1 | 116 | 58 | 7105 | 1.00 | Spray | Alkaline Fly Ash | – |
| Laskin Energy Center 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 Co** | | | | | | | |
| 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 |
| **Montana Power Co** | | | | | | | |
| Colstrip 1 | 2,273 | 358 | 7511 | .80 | Venturi | Lime/Alkaline Fly Ash | 58.8 |
| Colstrip 2 | – | 358 | 7608 | .80 | Venturi | Lime/Alkaline Fly Ash | 58.8 |
| Colstrip 3 | – | 778 | 8401 | .80 | Venturi | Lime/Alkaline Fly Ash | 95.0 |
| Colstrip 4 | – | 778 | 8604 | .80 | Venturi | Lime/Alkaline Fly Ash | 95.0 |
| **Montana-Dakota Utilities Co** | | | | | | | |
| Coyote FGD1 | 450 | 450 | 8105 | .80 | Spray Dry | Lime/Alkaline Fly Ash | 70.0 |
| **Muscatine City of** | | | | | | | |
| Muscatine 9 | 276 | 176 | 8306 | 3.20 | Spray | Limestone | 96.0 |
| **Nevada Power Co** | | | | | | | |
| 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 |
| **New York State Elec & Gas Corp** | | | | | | | |
| Kintigh 1 | 655 | 655 | 8408 | 3.60 | Spray | Limestone | 90.0 |
| Milliken 1 | 322 | 155 | 9506 | 3.20 | Spray | Limestone | 95.0 |
| Milliken 2 | – | 167 | 9501 | 3.20 | Spray | Limestone | 95.0 |
| **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 | Other | 90.0 |
| R M Schahfer 18 | – | 424 | 8602 | 3.20 | Spray | Other | 90.0 |
| **Northern States Power Co** | | | | | | | |
| Riverside 7 | 404 | 165 | 8101 | 1.30 | Spray Dry | Lime/Alkaline Fly Ash | 70.0 |
| Sherburne County 1 | 2,129 | 660 | 7605 | .90 | Venturi | Limestone/Alk Fly Ash | 50.0 |
| Sherburne County 2 | – | 660 | 7704 | .90 | Spray | Limestone/Alk Fly Ash | 50.0 |
| Sherburne County 3 | – | 809 | 8711 | .90 | Spray Dry | Lime/Alkaline Fly Ash | 72.3 |
| **Ohio Edison Co** | | | | | | | |
| Niles 1 | 266 | 266 | 9510 | 3.00 | Spray | Limestone | 95.0 |
| **Ohio Power Co** | | | | | | | |
| 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 Comm** | | | | | | | |
| Stanton Energy 1 | 929 | 465 | 8707 | 3.50 | Spray | Limestone | 90.0 |
| **Owensboro City of** | | | | | | | |
| Elmer Smith FGD | 416 | 416 | 9411 | 3.50 | Spray | Limestone | 96.0 |
| **PacifiCorp** | | | | | | | |
| Dave Johnston SC44 | 817 | 360 | 7202 | .40 | Venturi | Lime | – |
| Hunter (Emery) 1 | 1,339 | 446 | 7806 | .60 | Spray | Lime | 80.0 |
| Hunter (Emery) 2 | – | 446 | 8006 | .60 | Spray | Lime | 80.0 |
| Hunter (Emery) 3 | – | 446 | 8306 | .60 | Spray | Limestone | 90.0 |

See footnotes at end of table.

## Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1995 (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 | | | | | |
| **PacifiCorp** | | | | | | | |
| Huntington 1 | 893 | 446 | 7802 | 0.60 | Spray | Lime | 80.0 |
| Jim Bridger SC71 | 2,242 | 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 | – | 561 | 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 Electric Co** | | | | | | | |
| Conemaugh 1 | 1,872 | 936 | 9412 | 2.20 | Spray | Limestone | 95.0 |
| Conemaugh 2 | – | 936 | 9511 | 2.20 | Spray | Limestone | 95.0 |
| **Pennsylvania Power Co** | | | | | | | |
| 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 |
| **Philadelphia Electric Co** | | | | | | | |
| 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 |
| **Plains Elec Gen&Trans Coop Inc** | | | | | | | |
| Escalante 1 | 233 | 233 | 8412 | .80 | Spray | Limestone | 95.0 |
| **Platte River Power Authority** | | | | | | | |
| Rawhide 101 | 285 | 285 | 8404 | .30 | Spray Dry | Lime/Alkaline Fly Ash | 80.0 |
| **Public Service Co of Colorado** | | | | | | | |
| Cherokee 4 | 710 | 350 | 8905 | .40 | Spray Dry | Other | 26.0 |
| **Public Service Co of NM** | | | | | | | |
| San Juan 1 | 1,779 | 361 | 7804 | 1.30 | Tray | Other | 90.0 |
| San Juan 2 | – | 350 | 7808 | 1.30 | Tray | Other | 90.0 |
| San Juan 3 | – | 534 | 8203 | 1.30 | Tray | Other | 90.0 |
| San Juan 4 | – | 534 | 8204 | 1.30 | Tray | Other | 90.0 |
| **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 |
| **Richmond City of** | | | | | | | |
| Whitewater Valley LFC | – | – | 9410 | 2.10 | Spray Dry | Limestone | 72.5 |
| **Salt River Proj Ag I & P Dist** | | | | | | | |
| Coronado FGD1 | 822 | 411 | 7912 | 1.00 | Spray | Limestone | 82.5 |
| Coronado FGD2 | – | 411 | 8011 | 1.00 | Spray | Limestone | 82.5 |
| **San Antonio City of** | | | | | | | |
| 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 | 86.0 |
| Seminole 2 | – | 715 | 8412 | 3.00 | Spray | Limestone | 86.0 |
| **Sierra Pacific Power Co** | | | | | | | |
| North 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 |

See footnotes at end of table.

## Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1995 (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 | | | | | |
| **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 |
| 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** | | | | | | | |
| Dallman 33 | 388 | 207 | 8012 | 3.30 | Packed | Limestone | 95.0 |
| Southwest 1 | 194 | 194 | 7704 | 3.20 | Tray | Limestone | 87.0 |
| **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 |
| **Tampa Electric Co** | | | | | | | |
| Big Bend FGD4 | 1,823 | 486 | 8502 | 3.50 | Spray | Limestone | 90.0 |
| **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 | 444 | 444 | 8310 | 2.30 | Spray | Limestone | 90.0 |
| **Texas Utilities Electric Co** | | | | | | | |
| 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 |
| Twin Oak 1 | 1,602 | 801 | 304 | 1.60 | Spray | Limestone | 88.0 |
| Twin Oak 2 | – | 801 | 504 | 1.60 | Spray | Limestone | 88.0 |
| **Tri-State G & T Assn Inc** | | | | | | | |
| Craig C1 | 1,339 | 446 | 8010 | .40 | Spray | Limestone | 85.0 |
| Craig C2 | – | 446 | 8005 | .40 | Spray | Limestone | 85.0 |
| Craig C3 | – | 446 | 8410 | .40 | Spray Dry | Lime | 85.0 |

See footnotes at end of table.

## Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1995 (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 | | | | | |
| **Tucson Electric Power Co** | | | | | | | |
| Springerville 1 | 850 | 425 | 8506 | 0.70 | Spray Dry | Lime/Alkaline Fly Ash | 61.3 |
| Springerville 2 | – | 425 | 9006 | .70 | Spray Dry | Lime/Alkaline Fly Ash | 61.3 |
| **United Power Assn** | | | | | | | |
| Elk River 1 | 46 | 46 | 8903 | – | Spray Dry | Lime | 90.0 |
| Stanton 10 | 172 | 172 | 8206 | .70 | Spray Dry | Lime | 70.0 |
| **Virginia Electric & Power Co** | | | | | | | |
| Clover 1 | 848 | 424 | 9510 | 2.00 | Spray | Limestone | 90.0 |
| Mt Storm 3 | 1,662 | 522 | 9501 | 2.00 | Spray | Limestone | 90.0 |
| **West Penn Power Co** | | | | | | | |
| Mitchell 33 | 449 | 299 | 8208 | 4.00 | Spray | Lime | 95.0 |
| **West Texas Utilities Co** | | | | | | | |
| Oklaunion 1 | 720 | 720 | 8612 | .40 | Spray | Limestone | 86.8 |
| **Western Resources, Inc** | | | | | | | |
| Jeffrey Energy Centr 1 | 2,160 | 720 | 7807 | .30 | Spray | Limestone | 60.0 |
| Jeffrey Energy Centr 2 | – | 720 | 8005 | .30 | Spray | Limestone | 60.0 |
| Jeffrey Energy Centr 3 | – | 720 | 8305 | .30 | Spray | Limestone | 60.0 |
| Lawrence 4N | 604 | 114 | 6906 | .90 | Venturi | Limestone | 73.0 |
| Lawrence 4S | – | 114 | 6906 | .90 | Venturi | Limestone | 73.0 |
| Lawrence 5N | – | 403 | 7105 | .90 | Venturi | Limestone | 52.0 |
| Lawrence 5S | – | 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 are preliminary. • 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.[13] 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.

[13] 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. In the future, if the concept of an independent system operator takes hold, many power pools may reinvent themselves and operate under a new structure of rules.

## NERC Profile

The North American Electric Reliability Council (NERC) consists of 9 regional reliability councils whose memberships comprise essentially all of the electric utility systems in the contiguous United States, Canada, and Baja California Norte, Mexico. Part of the State of Alaska operates together and is an affiliate member; sometimes referenced as the tenth council. 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 14).

## 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. Recently, new 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-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.”

## Table 31. Sources and Disposition of Electricity at U.S. Electric Utilities, 1991 Through 1995

(Million Kilowatthours)

| Item | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Source** | | | | | |
| Net Generation | 2,835,377 | 2,805,092 | 2,897,815 | 2,924,961 | 3,004,538 |
| Purchases from Utilities | 1,127,669 | 1,146,323 | 1,218,882 | 1,226,814 | 1,282,677 |
| Purchases from Nonutilities | 139,436 | 166,283 | 188,537 | 208,778 | 222,115 |
| Net Exchange | 1,172 | –3,504 | –2,725 | –3,659 | 122 |
| Net Wheeling | 4,963 | 5,756 | 4,668 | 4,225 | 7,016 |
| **Disposition** | | | | | |
| Sales to Ultimate Consumers | 2,762,003 | 2,763,365 | 2,861,462 | 2,934,563 | 3,013,411 |
| Requirements and Nonrequirements Sales for Resale | 1,116,655 | 1,119,948 | 1,200,047 | 1,185,352 | 1,255,518 |
| Energy Furnished Without Charge | 4,210 | 4,409 | 5,003 | 4,762 | 5,365 |
| Energy Used by Utility Electric Department | 15,154 | 15,651 | 14,245 | 15,495 | 12,457 |
| Energy Losses[1] | 210,596 | 216,592 | 226,415 | 220,948 | 228,069 |

[1] 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 for 1995 are preliminary; data for prior years 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. •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 32. Net Generation from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| ECAR | 488,102 | 483,530 | 494,602 | 492,074 | 509,479 |
| ERCOT | 192,000 | 190,442 | 198,187 | 204,256 | 210,596 |
| MAAC | 197,235 | 193,330 | 205,552 | 206,221 | 203,801 |
| MAIN | 206,906 | 200,288 | 217,284 | 221,770 | 229,424 |
| MAPP(U.S.) | 122,991 | 120,053 | 124,808 | 124,607 | 130,642 |
| NPCC(U.S.) | 218,053 | 202,978 | 195,140 | 189,546 | 183,070 |
| SERC | 630,562 | 637,803 | 667,464 | 678,423 | 706,072 |
| SPP | 244,415 | 242,514 | 256,901 | 260,025 | 274,475 |
| WSCC(U.S.) | 523,468 | 522,863 | 527,428 | 537,399 | 546,205 |
| **Contiguous U.S.** | **2,823,732** | **2,793,801** | **2,887,366** | **2,914,320** | **2,993,763** |
| ASCC | 4,654 | 4,735 | 4,660 | 4,913 | 4,925 |
| Hawaii | 6,991 | 6,555 | 5,790 | 5,728 | 5,851 |
| **U.S. Total** | **2,835,377** | **2,805,092** | **2,897,815** | **2,924,961** | **3,004,538** |

Notes: •Data for 1995 are preliminary; data for prior years 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.

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

## Table 33. U.S. Electric Utility Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1991 Through 1995

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | All Sectors | Residential | Commercial | Industrial | Other[1] |
|---|---|---|---|---|---|
| | | | **1991** | | |
| ECAR | 430,314 | 134,703 | 98,125 | 187,458 | 10,029 |
| ERCOT | 204,319 | 73,819 | 53,249 | 68,425 | 8,826 |
| MAAC | 212,728 | 74,002 | 65,821 | 70,044 | 2,861 |
| MAIN | 201,815 | 61,856 | 55,904 | 75,196 | 8,859 |
| MAPP(U.S.) | 120,522 | 44,449 | 25,873 | 46,699 | 3,502 |
| NPCC(U.S.) | 233,643 | 76,755 | 85,036 | 57,668 | 14,185 |
| SERC | 601,988 | 239,154 | 157,981 | 187,386 | 17,467 |
| SPP | 238,328 | 84,615 | 60,682 | 84,701 | 8,330 |
| WSCC(U.S.) | 505,936 | 162,191 | 158,783 | 164,919 | 20,044 |
| **Contiguous U.S.** | **2,749,594** | **951,544** | **761,453** | **942,495** | **94,101** |
| ASCC | 4,255 | 1,603 | 2,005 | 466 | 182 |
| Hawaii | 8,154 | 2,270 | 2,205 | 3,623 | 55 |
| **U.S. Total** | **2,762,003** | **955,417** | **765,664** | **946,583** | **94,339** |
| | | | **1992** | | |
| ECAR | 429,591 | 129,847 | 97,007 | 192,916 | 9,820 |
| ERCOT | 203,206 | 71,802 | 53,342 | 69,306 | 8,755 |
| MAAC | 210,799 | 72,221 | 65,971 | 69,797 | 2,810 |
| MAIN | 200,571 | 56,685 | 54,013 | 81,314 | 8,558 |
| MAPP(U.S.) | 117,283 | 41,724 | 25,510 | 46,877 | 3,171 |
| NPCC(U.S.) | 233,393 | 76,773 | 84,839 | 57,553 | 14,228 |
| SERC | 609,139 | 239,899 | 153,232 | 198,441 | 17,567 |
| SPP | 235,320 | 80,251 | 59,964 | 87,121 | 7,984 |
| WSCC(U.S.) | 511,395 | 162,773 | 163,083 | 165,208 | 20,331 |
| **Contiguous U.S.** | **2,750,695** | **931,976** | **756,962** | **968,534** | **93,223** |
| ASCC | 4,338 | 1,640 | 2,034 | 504 | 160 |
| Hawaii | 8,332 | 2,323 | 2,274 | 3,676 | 59 |
| **U.S. Total** | **2,763,365** | **935,939** | **761,271** | **972,714** | **93,442** |
| | | | **1993** | | |
| ECAR | 447,062 | 139,068 | 108,441 | 189,527 | 10,026 |
| ERCOT | 212,182 | 76,887 | 55,602 | 70,508 | 9,185 |
| MAAC | 220,037 | 77,450 | 69,026 | 70,687 | 2,873 |
| MAIN | 207,004 | 61,610 | 57,843 | 78,858 | 8,693 |
| MAPP(U.S.) | 124,143 | 44,718 | 26,568 | 49,353 | 3,504 |
| NPCC(U.S.) | 236,012 | 78,417 | 86,723 | 56,570 | 14,302 |
| SERC | 638,223 | 256,275 | 158,893 | 204,832 | 18,223 |
| SPP | 249,888 | 88,012 | 62,962 | 90,606 | 8,308 |
| WSCC(U.S.) | 514,212 | 168,376 | 164,167 | 162,076 | 19,593 |
| **Contiguous U.S.** | **2,848,766** | **990,812** | **790,229** | **973,017** | **94,708** |
| ASCC | 4,374 | 1,629 | 2,062 | 501 | 182 |
| Hawaii | 8,325 | 2,340 | 2,285 | 3,646 | 54 |
| **U.S. Total** | **2,861,462** | **994,781** | **794,573** | **977,164** | **94,944** |

See footnotes at end of table.

## Table 33. U.S. Electric Utility Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1991 Through 1995 (Continued)

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | All Sectors | Residential | Commercial | Industrial | Other[1] |
|---|---|---|---|---|---|
| | | | **1994** | | |
| ECAR | 459,747 | 139,521 | 111,731 | 198,793 | 9,701 |
| ERCOT | 218,781 | 78,708 | 57,209 | 73,248 | 9,615 |
| MAAC | 223,635 | 78,264 | 75,475 | 66,999 | 2,897 |
| MAIN | 214,304 | 62,094 | 60,086 | 83,056 | 9,068 |
| MAPP(U.S.) | 128,935 | 45,372 | 28,015 | 51,776 | 3,771 |
| NPCC(U.S.) | 238,679 | 79,177 | 89,591 | 55,255 | 14,656 |
| SERC | 656,478 | 261,240 | 164,290 | 212,424 | 18,524 |
| SPP | 257,183 | 88,909 | 65,485 | 94,302 | 8,488 |
| WSCC(U.S.) | 523,696 | 171,081 | 163,782 | 167,957 | 20,876 |
| **Contiguous U.S.** | **2,921,437** | **1,004,366** | **815,664** | **1,003,811** | **97,596** |
| ASCC | 4,533 | 1,688 | 2,155 | 511 | 179 |
| Hawaii | 8,593 | 2,428 | 2,451 | 3,659 | 56 |
| **U.S. Total** | **2,934,563** | **1,008,482** | **820,269** | **1,007,981** | **97,830** |
| | | | **1995** | | |
| ECAR | 477,416 | 147,184 | 116,093 | 204,192 | 9,946 |
| ERCOT | 222,465 | 81,158 | 59,065 | 72,542 | 9,700 |
| MAAC | 227,533 | 79,484 | 86,687 | 58,440 | 2,922 |
| MAIN | 218,729 | 66,039 | 62,817 | 80,668 | 9,204 |
| MAPP(U.S.) | 134,495 | 47,489 | 29,530 | 53,636 | 3,839 |
| NPCC(U.S.) | 238,484 | 78,611 | 94,236 | 51,604 | 14,034 |
| SERC | 686,425 | 273,476 | 172,423 | 221,293 | 19,234 |
| SPP | 266,811 | 93,463 | 67,387 | 97,375 | 8,586 |
| WSCC(U.S.) | 527,616 | 171,477 | 169,779 | 168,645 | 17,715 |
| **Contiguous U.S.** | **2,999,973** | **1,038,381** | **858,017** | **1,008,395** | **95,179** |
| ASCC | 4,631 | 1,713 | 2,200 | 546 | 172 |
| Hawaii | 8,806 | 2,471 | 2,625 | 3,655 | 55 |
| **U.S. Total** | **3,013,411** | **1,042,565** | **862,841** | **1,012,597** | **95,407** |

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

Notes: •Data for 1995 are preliminary; data for prior years 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 34. Generating Capability at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, as of December 1991 Through 1995

(Megawatts)

| North American Electric Reliability Council Region and Hawaii | 1991[R] | 1992[R] | 1993[R] | 1994[R] | 1995 |
|---|---|---|---|---|---|
| ECAR | 104,469 | 104,591 | 104,748 | 104,553 | 104,426 |
| ERCOT | 51,206 | 51,688 | 52,889 | 52,948 | 53,400 |
| MAAC | 51,331 | 51,553 | 51,589 | 51,494 | 52,083 |
| MAIN | 49,544 | 49,730 | 50,314 | 50,862 | 51,430 |
| MAPP(U.S.) | 31,057 | 30,964 | 30,906 | 31,357 | 31,311 |
| NPCC(U.S.) | 55,443 | 54,637 | 56,043 | 55,956 | 55,567 |
| SERC | 146,429 | 147,747 | 148,686 | 150,230 | 153,434 |
| SPP | 70,642 | 70,771 | 70,998 | 71,085 | 71,375 |
| WSCC(U.S.) | 129,345 | 129,501 | 129,110 | 128,800 | 129,752 |
| **Contiguous U.S.** | **689,466** | **691,182** | **695,283** | **697,285** | **702,779** |
| ASCC | 1,547 | 1,670 | 1,711 | 1,737 | 1,732 |
| Hawaii | 1,521 | 1,560 | 1,602 | 1,602 | 1,602 |
| **U.S. Total** | **692,534** | **694,412** | **698,595** | **700,623** | **706,112** |

R = Revised data.

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

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

## Table 35. Noncoincidental Peak Load at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Megawatts)

| North American Electric Reliability Council Region and Hawaii | Actual | | | | |
|---|---|---|---|---|---|
| | 1991 | 1992 | 1993 | 1994 | 1995 |
| | | | **Summer** | | |
| ECAR | 81,539 | 78,550 | 85,930 | 87,165 | 92,619 |
| ERCOT | 41,870 | 42,619 | 44,255 | 44,162 | 46,618 |
| MAAC | 45,937 | 43,658 | 46,494 | 46,019 | 48,577 |
| MAIN | 41,598 | 38,819 | 41,956 | 42,562 | 45,782 |
| MAPP(U.S.) | 25,498 | 22,638 | 24,396 | 27,000 | 29,192 |
| NPCC(U.S.) | 46,594 | 43,658 | 46,706 | 47,581 | 47,705 |
| SERC | 124,688 | 128,236 | 136,101 | 132,584 | 146,569 |
| SPP | 51,885 | 51,324 | 57,106 | 56,035 | 59,595 |
| WSCC(U.S.) | 92,096 | 99,205 | 97,809 | 102,212 | 103,592 |
| **Contiguous U.S.** | **551,705** | **548,707** | **580,753** | **585,320** | **620,249** |
| ASCC | 471 | 504 | 511 | 524 | 622 |
| Hawaii | 1 | 1 | 1 | 1 | 1 |
| **U.S. Total** | **551,176** | **549,211** | **581,264** | **585,844** | **620,871** |
| | | | **Winter** | | |
| ECAR | 71,181 | 72,885 | 81,846 | 75,638 | 83,465 |
| ERCOT | 35,448 | 35,055 | 35,407 | 36,180 | 36,965 |
| MAAC | 37,983 | 37,915 | 41,406 | 40,653 | 40,790 |
| MAIN | 33,420 | 31,289 | 34,966 | 33,999 | 35,734 |
| MAPP(U.S.) | 21,432 | 21,866 | 21,955 | 23,033 | 23,429 |
| NPCC(U.S.) | 41,786 | 41,125 | 42,063 | 42,547 | 42,755 |
| SERC | 119,575 | 121,250 | 133,635 | 132,661 | 142,032 |
| SPP | 38,759 | 39,912 | 41,644 | 42,505 | 44,626 |
| WSCC(U.S.) | 86,097 | 91,686 | 88,811 | 91,037 | 94,890 |
| **Contiguous U.S.** | **485,681** | **492,983** | **521,733** | **518,253** | **544,684** |
| ASCC | 622 | 635 | 632 | 641 | 676 |
| Hawaii | 1 | 1 | 1 | 1 | 1 |
| **U.S. Total** | **486,303** | **493,618** | **522,365** | **518,894** | **545,360** |
| | **Projected** | | | | |
| | **1996** | **1997** | **1998** | **2000** | **2005** |
| | | | **Summer** | | |
| ECAR | 88,347 | 90,917 | 92,299 | 95,832 | 104,213 |
| ERCOT | 47,354 | 48,293 | 49,128 | 51,104 | 56,843 |
| MAAC | 47,238 | 47,923 | 48,623 | 50,044 | 53,082 |
| MAIN | 45,045 | 45,882 | 46,657 | 48,162 | 51,735 |
| MAPP(U.S.) | 29,465 | 30,182 | 30,856 | 31,973 | 34,981 |
| NPCC(U.S.) | 48,290 | 48,660 | 49,238 | 50,481 | 52,747 |
| SERC | 145,755 | 149,017 | 151,666 | 158,102 | 174,948 |
| SPP | 60,332 | 61,425 | 62,461 | 64,614 | 70,042 |
| WSCC(U.S.) | 103,703 | 105,877 | 107,300 | 110,583 | 119,483 |
| **Contiguous U.S.** | **615,529** | **628,176** | **638,228** | **660,895** | **718,074** |
| ASCC | 551 | 566 | 564 | 591 | 630 |
| Hawaii | 1 | 1 | 1 | 1 | 1 |
| **U.S. Total** | **616,080** | **628,742** | **638,792** | **661,486** | **718,704** |
| | | | **Winter** | | |
| ECAR | 81,901 | 83,203 | 84,758 | 87,633 | 92,646 |
| ERCOT | 38,026 | 38,960 | 39,406 | 41,455 | 46,620 |
| MAAC | 41,891 | 42,678 | 43,301 | 44,748 | 47,413 |
| MAIN | 35,496 | 36,120 | 36,812 | 38,011 | 40,951 |
| MAPP(U.S.) | 24,069 | 24,521 | 25,066 | 25,946 | 28,168 |
| NPCC(U.S.) | 43,420 | 43,830 | 44,401 | 45,464 | 47,669 |
| SERC | 139,214 | 141,870 | 145,294 | 152,140 | 167,459 |
| SPP | 44,397 | 44,982 | 45,666 | 47,380 | 51,375 |
| WSCC(U.S.) | 96,647 | 97,955 | 99,453 | 102,269 | 110,445 |
| **Contiguous U.S.** | **545,061** | **554,119** | **564,157** | **585,046** | **632,736** |
| ASCC | 710 | 716 | 722 | 755 | 806 |
| Hawaii | 1 | 1 | 1 | 1 | 1 |
| **U.S. Total** | **545,771** | **554,835** | **564,879** | **585,801** | **633,542** |

[1] Data for Hawaii are not submitted for this form.

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

Sources: **Data for 1995 and beyond:** Form EIA-411, *Coordinated Bulk Power Supply Programs;* **Data for prior years:** Department of Energy, Office of Emergency Policy, Form OE-411, *''Coordinated Regional Bulk Power Supply Program.''*

## Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | Total Receipts[1] | Purchased Power | Exchange Received | Wheeling Received |
|---|---|---|---|---|
| | | **1991** | | |
| ECAR | 195,606 | 151,284 | 14,030 | 30,293 |
| ERCOT | 127,343 | 57,805 | 48,603 | 20,934 |
| MAAC | 84,589 | 61,395 | 17,352 | 5,842 |
| MAIN | 58,405 | 48,165 | 6,420 | 3,819 |
| MAPP(U.S.) | 114,659 | 78,176 | 26,999 | 9,484 |
| NPCC(U.S.) | 211,379 | 140,964 | 13,242 | 57,173 |
| SERC | 381,671 | 321,277 | 31,937 | 28,457 |
| SPP | 150,048 | 122,420 | 5,477 | 22,150 |
| WSCC(U.S.) | 503,361 | 281,676 | 77,218 | 144,466 |
| **Contiguous U.S.** | **1,827,060** | **1,263,162** | **241,278** | **322,620** |
| ASCC | 2,876 | 2,343 | 20 | 514 |
| Hawaii | 1,605 | 1,601 | 4 | 0 |
| **U.S. Total** | **1,831,541** | **1,267,106** | **241,302** | **323,133** |
| | | **1992** | | |
| ECAR | 190,220 | 155,564 | 2,853 | 31,803 |
| ERCOT | 130,049 | 59,661 | 46,311 | 24,077 |
| MAAC | 92,676 | 71,675 | 11,134 | 9,868 |
| MAIN | 55,810 | 52,108 | 213 | 3,489 |
| MAPP(U.S.) | 125,334 | 81,610 | 32,062 | 11,661 |
| NPCC(U.S.) | 227,570 | 163,419 | 3,464 | 60,687 |
| SERC | 378,689 | 325,039 | 26,439 | 27,211 |
| SPP | 150,335 | 123,644 | 4,943 | 21,749 |
| WSCC(U.S.) | 478,769 | 275,031 | 76,224 | 127,514 |
| **Contiguous U.S.** | **1,829,453** | **1,307,750** | **203,643** | **318,060** |
| ASCC | 3,021 | 2,531 | 12 | 478 |
| Hawaii | 2,328 | 2,324 | 4 | 0 |
| **U.S. Total** | **1,834,801** | **1,312,605** | **203,658** | **318,538** |
| | | **1993** | | |
| ECAR | 201,396 | 167,278 | 2,927 | 31,191 |
| ERCOT | 144,491 | 63,523 | 54,253 | 26,716 |
| MAAC | 93,051 | 76,663 | 3,256 | 13,132 |
| MAIN | 67,930 | 62,511 | 400 | 5,018 |
| MAPP(U.S.) | 109,222 | 89,875 | 2,567 | 16,781 |
| NPCC(U.S.) | 249,585 | 178,147 | 3,622 | 67,815 |
| SERC | 398,660 | 341,136 | 30,391 | 27,132 |
| SPP | 166,846 | 135,037 | 6,282 | 25,528 |
| WSCC(U.S.) | 485,155 | 287,564 | 59,660 | 137,931 |
| **Contiguous U.S.** | **1,916,336** | **1,401,733** | **163,359** | **351,244** |
| ASCC | 3,039 | 2,582 | 0 | 456 |
| Hawaii | 3,106 | 3,103 | 3 | 0 |
| **U.S. Total** | **1,922,481** | **1,407,419** | **163,361** | **351,701** |

See footnotes at end of table.

## Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995 (Continued)

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | Total Receipts[1] | Purchased Power | Exchange Received | Wheeling Received |
|---|---|---|---|---|
| | | **1994** | | |
| ECAR | 199,000 | 166,157 | 1,982 | 30,861 |
| ERCOT | 141,092 | 61,901 | 55,122 | 24,069 |
| MAAC | 94,910 | 79,907 | 3,214 | 11,789 |
| MAIN | 66,538 | 61,159 | 502 | 4,877 |
| MAPP(U.S.) | 109,057 | 87,606 | 2,414 | 19,038 |
| NPCC(U.S.) | 267,351 | 194,510 | 3,957 | 68,883 |
| SERC | 397,661 | 340,918 | 31,609 | 25,134 |
| SPP | 172,119 | 142,619 | 5,955 | 23,545 |
| WSCC(U.S.) | 472,025 | 294,190 | 49,919 | 127,915 |
| **Contiguous U.S.** | **1,919,751** | **1,428,966** | **154,675** | **336,111** |
| ASCC | 3,952 | 3,184 | 73 | 695 |
| Hawaii | 3,444 | 3,442 | 3 | 0 |
| **U.S. Total** | **1,927,147** | **1,435,591** | **154,750** | **336,805** |
| | | **1995** | | |
| ECAR | 224,659 | 188,967 | 2,158 | 33,534 |
| ERCOT | 145,430 | 61,215 | 50,420 | 33,795 |
| MAAC | 114,217 | 98,774 | 528 | 14,915 |
| MAIN | 67,367 | 60,707 | 389 | 6,270 |
| MAPP(U.S.) | 112,723 | 92,082 | 2,826 | 17,816 |
| NPCC(U.S.) | 263,040 | 199,071 | 4,080 | 59,890 |
| SERC | 424,578 | 352,259 | 41,550 | 30,769 |
| SPP | 175,992 | 146,965 | 5,525 | 23,502 |
| WSCC(U.S.) | 484,169 | 297,932 | 51,633 | 134,604 |
| **Contiguous U.S.** | **2,012,175** | **1,497,973** | **159,108** | **355,094** |
| ASCC | 4,217 | 3,301 | 137 | 779 |
| Hawaii | 3,522 | 3,518 | 4 | 0 |
| **U.S. Total** | **2,019,915** | **1,504,792** | **159,249** | **355,874** |

[1] Equals purchased power plus exchange received plus wheeling received.

Notes: •Data for 1995 are preliminary; data for prior years are final. •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, import, export, and nonutility transactions.

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

## Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | Total Deliveries[1] | Requirements and Nonrequirements Sales for Resale | Exchange Delivered | Wheeling Delivered |
|---|---|---|---|---|
| | | **1991** | | |
| ECAR | 221,435 | 182,081 | 9,193 | 30,161 |
| ERCOT | 101,790 | 31,383 | 49,470 | 20,937 |
| MAAC | 51,289 | 31,670 | 13,776 | 5,842 |
| MAIN | 48,267 | 38,135 | 6,392 | 3,739 |
| MAPP(U.S.) | 106,020 | 68,849 | 29,235 | 7,935 |
| NPCC(U.S.) | 177,038 | 112,478 | 7,635 | 56,925 |
| SERC | 364,167 | 306,718 | 30,001 | 27,447 |
| SPP | 136,561 | 107,884 | 6,600 | 22,078 |
| WSCC(U.S.) | 465,535 | 235,142 | 87,801 | 142,592 |
| **Contiguous U.S.** | **1,672,100** | **1,114,341** | **240,103** | **317,656** |
| ASCC | 2,849 | 2,314 | 21 | 514 |
| Hawaii | 5 | 0 | 5 | 0 |
| **U.S. Total** | **1,674,954** | **1,116,655** | **240,130** | **318,170** |
| | | **1992** | | |
| ECAR | 212,729 | 178,224 | 2,887 | 31,618 |
| ERCOT | 102,966 | 32,299 | 46,577 | 24,090 |
| MAAC | 59,416 | 48,364 | 1,272 | 9,779 |
| MAIN | 40,706 | 37,240 | 62 | 3,404 |
| MAPP(U.S.) | 116,200 | 71,447 | 33,906 | 10,847 |
| NPCC(U.S.) | 178,603 | 116,451 | 1,657 | 60,495 |
| SERC | 357,147 | 300,686 | 31,053 | 25,408 |
| SPP | 137,540 | 109,595 | 6,306 | 21,639 |
| WSCC(U.S.) | 431,563 | 223,114 | 83,426 | 125,023 |
| **Contiguous U.S.** | **1,636,870** | **1,117,421** | **207,145** | **312,304** |
| ASCC | 3,020 | 2,528 | 14 | 478 |
| Hawaii | 3 | 0 | 3 | 0 |
| **U.S. Total** | **1,639,893** | **1,119,948** | **207,162** | **312,782** |
| | | **1993** | | |
| ECAR | 216,294 | 182,147 | 3,153 | 30,994 |
| ERCOT | 114,854 | 33,760 | 54,409 | 26,686 |
| MAAC | 60,556 | 47,525 | 1 | 13,030 |
| MAIN | 62,541 | 57,410 | 180 | 4,951 |
| MAPP(U.S.) | 98,325 | 77,943 | 4,251 | 16,130 |
| NPCC(U.S.) | 189,109 | 119,632 | 1,923 | 67,553 |
| SERC | 374,073 | 321,445 | 27,304 | 25,324 |
| SPP | 151,816 | 119,353 | 7,044 | 25,419 |
| WSCC(U.S.) | 442,657 | 238,351 | 67,816 | 136,489 |
| **Contiguous U.S.** | **1,710,224** | **1,197,567** | **166,081** | **346,576** |
| ASCC | 2,936 | 2,480 | 0 | 456 |
| Hawaii | 5 | 0 | 5 | 0 |
| **U.S. Total** | **1,713,165** | **1,200,047** | **166,086** | **347,032** |

See footnotes at end of table.

## Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995 (Continued)

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | Total Deliveries[1] | Requirements and Nonrequirements Sales for Resale | Exchange Delivered | Wheeling Delivered |
|---|---|---|---|---|
| | | **1994** | | |
| ECAR | 199,188 | 166,045 | 2,513 | 30,630 |
| ERCOT | 112,985 | 33,536 | 55,360 | 24,088 |
| MAAC | 60,205 | 48,483 | 2 | 11,720 |
| MAIN | 58,584 | 53,490 | 284 | 4,810 |
| MAPP(U.S.) | 92,834 | 70,181 | 4,236 | 18,417 |
| NPCC(U.S.) | 198,490 | 128,171 | 1,731 | 68,587 |
| SERC | 367,081 | 312,497 | 31,071 | 23,514 |
| SPP | 153,989 | 124,902 | 5,638 | 23,448 |
| WSCC(U.S.) | 429,034 | 244,874 | 57,489 | 126,672 |
| **Contiguous U.S.** | **1,672,389** | **1,182,180** | **158,324** | **331,885** |
| ASCC | 3,945 | 3,172 | 78 | 695 |
| Hawaii | 6 | 0 | 6 | 0 |
| **U.S. Total** | **1,676,341** | **1,185,352** | **158,409** | **332,580** |
| | | **1995** | | |
| ECAR | 222,034 | 186,466 | 2,270 | 33,298 |
| ERCOT | 118,456 | 34,017 | 50,644 | 33,796 |
| MAAC | 71,357 | 56,800 | 9 | 14,548 |
| MAIN | 61,427 | 55,044 | 209 | 6,175 |
| MAPP(U.S.) | 95,275 | 74,394 | 4,285 | 16,596 |
| NPCC(U.S.) | 186,496 | 124,588 | 2,282 | 59,626 |
| SERC | 393,683 | 327,687 | 37,116 | 28,880 |
| SPP | 161,207 | 132,687 | 5,113 | 23,406 |
| WSCC(U.S.) | 449,418 | 260,585 | 57,080 | 131,752 |
| **Contiguous U.S.** | **1,759,354** | **1,252,268** | **159,007** | **348,078** |
| ASCC | 4,138 | 3,250 | 109 | 779 |
| Hawaii | 11 | 0 | 11 | 0 |
| **U.S. Total** | **1,763,503** | **1,255,518** | **159,127** | **348,858** |

[1] Equals sales for resale plus exchange delivered plus wheeling delivered.

Notes: •Data for 1995 are preliminary; data for prior years are final. •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, import, export, and nonutility transactions.

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

## Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | Net Energy Flow[1] | Receipts[2] | Deliveries[3] |
|---|---|---|---|
| | | **1991** | |
| ECAR | –25,829 | 195,606 | 221,435 |
| ERCOT | 25,553 | 127,343 | 101,790 |
| MAAC | 33,300 | 84,589 | 51,289 |
| MAIN | 10,138 | 58,405 | 48,267 |
| MAPP(U.S.) | 8,640 | 114,659 | 106,020 |
| NPCC(U.S.) | 34,340 | 211,379 | 177,038 |
| SERC | 17,505 | 381,671 | 364,167 |
| SPP | 13,487 | 150,048 | 136,561 |
| WSCC(U.S.) | 37,826 | 503,361 | 465,535 |
| **Contiguous U.S.** | **154,960** | **1,827,060** | **1,672,100** |
| ASCC | 27 | 2,876 | 2,849 |
| Hawaii | 1,600 | 1,605 | 5 |
| **U.S. Total** | **156,586** | **1,831,541** | **1,674,954** |
| | | **1992** | |
| ECAR | –22,509 | 190,220 | 212,729 |
| ERCOT | 27,082 | 130,049 | 102,966 |
| MAAC | 33,260 | 92,676 | 59,416 |
| MAIN | 15,105 | 55,810 | 40,706 |
| MAPP(U.S.) | 9,134 | 125,334 | 116,200 |
| NPCC(U.S.) | 48,967 | 227,570 | 178,603 |
| SERC | 21,542 | 378,689 | 357,147 |
| SPP | 12,795 | 150,335 | 137,540 |
| WSCC(U.S.) | 47,206 | 478,769 | 431,563 |
| **Contiguous U.S.** | **192,583** | **1,829,453** | **1,636,870** |
| ASCC | 1 | 3,021 | 3,020 |
| Hawaii | 2,325 | 2,328 | 3 |
| **U.S. Total** | **194,909** | **1,834,801** | **1,639,893** |
| | | **1993** | |
| ECAR | –14,898 | 201,396 | 216,294 |
| ERCOT | 29,637 | 144,491 | 114,854 |
| MAAC | 32,495 | 93,051 | 60,556 |
| MAIN | 5,388 | 67,930 | 62,541 |
| MAPP(U.S.) | 10,898 | 109,222 | 98,325 |
| NPCC(U.S.) | 60,476 | 249,585 | 189,109 |
| SERC | 24,587 | 398,660 | 374,073 |
| SPP | 15,031 | 166,846 | 151,816 |
| WSCC(U.S.) | 42,498 | 485,155 | 442,657 |
| **Contiguous U.S.** | **206,112** | **1,916,336** | **1,710,224** |
| ASCC | 103 | 3,039 | 2,936 |
| Hawaii | 3,101 | 3,106 | 5 |
| **U.S. Total** | **209,316** | **1,922,481** | **1,713,165** |

See footnotes at end of table.

## Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995 (Continued)

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | Net Energy Flow[1] | Receipts[2] | Deliveries[3] |
|---|---|---|---|
| | | **1994** | |
| ECAR | –188 | 199,000 | 199,188 |
| ERCOT | 28,107 | 141,092 | 112,985 |
| MAAC | 34,705 | 94,910 | 60,205 |
| MAIN | 7,954 | 66,538 | 58,584 |
| MAPP(U.S.) | 16,223 | 109,057 | 92,834 |
| NPCC(U.S.) | 68,861 | 267,351 | 198,490 |
| SERC | 30,580 | 397,661 | 367,081 |
| SPP | 18,130 | 172,119 | 153,989 |
| WSCC(U.S.) | 42,990 | 472,025 | 429,034 |
| **Contiguous U.S.** | **247,362** | **1,919,751** | **1,672,389** |
| ASCC | 6 | 3,952 | 3,945 |
| Hawaii | 3,438 | 3,444 | 6 |
| **U.S. Total** | **250,806** | **1,927,147** | **1,676,341** |
| | | **1995** | |
| ECAR | 2,625 | 224,659 | 222,034 |
| ERCOT | 26,974 | 145,430 | 118,456 |
| MAAC | 42,860 | 114,217 | 71,357 |
| MAIN | 5,940 | 67,367 | 61,427 |
| MAPP(U.S.) | 17,448 | 112,723 | 95,275 |
| NPCC(U.S.) | 76,544 | 263,040 | 186,496 |
| SERC | 30,895 | 424,578 | 393,683 |
| SPP | 14,785 | 175,992 | 161,207 |
| WSCC(U.S.) | 34,751 | 484,169 | 449,418 |
| **Contiguous U.S.** | **252,821** | **2,012,175** | **1,759,354** |
| ASCC | 79 | 4,217 | 4,138 |
| Hawaii | 3,512 | 3,522 | 11 |
| **U.S. Total** | **256,412** | **2,019,915** | **1,763,503** |

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

Notes: •Data for 1995 are preliminary; data for prior years are final. •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, import, export, and nonutility transactions.

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

## Table 39. U.S. Electric Utility Purchases of Nonutility Generated Electricity by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| ECAR | 8,649 | 10,420 | 11,962 | 12,659 | 13,131 |
| ERCOT | 23,036 | 23,666 | 24,267 | 23,264 | 22,653 |
| MAAC | 12,721 | 16,433 | 18,083 | 20,911 | 23,870 |
| MAIN | 273 | 347 | 401 | 392 | 447 |
| MAPP(U.S.) | 1,563 | 576 | 582 | 585 | 585 |
| NPCC(U.S.) | 23,220 | 36,116 | 42,724 | 49,348 | 57,513 |
| SERC | 12,914 | 15,304 | 19,021 | 24,020 | 29,184 |
| SPP | 5,705 | 5,457 | 6,809 | 6,856 | 5,345 |
| WSCC(U.S.) | 49,951 | 55,637 | 61,580 | 67,297 | 65,863 |
| **Contiguous U.S.** | **138,033** | **163,957** | **185,429** | **205,332** | **218,590** |
| ASCC | 1 | 1 | 4 | 4 | 7 |
| Hawaii | 1,402 | 2,324 | 3,103 | 3,442 | 3,518 |
| **U.S. Total** | **139,436** | **166,283** | **188,537** | **208,778** | **222,115** |

Notes: •Data for 1995 are preliminary; data for prior years 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 40. Net Imports at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Thousand Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| ECAR | −446,412 | −231,967 | 931,679 | 6,906,673 | 5,758,866 |
| ERCOT | −195,548 | −169,142 | −7,760 | −25,191 | −6,475 |
| MAAC | -- | -- | -- | -- | -- |
| MAIN | -- | -- | -- | -- | -- |
| MAPP(U.S.) | 3,307,714 | 6,921,800 | 7,808,685 | 9,380,144 | 9,858,469 |
| NPCC(U.S.) | 10,989,137 | 12,053,907 | 16,756,045 | 23,535,934 | 22,309,577 |
| SERC | -- | -- | -- | -- | -- |
| SPP | -- | -- | -- | -- | -- |
| WSCC(U.S.) | 8,617,259 | 9,773,701 | 2,938,533 | 4,840,154 | −306,773 |
| **Contiguous U.S.** | **22,272,150** | **28,348,299** | **28,427,182** | **44,637,717** | **37,613,664** |
| ASCC | * | * | * | * | * |
| Hawaii | -- | -- | -- | -- | -- |
| **U.S. Total** | **22,272,150** | **28,348,299** | **28,427,182** | **44,637,717** | **37,613,664** |
| Net Canada | 20,773,039 | 31,927,468 | 27,283,021 | 43,695,066 | 36,510,673 |
| Net Mexico | 1,499,111 | 1,032,552 | 1,144,160 | 942,651 | 1,102,990 |

* =Value less than 0.5.

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •Values identify point of entry or exit, but do not necessarily identify point of consumption. •These data reflect electricity trade with Canada and Mexico. •Net imports data represent gross imports minus gross exports.

Source: Office of Fuels Programs, Fossil Energy, Form FE-781R, ''Annual Report of International Electric Export/Import Data.''

## Table 41. Imports to U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Thousand Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| ECAR | 106,606 | 82,151 | 959,746 | 6,909,598 | 5,798,944 |
| ERCOT | 14 | -- | 14 | 70 | 0 |
| MAAC | -- | -- | -- | -- | -- |
| MAIN | -- | -- | -- | -- | -- |
| MAPP(U.S.) | 4,708,775 | 8,573,652 | 10,767,276 | 10,130,216 | 10,332,719 |
| NPCC(U.S.) | 13,051,823 | 14,699,638 | 18,741,212 | 25,080,505 | 23,413,069 |
| SERC | -- | -- | -- | -- | -- |
| SPP | -- | -- | -- | -- | -- |
| WSCC(U.S.) | 12,945,048 | 13,848,735 | 8,613,566 | 10,109,276 | 7,215,641 |
| **Contiguous U.S.** | **30,812,266** | **37,204,176** | **39,081,814** | **52,229,668** | **46,760,374** |
| ASCC | * | * | * | * | * |
| Hawaii | -- | -- | -- | -- | -- |
| **U.S. Total** | **30,812,266** | **37,204,176** | **39,081,814** | **52,229,668** | **46,760,374** |
| From Canada | 28,696,527 | 35,181,757 | 37,088,486 | 50,218,349 | 44,502,962 |
| From Mexico | 2,115,739 | 2,022,419 | 1,993,327 | 2,011,319 | 2,257,411 |

* =Value less than 0.5.

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •Values identify point of entry or exit, but do not necessarily identify point of consumption. •These data reflect electricity imported from Canada and Mexico.

Source: Office of Fuels Programs, Fossil Energy, Form FE-781R, ''Annual Report of International Electric Export/Import Data.''

## Table 42. Exports from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1991 Through 1995

(Thousand Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| ECAR | 553,018 | 314,118 | 28,067 | 2,925 | 40,078 |
| ERCOT | 195,562 | 169,142 | 7,774 | 25,261 | 6,475 |
| MAAC | –- | –- | –- | –- | –- |
| MAIN | –- | –- | –- | –- | –- |
| MAPP(U.S.) | 1,401,061 | 1,651,852 | 2,958,591 | 750,072 | 474,250 |
| NPCC(U.S.) | 2,062,686 | 2,645,731 | 1,985,167 | 1,544,571 | 1,103,492 |
| SERC | –- | –- | –- | –- | –- |
| SPP | –- | –- | –- | –- | –- |
| WSCC(U.S.) | 4,327,789 | 4,075,034 | 5,675,033 | 5,269,122 | 7,522,414 |
| **Contiguous U.S.** | **8,540,116** | **8,855,877** | **10,654,632** | **7,591,951** | **9,146,710** |
| ASCC | * | * | * | * | * |
| Hawaii | –- | –- | –- | –- | –- |
| **U.S. Total** | **8,540,116** | **8,855,877** | **10,654,632** | **7,591,951** | **9,146,710** |
| To Canada | 7,923,488 | 3,254,289 | 9,805,465 | 6,523,283 | 7,992,289 |
| To Mexico | 616,628 | 989,867 | 849,167 | 1,068,668 | 1,154,421 |

* =Value less than 0.5.

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •Values identify point of entry or exit, but do not necessarily identify point of consumption. •These data reflect electricity exported to Canada and Mexico.

Source: Office of Fuels Programs, Fossil Energy, Form FE-781R, ''Annual Report of International Electric Export/Import Data.''

# 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 increasing 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 and 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. The primary objective of most DSM programs has been 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. Identifying the right mix of DSM options can be mutually beneficial to the utility, the consumer, and society. The utility can benefit from lowered costs of service, improved operating efficiency, reduced capital requirements, and enhanced consumer service. Consumers can benefit from reduced costs and improved value of service. Society can benefit from reduced emissions and the conservation of energy sources. With the changes that are occurring within the electric utility industry, there is a great deal of uncertainty about the direction of utility sponsored DSM programs. Some utilities are moving toward energy service companies, while other utilities are making no changes to their DSM 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 will vary significantly depending on their overall organization and market environment, strategic objectives, and system operating characteristics. DSM programs generally promote one of four basic objectives that differ in their intended effects on electricity use (measured in kilowatthours) and demand (measured in kilowatts). First, energy efficiency, or conservation, programs are aimed at reducing the energy used by specific end-use devices and systems through the promotion of high-efficiency equipment and building design, typically reducing energy consumption throughout many hours of the year. 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). Second, load management programs are aimed at reducing or shifting demand at certain critical times (such as summer or winter peak), and are focused on changing the timing of electricity demand. These program types usually have only a minor effect on the amount of annual electricity 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 direct control of the utility during a few peak-demand hours. Third, flexible load shape programs provide consumers a price signal or incentive to modify 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. Fourth, strategic load growth or electrification programs are designed to increase electricity consumption typically by building usage during valleys of low consumption or introducing new, efficient electrotechnologies. Such programs may facilitate the efficient operation of baseload generating units, reduce rates, and help customers meet environmental requirements, enhance product quality, or lower costs by replacing less efficient energy sources.

The energy savings and peak load reductions reported by electric utilities to EIA fall into one of six DSM program types.

**Energy Efficiency** - Energy efficiency programs are aimed at reducing the energy used by specific end-use devices and systems, typically without reducing the

level of energy services provided. These programs often target high-use seasons or times of day. While they reduce overall electricity consumption over many hours during the year, the largest impacts of these programs often coincide with periods of peak usage. 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, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motors and drive systems, and heat recovery systems. Energy efficiency programs frequently incorporate rebates, financing or other financial incentives for participation, rather than relying primarily on alternative rate structures as do some other program categories.

**Direct Load Control** - This category represents the consumer load that can be interrupted during the periods of peak load by direct control of the utility system operator. This type of control primarily involves residential consumers.

**Interruptible Load** - This category accounts for the consumer load that, in accordance with contractual arrangements, can be interrupted during periods of peak load either by the direct control of the utility system operator or by the action of the consumer at the direct request of the system operator. It usually affects large-volume commercial and industrial consumers.

**Other Load Management** - This category refers to programs other than direct load control and interruptible load that limit peak loads, shift peak load from on-peak to off-peak time periods, or encourage customers to respond to changes in the utility's cost of providing power. The category 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, or high-cost to low-cost periods, through the application of time-differentiated rates.

**Other Demand-Side Management Program** - This residual category captures the effects of DSM programs that cannot be meaningfully included in any of the other program categories. The energy effects attributable to this category represent the net effects of all the residual programs. Programs that promote consumer substitution of other energy types for electricity and self-generation of electricity for consumers' own use are included.[14]

**Load Building** - This category represents 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 includes programs that promote the substitution of electricity for other fuels.[15]

## *Planning and Selection of Programs*

The key elements of the DSM program planning and selection process are to identify and evaluate key consumer characteristics that influence acceptance and response to DSM programs and key utility considerations affecting resource requirements and the cost of alternative resource options. Among the consumer characteristics that influence a program's success are demographics, income, knowledge and awareness, attitude and motivation, discount rate, and price experience. External influences such as economic conditions, energy prices, technologies, regulation, and tax credits also influence consumer's decisions regarding fuel and appliance choices, appliance and equipment efficiency, and appliance 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.

To compare DSM programs to other demand- and supply-side resources, regulators have developed standardized benefit-cost tests. Five benefit-cost tests are widely used in planning to identify cost-effective DSM programs. For each test, the net present value and benefit-cost ratio can be determined. The present value equals total benefits of the program less total costs; the benefit-cost ratio is the ratio of total benefits to total costs. Based on these values, the utility can prioritize DSM programs to determine which, if any, should be implemented.

**The Utility Cost Test** measures the net benefits or costs of programs based on costs incurred by the utility and revenue requirements of the utility (i.e., the test excludes participant costs). It determines if the utility's cost for DSM programs is less than the avoided supply cost.

**The Participant Test** measures the quantifiable benefits and costs to consumers who participate in the DSM program. It attempts to answer whether the participant is better off with the DSM technology and likely to participate in future programs.

[14] Self-generation of electricity for consumers' use is included in the Other DSM category only to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories. Also, self-generation in the Other DSM category includes only that capacity for use by the consumer that is part of the utility's DSM program. Self-generation that is driven by market forces is excluded.

[15] Load building, although collected on the Form EIA-861, Schedule V, is not included in the discussion of data in this publication.

**The Rate Impact Measure Test** captures the present value impact on all consumers' average rates due to the DSM program. It evaluates whether average rates for consumers (including nonparticipants) will go up or down or remain unaffected.

**The Total Resource Cost Test** shows the net benefits or costs of a DSM program as a resource option based on the total costs of the program, including both participant and utility costs (the Societal Cost Test is a variant of this test that incorporates externalities and excludes tax credits). The Total Resources Cost Test determines if the total cost of DSM to participants and non-participants is less than the supply cost for an equivalent amount of capacity and energy.

**The Societal Test** takes the broadest point of view, including the total resource cost and external costs and benefits, such as environmental impacts. It determines if the total cost of the DSM program is less than the alternative supply cost (including environmental costs).

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- 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.[16] 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 national security costs associated with reliance on 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.[17]

## *Program Implementation*

Another component of DSM program development is the marketing plan to implement a package of cost-effective programs through customer education, direct contact, cooperation with trade ally (for example, building contractors and appliance dealers), advertising/promotion, alternative pricing, incentives, financing, and direct installation. The programs differ in the types of services offered to consumers. For example, general information programs attempt to inform consumers about DSM options through such mechanisms as brochures, bill stuffers, television and radio advertisements, and workshops. Direct installation programs involve installation of energy efficiency measures in the facilities of participating consumers by the utility or its contractors. These programs generally cover low-cost measures, such as water-heater wraps and compact fluorescent lamps. Energy audits provide information on the physical and operating characteristics of a building and its energy uses and processes. Audit services vary from simple walk-throughs to building management training programs and cite-specific process and efficiency evaluations. Incentive programs offer cash or noncash awards to manufacturers of energy efficient electric equipment, deliverers of energy products or services such as appliance and equipment dealers, building contractors, and architectural and engineering firms, or directly to consumers to encourage consumer participation in a DSM program and adoption of recommended measures. Appliance rebates and zero- or low-interest loans are common examples of incentive programs. Lastly, utilities offer alternative-rate programs, such as discounts or refunds on monthly electric bills, in return for consumer participation in programs designed to reduce peak demand or to modify the load shape.

Most DSM programs are aimed at specific subsets of the utility population, typically by consumer classes and market segments. For example, the residential sector is often subdivided by housing type (for example, single-unit, multi-unit, mobile home). Residential sector programs typically consider the relative similarity of end uses and consumption patterns to identify load-shape modification opportunities with relatively predictable outcomes. Because per-unit electricity consumption in the residential sector is less than that of the commercial and industrial sectors, residential DSM programs are usually designed to achieve high participation rates in order to significantly alter the load curve of the utility system.

Most commercial electricity consumption is for lighting, air conditioning, and space heating. However, the relative importance of the different end uses varies significantly across consumer types. Office buildings, retail establishments, schools, supermarkets, and restaurants exhibit distinctly different patterns of electricity consumption. Recently, utility-

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

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

sponsored efforts to develop DSM potential in the commercial sector have increased significantly, with program activities focusing on energy-management assistance, cool storage, lighting, heating and air conditioning, and water heating improvements.

DSM program development in the industrial sector has been slow compared to its development in the residential and commercial sectors. The wide variety of industrial processes use initially hindered the design of DSM programs tailored to the industrial sector. Utilities traditionally relied on alternative rate-design approaches, such as interruptible service and time-of-use rates to achieve DSM objectives in the industrial sector. Utilities have broadened their DSM approach to include incentive and financing programs for industrial lighting, thermal storage, electrotechnology, advanced motors and drive systems, compressed-air systems, and other process-energy uses that have the potential to meet energy-efficiency and load-management objectives. A number of utilities have also developed flexible custom measure programs that allow industrial energy users and utilities to work together to identify cost-effective measures.

## Monitor and Evaluate Programs

Electric utilities must rely on systematic measurement, statistical analysis, and engineering expertise to evaluate the operation and performance of DSM programs by verifying DSM results, assessing the effectiveness of the program, providing feedback on the results that are essential for future decisions about DSM programs. Utilities report DSM-program results in a number of ways, depending largely on the load modification objectives of their programs. For example, utilities interested in peak clipping typically measure program success in terms of total peak load reduction or its reduction per consumer. Utilities interested in reducing overall energy consumption measure both peak load reduction and total energy savings. When evaluating program success, utilities typically determine the level of load-and-energy reductions, program costs per unit of energy and/or demand savings, and program participation rates.

While the consumption of electricity can be measured in a variety of ways (such as monthly electric bills, special short-term metering, whole-building load-research data, or end-use load monitoring) the saving of electricity--the difference between actual consumption and what would have occurred in the absence of a DSM program--can only be estimated based on engineering data or statistical analysis.

The analytical procedures applied to estimate electricity and load changes involve a variety of techniques. These techniques include using engineering estimates to derive the energy-saving effect per installation of each energy-efficient device, monitoring electricity use for selected consumers before and after participation in a DSM activity, and contrasting the aggregated effects of DSM program participants and nonparticipants.

Evaluation and verification to determine whether DSM programs achieve their stated objectives are essential because (1) utilities are scheduled to invest billions of dollars in DSM programs, (2) utilities are counting on the saved electricity as one way to meet expected increases in future electricity demand, (3) State regulators are increasingly allowing utilities to collect financial incentives and recover cost revenues based on the results of DSM programs, (4) the results of conservation programs may be recognized for purposes of environmental compliance, and (5) utilities and regulators need to know what mix of DSM technologies and techniques yields the most cost-effective energy savings.[18]

As utility DSM budgets have grown, exceeding $2.4 billion in 1995, it has become increasingly important to know what DSM programs have accomplished. This has led to more sophisticated efforts to measure and evaluate an increased number of programs. Nevertheless, detailed impact and process evaluations have been completed on only a small fraction of all DSM programs. These evaluations vary with respect to the methodologies employed, the issues and types of programs studied, and the purposes for which evaluations were conducted. Because practices vary substantially from one utility to the next, it is difficult to generalize regarding the quality of the data supporting the estimates of energy savings and peak reductions reported to EIA or the extent to which such estimates have been subject to after-the-fact verification.[19]

## Data Sources

The data in the following tables were collected on Schedule V, "Demand-Side Management Information," of the 1995 Form EIA-861,"Annual Electric Utility Report." Schedule V collects utility information on actual and potential peak load reductions and energy savings for six program categories (Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building) by four major consumer sectors (residential, commercial, industrial, and other). Utilities provide information for the reporting year (1995) and the first and fifth forecast years (1996 and 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

[18] General Accounting Office, *Electricity Supply, Utility Demand-Side Management Programs Can Reduce Electricity Use,* GAO/RCED-92-13 (Washington, DC, October 1991).

[19] In 1993, for the first time, utilities provided information on the methodologies used to estimate and verify the energy savings and peak load reductions of their DSM programs.

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 three categories. If the cost can be tracked to a specific program category (energy efficiency, direct load control, etc.), 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 under the appropriate accounting category (administrative, marketing, monitoring and evaluation, or other). Total nonutility cost is also reported.

**Table 43. U.S. Electric Utility Demand Side Management Program Energy Savings, Actual and Potential Peak Load Reductions, and Cost, 1991 Through 1995**

| Item | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|
| **Energy Savings (million kilowatthours)**[1] | 24,848 | 35,563 | 45,294 | 52,483 | 57,421 |
| **Actual Peak Load Reductions (megawatts)**[1 2] | 15,619 | 17,204 | 23,069 | 25,001 | 29,561 |
| **Potential Peak Load Reductions (megawatts)**[1] | NA | 32,422 | 39,508 | 42,917 | 47,029 |
| **Cost (thousand dollars)**[3] | 1,803,773 | 2,348,094 | 2,743,533 | 2,715,657 | 2,421,284 |

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 in the following demand-side management program categories: energy efficiency, direct load control, interruptible load, other load management, other demand-side management; reflects 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 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.

NA=Data not available.

Notes: •Data for 1995 are preliminary; data for prior years are final. •Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours. •Data for 1995 for peak load growth (754,379 megawatts), energy sales (5,321,170 megawatthours), and cost ($46,922 (thousands)) attributable to Load Building programs are excluded.

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

**Table 44. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand–Side Management Program Category, 1991 Through 1995** (Megawatts)

| North American Electric Reliability Council Region and Hawaii | Total Actual Peak Load Reduction | Direct Load Control | Interruptible Load | Energy Efficiency, Other Load Management, and Other Demand-Side Management |
|---|---|---|---|---|
| | | | 1991 | |
| ECAR | 1,401 | 319 | 615 | 467 |
| ERCOT | 311 | 68 | 30 | 213 |
| MAAC | 1,484 | 573 | 667 | 244 |
| MAIN | 762 | 64 | 369 | 329 |
| MAPP(U.S.) | 1,424 | 902 | 305 | 217 |
| NPCC(U.S.) | 1,493 | 215 | 343 | 935 |
| SERC | 4,876 | 2,030 | 602 | 2,244 |
| SPP | 1,155 | 506 | 428 | 221 |
| WSCC(U.S.) | 2,668 | 414 | 287 | 1,967 |
| **Contiguous U.S.** | **15,574** | **5,091** | **3,646** | **6,837** |
| ASCC | 5 | 2 | 3 | 0 |
| Hawaii | 40 | 0 | 25 | 15 |
| **U.S. Total** | **15,619** | **5,093** | **3,674** | **6,852** |

See footnotes at end of table.

## Table 44. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand–Side Management Program

Category, 1991 Through 1995 (Continued) (Megawatts)

| | Total Actual Peak Load Reduction | Direct Load Control | Interruptible Load | Energy Efficiency | Other Load Management | Other Demand-Side Management |
|---|---|---|---|---|---|---|
| | | | **1992** | | | |
| ECAR | 661 | 128 | 49 | 379 | 101 | 4 |
| ERCOT | 592 | 22 | 131 | 369 | 68 | 2 |
| MAAC | 1,677 | 631 | 317 | 216 | 512 | 0 |
| MAIN | 840 | 32 | 466 | 323 | 20 | * |
| MAPP(U.S.) | 1,542 | 655 | 420 | 270 | 190 | 9 |
| NPCC(U.S.) | 1,796 | 169 | 323 | 1,257 | 48 | * |
| SERC | 5,559 | 1,582 | 684 | 2,638 | 487 | 168 |
| SPP | 624 | 370 | 117 | 85 | 6 | 46 |
| WSCC(U.S.) | 3,902 | 188 | 1,074 | 2,351 | 237 | 52 |
| **Contiguous U.S.** | **17,194** | **3,777** | **3,579** | **7,889** | **1,669** | **281** |
| ASCC | 7 | 2 | 0 | * | 4 | 0 |
| Hawaii | 4 | 0 | 0 | 1 | 3 | 0 |
| **U.S. Total** | **17,204** | **3,779** | **3,579** | **7,890** | **1,676** | **281** |
| | | | **1993** | | | |
| ECAR | 1,671 | 179 | 773 | 573 | 115 | 31 |
| ERCOT | 1,414 | 42 | 114 | 949 | 291 | 17 |
| MAAC | 1,493 | 329 | 516 | 301 | 340 | 7 |
| MAIN | 844 | 60 | 247 | 494 | 39 | 4 |
| MAPP(U.S.) | 2,121 | 793 | 632 | 413 | 270 | 12 |
| NPCC(U.S.) | 1,968 | 201 | 228 | 1,520 | 18 | * |
| SERC | 8,447 | 1,770 | 2,792 | 3,329 | 439 | 115 |
| SPP | 889 | 395 | 323 | 111 | 36 | 23 |
| WSCC(U.S.) | 4,210 | 183 | 1,003 | 2,671 | 250 | 104 |
| **Contiguous U.S.** | **23,597** | **3,953** | **6,628** | **10,363** | **1,799** | **315** |
| ASCC | 7 | 2 | 0 | * | 4 | 0 |
| Hawaii | 5 | 0 | 0 | 5 | 0 | 0 |
| **U.S. Total** | **23,069** | **3,955** | **6,628** | **10,368** | **1,803** | **315** |
| | | | **1994** | | | |
| ECAR | 1,583 | 200 | 634 | 631 | 103 | 15 |
| ERCOT | 1,838 | 20 | 77 | 1,420 | 301 | 19 |
| MAAC | 1,803 | 353 | 676 | 414 | 356 | 4 |
| MAIN | 1,177 | 26 | 523 | 576 | 46 | 6 |
| MAPP(U.S.) | 2,319 | 933 | 656 | 505 | 211 | 14 |
| NPCC(U.S.) | 2,261 | 90 | 194 | 1,959 | 16 | 1 |
| SERC | 8,562 | 2,118 | 2,736 | 3,023 | 494 | 192 |
| SPP | 855 | 232 | 249 | 177 | 185 | 13 |
| WSCC(U.S.) | 4,584 | 203 | 998 | 2,950 | 376 | 57 |
| **Contiguous U.S.** | **24,983** | **4,176** | **6,743** | **11,655** | **2,088** | **321** |
| ASCC | 8 | 2 | 0 | 1 | 0 | 4 |
| Hawaii | 10 | 0 | 0 | 6 | 4 | 0 |
| **U.S. Total** | **25,001** | **4,179** | **6,743** | **11,662** | **2,092** | **326** |
| | | | **1995** | | | |
| ECAR | 2,458 | 364 | 1,088 | 839 | 107 | 60 |
| ERCOT | 1,873 | 22 | 94 | 1,447 | 306 | 4 |
| MAAC | 2,110 | 311 | 752 | 671 | 362 | 13 |
| MAIN | 1,254 | 23 | 505 | 658 | 59 | 9 |
| MAPP(U.S.) | 3,373 | 1,284 | 1,198 | 661 | 215 | 15 |
| NPCC(U.S.) | 2,594 | 87 | 301 | 2,178 | 28 | * |
| SERC | 10,103 | 2,928 | 3,314 | 3,134 | 495 | 232 |
| SPP | 747 | 153 | 203 | 200 | 172 | 19 |
| WSCC(U.S.) | 5,028 | 178 | 947 | 3,415 | 424 | 63 |
| **Contiguous U.S.** | **29,539** | **5,350** | **8,401** | **13,203** | **2,168** | **416** |
| ASCC | 9 | 3 | 0 | 2 | 0 | 5 |
| Hawaii | 13 | 0 | 0 | 7 | 0 | 6 |
| **U.S. Total** | **29,561** | **5,353** | **8,401** | **13,212** | **2,168** | **426** |

Notes: •Data for 1995 are preliminary; data for prior years are final. •Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours. •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 45. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Program Category, 1995

| 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] | 13,212 | 13,212 | 55,328 |
| Direct Load Control | 5,353 | 9,037 | 133 |
| Interruptible Load | 8,401 | 21,820 | 434 |
| Other Load Management[6] | 2,168 | 2,485 | 297 |
| Other Demand-Side Management[7] | 426 | 476 | 1,229 |
| **U.S. Total** | 29,561 | 47,029 | 57,421 |
| | **Incremental Effects[8]** | | |
| **Large Utilities[4]** | | | |
| Energy Efficiency[5] | 1,561 | 1,561 | 7,901 |
| Direct Load Control | 552 | 958 | 12 |
| Interruptible Load | 2,209 | 3,574 | 56 |
| Other Load Management[6] | 246 | 355 | 60 |
| Other Demand-Side Management[7] | 32 | 43 | 193 |
| **Small Utilities[9]** | | | |
| Energy Efficiency[5] | 7 | 7 | 16 |
| Direct Load Control | 20 | 28 | 2 |
| Interruptible Load | 4 | 6 | 1 |
| Other Load Management[6] | 3 | 5 | * |
| Other Demand-Side Management[7] | 2 | 2 | * |
| **U.S. Total** | 4,636 | 6,539 | 8,242 |

1 Represents the sum of the actual peak load reductions attributable to direct load control, interruptible load, energy efficiency, other load management, and other demand-side management.

2 Represents the sum of the potential peak load reductions attributable to direct load control, interruptible load, other load management, other demand-side 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 120,000 megawatthours.

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 Refers to programs other than direct load control and interruptible load that limit or shift load from on-peak to off-peak time periods, including 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, load limiting devices in energy management systems, and programs that aggressively promote time-of-use rates and other innovative rates such as real time pricing.

7 Includes programs that promote consumer's substitution of electricity by other energy types and self-generation of electricity for consumer use. Self-generation is included only to the extent that it is not accounted for as backup generation in other load management or interruptible load categories, used by the consumer, and initiated by the electric utility (i.e., not a consumer response driven by market forces).

8 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.

9 Refers to electric utilities with sales to ultimate consumers and sales for resale less than 120,000 megawatthours.

* =Value less than 0.5.

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

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

## Table 46. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Sector, 1995

| Sector | Actual Peak Load Reductions[1] (megawatts) | Potential Peak Load Reductions[2] (megawatts) | Energy Savings (million kilowatthours) |
|---|---|---|---|
| | **Annual Effects[3]** | | |
| **Large Utilities[4]** | | | |
| Residential | 10,930 | 14,047 | 20,253 |
| Commercial | 8,054 | 11,495 | 26,187 |
| Industrial | 10,033 | 20,715 | 9,620 |
| Other | 545 | 772 | 1,360 |
| **U.S. Total** | 29,561 | 47,029 | 57,421 |
| | **Incremental Effects[5]** | | |
| **Large Utilities[4]** | | | |
| Residential | 860 | 1,231 | 1,630 |
| Commercial | 1,176 | 1,697 | 4,594 |
| Industrial | 2,426 | 3,368 | 1,678 |
| Other | 139 | 195 | 320 |
| **Small Utilities[6]** | | | |
| Residential | 20 | 27 | 9 |
| Commercial | 10 | 13 | 5 |
| Industrial | 4 | 6 | 5 |
| Other | 2 | 2 | 2 |
| **U.S. Total** | 4,636 | 6,539 | 8,242 |

1 Represents the sum of the actual peak load reductions attributable to direct load control, interruptible load, energy efficiency, other load management, and other demand-side management.

2 Represents the sum of the potential peak load reductions attributable to direct load control, interruptible load, other load management, other demand-side 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 1993. Included are new and existing participants in existing programs (those implemented in prior years that were in place during 1993) and all participants in new programs (those implemented during 1993).

4 Refers to electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours.

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

6 Refers to electric utilities with sales to ultimate consumers and sales for resale less than 120,000 megawatthours.

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

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

## Table 47. U.S. Electric Utility Potential Peak Load Reductions by Direct Load Control and Interruptible Load and by North American Electric Reliability Council Region and Hawaii, Selected Years

(Megawatts)

| North American Electric Reliability Council Region and Hawaii | Historical Reductions | | | | | Projected Reductions | |
|---|---|---|---|---|---|---|---|
| | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 2000 |
| | | | | **Direct Load Control** | | | |
| ECAR | 337 | 222 | 227 | 247 | 413 | 447 | 655 |
| ERCOT | 68 | 121 | 164 | 202 | 215 | 208 | 220 |
| MAAC | 756 | 933 | 1,033 | 1,260 | 1,296 | 1,221 | 1,474 |
| MAIN | 64 | 147 | 190 | 211 | 169 | 234 | 506 |
| MAPP(U.S.) | 1,020 | 1,054 | 1,252 | 1,368 | 1,876 | 1,948 | 2,277 |
| NPCC(U.S.) | 222 | 188 | 219 | 104 | 111 | 100 | 107 |
| SERC | 3,271 | 3,814 | 3,950 | 4,339 | 4,007 | 4,149 | 4,951 |
| SPP | 569 | 533 | 615 | 434 | 321 | 329 | 348 |
| WSCC(U.S.) | 731 | 612 | 612 | 724 | 627 | 627 | 695 |
| **Contiguous U.S.** | **7,038** | **7,624** | **8,263** | **8,888** | **9,034** | **9,264** | **11,233** |
| ASCC | 2 | 2 | 2 | 2 | 3 | 3 | 3 |
| Hawaii | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **U.S. Total** | **7,040** | **7,626** | **8,266** | **8,890** | **9,037** | **9,267** | **11,237** |
| | | | | **Interruptible Load** | | | |
| ECAR | 1,036 | 1,214 | 1,456 | 1,643 | 2,270 | 2,581 | 2,653 |
| ERCOT | 1,293 | 1,736 | 1,968 | 1,803 | 1,918 | 2,019 | 2,233 |
| MAAC | 724 | 838 | 1,152 | 1,614 | 1,781 | 1,736 | 2,078 |
| MAIN | 735 | 867 | 803 | 1,116 | 1,220 | 1,331 | 1,431 |
| MAPP(U.S.) | 682 | 789 | 823 | 973 | 1,326 | 1,360 | 1,674 |
| NPCC(U.S.) | 379 | 371 | 358 | 245 | 349 | 258 | 349 |
| SERC | 2,759 | 4,204 | 6,624 | 6,816 | 7,621 | 7,625 | 8,030 |
| SPP | 813 | 1,181 | 2,041 | 2,004 | 1,964 | 2,130 | 2,497 |
| WSCC(U.S.) | 3,038 | 3,353 | 2,997 | 3,167 | 3,371 | 3,157 | 3,093 |
| **Contiguous U.S.** | **11,459** | **14,553** | **18,222** | **19,380** | **21,820** | **22,198** | **24,039** |
| ASCC | 3 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hawaii | 25 | 13 | 12 | 4 | 0 | 4 | 4 |
| **U.S. Total** | **11,487** | **14,566** | **18,235** | **19,384** | **21,820** | **22,202** | **24,043** |

Notes: •Data for 1995, 1996, and 2000 are preliminary; data for prior years 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 120,000 megawatthours. •Program participants include new and existing participants in existing programs (those implemented in prior years that are in place during the reported year) and all participants in new programs (those implemented during the reported year).

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

## Table 48. U.S. Electric Utility Demand-Side Management Energy Savings by North American Electric Reliability Council Region and Hawaii, Selected Years

(Million Kilowatthours)

| North American Electric Reliability Council Region and Hawaii | Historical Savings | | | | | Projected Savings | |
|---|---|---|---|---|---|---|---|
| | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 2000 |
| ECAR | 1,072 | 1,129 | 1,779 | 2,237 | 3,030 | 3,704 | 5,406 |
| ERCOT | 393 | 1,013 | 2,288 | 3,739 | 3,757 | 3,919 | 4,582 |
| MAAC | 549 | 954 | 1,150 | 1,820 | 3,000 | 3,866 | 6,471 |
| MAIN | 1,081 | 1,212 | 2,125 | 2,453 | 2,732 | 3,214 | 4,256 |
| MAPP(U.S.) | 494 | 940 | 1,581 | 1,883 | 2,506 | 3,120 | 5,180 |
| NPCC(U.S.) | 3,657 | 5,049 | 6,769 | 8,422 | 9,694 | 10,589 | 13,200 |
| SERC | 7,481 | 10,492 | 11,264 | 11,768 | 10,143 | 11,068 | 14,822 |
| SPP | 156 | 273 | 365 | 492 | 335 | 345 | 435 |
| WSCC(U.S.) | 9,801 | 14,491 | 17,954 | 19,634 | 22,178 | 23,240 | 24,660 |
| **Contiguous U.S.** | **24,684** | **35,554** | **45,275** | **52,449** | **57,374** | **63,064** | **79,010** |
| ASCC | 0 | * | 2 | 3 | 4 | 5 | 6 |
| Hawaii | 164 | 9 | 17 | 31 | 43 | 70 | 324 |
| **U.S. Total** | **24,848** | **35,563** | **45,294** | **52,483** | **57,421** | **63,138** | **79,340** |

* =Value less than 0.5.

Notes: •Data for 1995, 1996, and 2000 are preliminary; data for prior years 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 120,000 megawatthours.

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

## Table 49. U.S. Electric Utility Demand-Side Management Cost by North American Electric Reliability Council Region and Hawaii, Selected Years

(Thousand Dollars)

| North American Electric Reliability Council Region and Hawaii | Existing | | | | | Projected | |
|---|---|---|---|---|---|---|---|
| | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 2000 |
| ECAR | 36,534 | 130,903 | 187,137 | 137,118 | 138,910 | 121,684 | 94,445 |
| ERCOT | 52,701 | 55,675 | 62,533 | 69,538 | 70,421 | 61,557 | 57,341 |
| MAAC | 131,103 | 178,420 | 262,111 | 305,190 | 300,347 | 282,717 | 342,329 |
| MAIN | 93,316 | 133,610 | 128,607 | 96,253 | 78,004 | 78,202 | 98,878 |
| MAPP(U.S.) | 56,082 | 85,021 | 103,185 | 138,256 | 158,971 | 125,983 | 149,347 |
| NPCC(U.S.) | 511,632 | 542,222 | 565,145 | 462,668 | 346,716 | 323,480 | 268,684 |
| SERC | 643,081 | 510,489 | 643,081 | 684,647 | 681,161 | 667,842 | 782,813 |
| SPP | 24,652 | 30,927 | 33,376 | 28,626 | 26,546 | 25,944 | 26,668 |
| WSCC(U.S.) | 565,998 | 679,752 | 756,947 | 792,387 | 619,575 | 543,711 | 411,215 |
| **Contiguous U.S.** | **1,803,769** | **2,347,019** | **2,741,832** | **2,714,726** | **2,420,651** | **2,231,120** | **2,231,720** |
| ASCC | 0 | 315 | 419 | 386 | 633 | 789 | 993 |
| Hawaii | 4 | 760 | 1,282 | 588 | 0 | 11,104 | 25,980 |
| **Total Cost**[1] | **1,803,773** | **2,348,094** | **2,743,533** | **2,715,657** | **2,421,284** | **2,243,013** | **2,258,693** |

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 for 1995, 1996, and 2000 are preliminary; data for prior years 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 120,000 megawatthours. •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. •Electric utility load building cost ($46,922 (thousands) in 1995), ($50,920 (thousands) in 1996), ($43,932 (thousands) in 2000) and utility earned incentives are excluded.

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

## Table 50. U.S. Electric Utility Demand-Side Management Direct and Indirect Cost, Selected Years

(Thousand Dollars)

| Program | Historical Cost | Projected Costs | |
|---|---|---|---|
| | 1995 | 1996 | 2000 |
| **Total Direct Cost**[1] | **2,004,942** | **1,860,941** | **1,825,207** |
| Energy Efficiency | 1,408,542 | 1,254,712 | 1,174,672 |
| Direct Load Control | 319,326 | 329,724 | 384,608 |
| Interruptible Load | 201,801 | 211,266 | 199,199 |
| Other Load Management | 56,631 | 52,265 | 50,906 |
| Other Demand-Side Management | 18,642 | 12,974 | 15,822 |
| **Total Indirect Cost**[2] | **416,342** | **382,072** | **433,306** |
| Administrative | 178,020 | 116,869 | 119,897 |
| Marketing | 63,784 | 75,652 | 81,971 |
| Monitoring and Evaluation | 59,235 | 61,694 | 57,015 |
| Other[3] | 115,303 | 127,857 | 174,603 |
| **Total Cost**[4] | **2,421,284** | **2,243,013** | **2,258,693** |

1 Reflects electric utility cost incurred during the year that are identified with one of the demand-side program categories. Load building cost ($46,922 (thousands) for 1995, $50,920 (thousands) for 1996, and $43,932 (thousands) for 2000) are excluded.

2 Reflects electric cost incurred during the year that are not meaningfully identified with any particular demand-side management program category, but can be attributable to one of several accounting cost categories.

3 Includes the indirect costs of demand-side management programs that cannot be meaningfully included in any of the other cost categories, including costs incurred in the research and development of demand-side management technologies.

4 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 for 1995, 1996, and 2000 are preliminary. •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 120,000 megawatthours. •Nonutility cost ($470,164 (thousands) in 1995, $320,579 (thousands) in 1996, and $311,669 (thousands) in 2000) are excluded.

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

## Table 51. Number of U.S. Electric Utilities with Demand-Side Management Energy Efficiency Programs by End Uses and Program Types by Sector, 1995

| Item | Residential | Commercial | Industrial |
|---|---|---|---|
| **End Uses** | | | |
| Heating System | 367 | 244 | 133 |
| Cooling System | 384 | 280 | 164 |
| Water Heating | 421 | 213 | 149 |
| Lighting | 243 | 285 | 223 |
| Building Shell | 219 | 134 | 100 |
| New Construction | 244 | 159 | 114 |
| Appliances | 178 | 86 | 51 |
| Motors | -- | 177 | 191 |
| Process Heating | -- | 51 | 96 |
| Electrolytics | -- | 9 | 24 |
| Other System | 61 | 34 | 44 |
| **Program Types** | | | |
| Energy Audits | 387 | 336 | 251 |
| Rebates | 385 | 275 | 194 |
| Loaning | 177 | 108 | 74 |
| Other Incentives[1] | 143 | 99 | 81 |
| Other | 141 | 99 | 74 |

1 This category reflects 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 demand-side management program and adoption of recommended measures.

Notes: •Data are preliminary. •Data represent the total number of electric utilities that focus energy efficiency activities on specific end uses and program types.

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 1991 through 1995. These data are aggregated at the U.S. Census division level. Since nonutility data 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." 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-867" 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. During the 1970's, however, 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.

In the late 1970's, changing economic conditions and legislation made nonutility generation attractive again for many industrial facilities and power project developers. In addition, 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. A nonutility power producing facility seeking to establish an interconnected operation with an electric utility 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.

In the 1970's, inflation, the energy crises, environmental concerns, and the rising costs of nuclear power raised electricity rates and reduced investment in new capacity. These factors led to a re-examination of alternatives such as nonutility electric power, which prompted the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978. Congress acted to relieve a nationwide energy crisis by enacting the National Energy Act of 1978, which encompassed 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 utility 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. The QF's include certain cogenerators, small power producers, and other nonutility generators. 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,[20] 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 utility's 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.

The Energy Policy Act of 1992 (EPACT) amended the Public Utility Holding Company Act (PUHCA) of 1935. PUHCA was designed to discourage holding companies from structuring their operations in ways that would prevent effective State regulation.

These are provisions of EPACT that are potentially affecting the nonutility industry. The creation of exempt wholesale generators (EWG's), corporate entities that are engaged exclusively in the business of wholesale electric generation and that are exempt from corporate organizational restrictions under PUHCA. Entities that are currently subject to PUHCA (registered holding companies and exempt utility holding companies) and entities that are not currently subject to PUHCA (nonutilities and non-holding company utilities) are permitted to own EWG's without limitation. Registered holding companies, must obtain approval from the Securities Exchange Commission to finance EWG's and service sales and construction contracts involving EWG's. The EPACT removes obstacles to wholesale power competition in the PUHCA by allowing both utilities and nonutilities to form EWG's without triggering the restrictions of PUHCA.

Allowing FERC to order upon application the wholesale, but not retail, transmission access on a case-by-case basis and transmission service by utilities, subject to certain protection.

The establishment of a program for providing Federal support on a competitive basis for renewable energy technologies. It also expands the program to promote the export of these renewable energy technologies to emerging markets in developing countries.

## Recent Legislative and Regulatory Activities

Recent government activity that will affect nonutility power producers are largely motivated by the EPACT electricity provisions, the FERC and several States have been working to develop open-access transmission systems, restructure the wholesale power generation market, and reform the ratemaking process. However, regulators are moving cautiously until the competitive effects of changes in utility cost structure and business practices are thoroughly studied. For example, the pricing provisions in wholesale power supply and transmission service contracts are undergoing review as the electricity industry moves closer to a market-based pricing regime. Artificial market support mechanisms, such as PURPA's avoided cost and guaranteed market provisions, are being reviewed as well.

In April of 1996, FERC issued two notable Federal actions to foster competition. These actions were the Final Rules and a notice of proposed rulemaking (NOPR). *Open Access Non-discriminatory Transmission Services by Public Utilities* (Docket No. RM95-8-000) or Order No. 888, and *Open Access Same-time Information System and Standards of Conduct* (Docket No. RM95-9-000) or Order No. 889. The Order 888 would require that all utilities file open access transmision tariffs for wholesale electricity transmission services. These services would have to be nondiscriminatory in the sense that terms and conditions for service were comparable to those available to utilities. The Order 889 requires jurisdictional utilities that own or operate transmission facilities to establish electronic to systems to share information about the available transmission capacity. It also established a standard of conduct for utilities. The NOPR issued by FERC proposes implementation of new electronic systems for utilities to use in reserving capacity on its and other companies' transmission systems.

PURPA is under review for streamlining or repeal of certain key provisions. The FERC issued a Final Rule in January 1995 that modified requirements for QF determination.[21] Key modifications included (1) allowing facilities to meet operating and efficiency standards on a 12-month basis (rather than calendar-year basis) to account for startup difficulties, (2) clarifying the "sequential-use-of energy" requirement[22], (3) removing the 80-megawatt size limitation for qualifying Small Power Producers (a temporary removal of the limitation was instituted by Congress in 1991), and (4) streamlining the QF determination process for facilities that use waste energy inputs. At the legislative level, a bill was introduced before the U.S. Senate that repeals Section 210 of PURPA. Known as the *Electric Utility Ratepayer Act* (S.708), the bill would eliminate the requirement that utilities must offer to purchase power from QF's. Proponents

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

[21] Federal Energy Regulatory Commission, Order 575, "Streamlining of Regulations Pertaining to Parts II and III of the Federal Power Act and the Public Utility Regulatory Policies Act of 1978," January 13, 1995.

[22] To meet FERC's "sequential energy" requirement, at least a portion of the waste heat from bottoming cycle cogenerators must be used to generate electricity. For topping cycle cogenerators, at least a portion of the waste heat from electricity production must be employed for a useful thermal purpose.

of the bill argue that the QF power purchase mandate is anticompetitive and costly. Opponents of the bill maintain that the mandate is a necessary check against utility monopoly power. *The Electricity Competition Act of 1996 (S.1526)* would require states to implement retail competition by 2010, grant FERC authority to permit recovery of all stranded costs, and repeal PURPA Section 210. House legislation *H.R. 2562, The Ratepayer Protection Act* would repeal Section 210 of PURPA and require FERC to issue a regulation to "assure that no utility shall be required directly or indirectly to absorb the costs associated with purchases from a qualifying facility. " The provision does not specifically indicate whether any regulation assuring recovering of qualifying facility cost would be limited to the term of the contract between the customer and the utility.

State public service commissions (PUC's) are coping with new regulatory responsibilities resulting from various EPACT provisions. New standards have been established, or are now being considered, for addressing jurisdictional responsibility for wholesale power market transactions. For the nonutility power market, an issue has been whether PUC's should intervene in disputes involving negotiated wholesale power purchases. Other new regulatory responsibilities include oversight of EWG's and the reevaluation of power purchase, supply, and demand-side management practices.

Regulators are also investigating ways to mitigate the adverse financial impacts on utilities' regulated assets caused by competition, while at the same time providing consumers with lower-cost power purchase alternatives. Among the options advanced by PUC's are incentive rates for deferring cogeneration or bypass by industrial customers, performance-based rates (price-cap and other flexible pricing plans), approval of utility-operated, on-site industrial power generation projects, and allowing independent power producers to repower existing utility generating plants.

## 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 both electric power and another form of useful energy. The technology selected depends on the requirement for processed steam. Cogenerating technologies 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 15), 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 15 represent most topping-cycle facilities.

In a bottoming-cycle system (Figure 16), 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 other 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 and 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 concen-

tration 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 heat 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 site or access to transmission.

## 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. 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 firms are also 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 on economic conditions. A nonutility power producer with many options as to fuel choice has a great economic advantage over a producer tied to only one fuel source.

## Data Sources

Summary statistics on nonutility capacity, generation, sales, and emissions in the United States are provided in the following tables. All data are final. These data were obtained from the Form EIA-867, “Annual Nonutility Power Producer Report.” The Form EIA-867 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 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. Data on planned nonutility capacity additions as of December 31, 1995, are presented by energy source in Figure 10. These data represent all nonutility planned generating facilities that meet one or more of the criteria defined earlier.

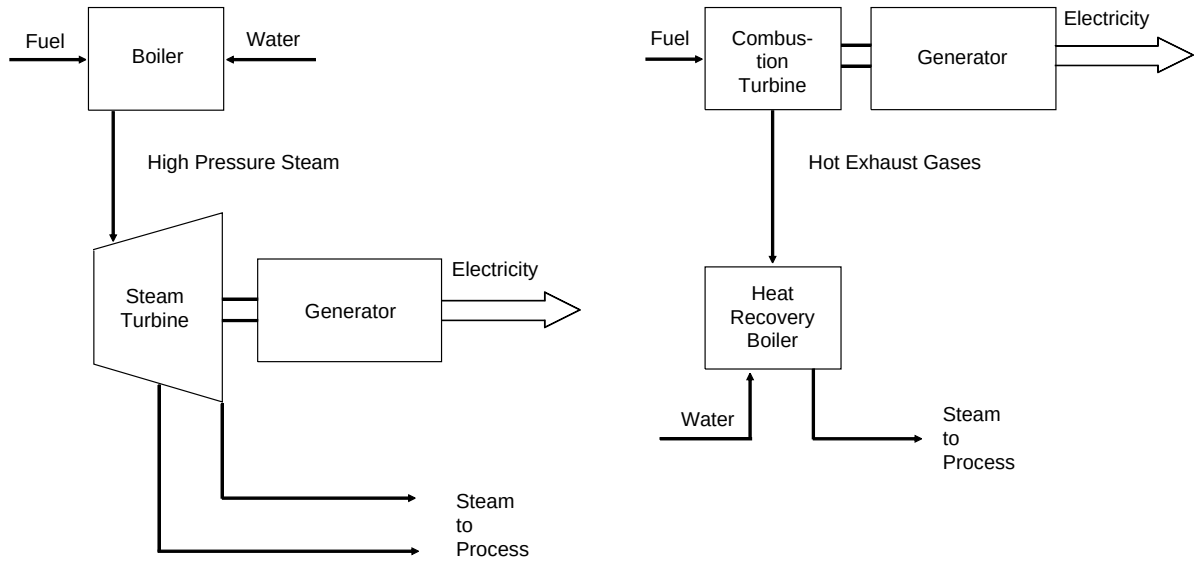
Some nonutility power producers of 1 or more megawatts use only fossil fuels; some use only renewable energy; and some use a combination of both fossil fuels and renewable energy sources. Although the majority of nonutility power producers generate electric power using fossil energy, those using renewable 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 52, 54, 55, 58 and 59 include hydrogen, sulfur, batteries, chemicals, fish oil and spent sulfite liquor.

The number of facilities shown for 1995 includes operational facilities in 1994 and new facilities or planned facilities that became operational during that year.

The total capacity for 1991 through 1995 (Table 52) 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 and out of service represented 7 percent of the total nonutility generating capacity in 1995.

**Figure 15. Two Topping-Cycle Plant Configurations**

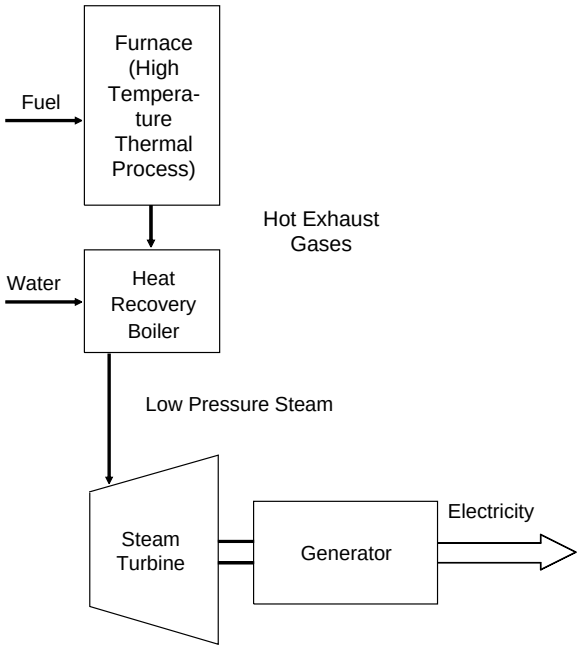



1. A boiler produces steam to power a turbine-generator to produce electricity. The turbine steam leaving the turbine is used in thermal applications such as space heating or food preparation.

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 16. Bottoming-Cycle Plant Configuration**




A furnace is used in a smelting or forming process. A waste-heat recovery boiler recaptures the unused energy and uses it to produce steam to drive a steam turbine generator to produce electricity.

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

## Table 52. Summary Statistics for U.S. Nonutility Power Producers, 1991 Through 1995

| Item | 1991 | 1992 | 1993 | 1994 | | 1995 | |
|---|---|---|---|---|---|---|---|
| | 5 Megawatts or More | | | 1 Megawatt or More | 5 Megawatts or More | 1 Megawatt or More | 5 Megawatts or More |
| **Installed Capacity (megawatts)** | **48,171** | **55,163** | **59,055** | **68,461** | **66,633** | **70,254** | **68,460** |
| Coal[1] | 7,291 | 8,443 | 9,712 | 10,372 | 10,322 | 10,454 | 10,397 |
| Petroleum[2] | 1,207 | 1,579 | 1,869 | 2,262 | 2,061 | 2,358 | 2,179 |
| Natural Gas[3] | 20,259 | 21,104 | 23,009 | 26,925 | 26,454 | 28,055 | 27,572 |
| Other Gas[4] | — | — | — | 1,130 | 1,122 | 1,217 | 1,197 |
| Petroleum/Natural Gas (Combined) | 5,049 | 8,354 | 8,377 | 9,820 | 9,667 | 10,479 | 10,340 |
| Hydroelectric | 1,587 | 2,133 | 2,173 | 3,364 | 2,783 | 3,399 | 2,832 |
| Geothermal | 1,048 | 1,243 | 1,307 | 1,335 | 1,324 | 1,295 | 1,284 |
| Solar | 360 | 360 | 360 | 354 | 354 | 354 | 354 |
| Wind | 1,652 | 1,786 | 1,775 | 1,737 | 1,700 | 1,723 | 1,691 |
| Wood[5] | 6,580 | 6,735 | 6,983 | 7,416 | 7,354 | 6,945 | 6,887 |
| Waste[6] | 2,627 | 2,805 | 2,910 | 3,150 | 2,900 | 3,402 | 3,160 |
| Nuclear[7] | 20 | 20 | 20 | — | — | — | — |
| Other[8] | 491 | 602 | 562 | 597 | 593 | 574 | 567 |
| **Gross Generation (million kilowatthours)** | **248,448** | **289,856** | **318,843** | **354,925** | **348,189** | **374,438** | **367,544** |
| Coal[1] | 40,587 | 47,160 | 53,166 | 59,035 | 58,839 | 57,668 | 57,485 |
| Petroleum[2] | 7,814 | 10,692 | 13,089 | 15,069 | 14,751 | 16,987 | 16,674 |
| Natural Gas[3] | 131,340 | 156,317 | 171,765 | 179,735 | 177,058 | 196,465 | 193,826 |
| Other Gas[4] | — | — | — | 12,480 | 12,441 | 13,867 | 13,771 |
| Hydroelectric | 6,243 | 7,611 | 9,583 | 13,227 | 11,293 | 14,774 | 12,740 |
| Geothermal | 7,651 | 8,533 | 9,704 | 10,122 | 10,080 | 9,912 | 9,872 |
| Solar | 779 | 746 | 897 | 824 | 824 | 824 | 824 |
| Wind | 2,606 | 2,872 | 2,999 | 3,482 | 3,424 | 3,185 | 3,140 |
| Wood[5] | 33,785 | 36,024 | 37,206 | 38,595 | 38,395 | 36,961 | 36,804 |
| Waste[6] | 13,956 | 16,330 | 17,187 | 18,797 | 17,532 | 20,014 | 18,645 |
| Nuclear[7] | 80 | 67 | 78 | 54 | 54 | — | — |
| Other[8] | 3,609 | 3,504 | 3,169 | 3,507 | 3,496 | 3,780 | 3,763 |
| **Consumption** | | | | | | | |
| Coal (Thousand short tons) | 38,113 | 44,132 | 47,827 | 52,261 | 51,731 | 47,849 | 47,277 |
| Petroleum (Thousand barrels)[9] | 27,274 | 30,219 | 35,390 | 40,460 | 38,521 | 39,075 | 36,462 |
| Natural Gas (Million cubic feet) | 1,569,713 | 1,791,576 | 1,968,875 | 2,149,246 | 2,094,964 | 2,311,187 | 2,224,755 |
| Other Gas (Million cubic feet)[10] | 1,364,353 | 1,581,870 | 1,672,852 | 1,586,185 | 1,583,190 | 1,604,427 | 1,591,900 |
| **Supply and Disposition (million kilowatthours)** | | | | | | | |
| Gross Generation | 248,448 | 289,856 | 318,843 | 354,925 | 348,189 | 374,438 | 367,544 |
| Receipts[11] | 68,264 | 76,198 | 77,378 | 94,166 | 83,476 | 89,919 | 81,300 |
| Deliveries to Utilities[12] | 129,118 | 161,360 | 184,266 | 204,688 | 201,398 | 216,502 | 212,961 |
| Deliveries to Other End Users[13] | 11,419 | 10,476 | 15,176 | 17,626 | 17,033 | 15,548 | 15,153 |
| Facility Use | 176,175 | 194,218 | 196,780 | 226,777 | 213,235 | 232,308 | 220,730 |

1 Includes coal, anthracite culm, coke breeze, fine coal and coal waste.
2 Includes municipal solid waste, agricultural waste, straw, tires, landfill gases, tall oil, digester gas and other waste.
3 Includes butane, ethane, propane, waste heat, and waste gases for years 1991-1993. Includes waste heat and waste gases for year 1994 and 1995.
4 Includes butane, ethane, propane, and other gases. Data not available for years 1991-1993.
5 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge.
6 Includes municipal solid waste, agricultural waste, straw, tires, landfill gases, tall oil, digester gas and other waste.
7 Nuclear reactor and generator at Argonne National Laboratory used primarily for research and development in testing reactor fuels as well as for training. The generation from the unit is used for internal consumption.
8 Includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
9 Does not include petroleum coke consumption of 4,740 thousand short tons for 1994 and 4,188 for 1995.
10 Includes butane, ethane, propane, and other gases.
11 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
12 Includes sales, interchanges, and exchanges of electric energy with utilities.
13 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-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. In addition, since the frame for the Form EIA-867 is derived from utility surveys the Form EIA-867 universe lags 1 year.

NA = Not available.

Notes: •Data for the above years are final. •Totals may not equal sum of components because of independent rounding. •Data for 1992 for 5 megawatt or more was incorrectly stated. The data has been changed to reflect these changes. •Percent change is calculated before rounding. •See the Technical Notes for the methodology for allocating capacity and generation by energy sources, respectively.

Source: Energy Information Administration, (EIA) Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 53. Installed Capacity at U.S. Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Sources, and Census Division, 1991 Through 1995

(Megawatts)

| Census Division | Fossil Fuels[1] | Renewables/ Other/ Nuclear[2] | Both Fossil Fuels and Renewables/ Other/ Nuclear |
|---|---|---|---|
| | **1991 (5 Megawatts or More)** | | |
| New England | 1,842 | 1,180 | 834 |
| Middle Atlantic | 3,690 | 821 | 429 |
| East North Central | 3,833 | 240 | 959 |
| West North Central | 882 | 105 | 116 |
| South Atlantic | 3,597 | 1,250 | 2,416 |
| East South Central | 455 | 162 | 872 |
| West South Central | 10,019 | 41 | 1,996 |
| Mountain | 564 | 445 | 283 |
| Pacific | 6,044 | 4,508 | 587 |
| **U.S. Total** | **30,925** | **8,754** | **8,492** |
| | **1992 (1 Megawatt or More)** | | |
| New England | 2,115 | 1,429 | 861 |
| Middle Atlantic | 5,883 | 1,081 | 415 |
| East North Central | 4,024 | 387 | 1,038 |
| West North Central | 956 | 141 | 127 |
| South Atlantic | 5,413 | 1,388 | 2,642 |
| East South Central | 486 | 188 | 862 |
| West South Central | 10,239 | 266 | 2,176 |
| Mountain | 966 | 601 | 285 |
| Pacific | 6,941 | 5,239 | 668 |
| **U.S. Total** | **37,022** | **10,719** | **9,074** |
| | **1993 (1 Megawatt or More)** | | |
| New England | 2,369 | 1,479 | 882 |
| Middle Atlantic | 7,107 | 1,089 | 535 |
| East North Central | 4,079 | 421 | 1,046 |
| West North Central | 972 | 143 | 146 |
| South Atlantic | 6,357 | 1,358 | 2,587 |
| East South Central | 444 | 253 | 1,037 |
| West South Central | 10,673 | 255 | 2,142 |
| Mountain | 1,042 | 635 | 344 |
| Pacific | 7,420 | 5,205 | 760 |
| **U.S. Total** | **40,463** | **10,836** | **9,478** |
| | **1994 (1 Megawatt or More)** | | |
| New England | 2,532 | 1,486 | 877 |
| Middle Atlantic | 9,956 | 1,215 | 581 |
| East North Central | 4,476 | 341 | 1,130 |
| West North Central | 959 | 178 | 159 |
| South Atlantic | 7,778 | 1,799 | 2,806 |
| East South Central | 426 | 245 | 1,418 |
| West South Central | 11,339 | 255 | 2,170 |
| Mountain | 1,819 | 610 | 253 |
| Pacific | 7,700 | 5,092 | 861 |
| **U.S. Total** | **46,986** | **11,221** | **10,254** |
| | **1995 (1 Megawatt or More)** | | |
| New England | 2,619 | 1,426 | 992 |
| Middle Atlantic | 10,617 | 1,269 | 591 |
| East North Central | 4,243 | 503 | 1,171 |
| West North Central | 918 | 185 | 130 |
| South Atlantic | 8,202 | 2,095 | 2,698 |
| East South Central | 437 | 234 | 1,418 |
| West South Central | 11,413 | 261 | 2,217 |
| Mountain | 1,890 | 614 | 253 |
| Pacific | 8,014 | 5,014 | 831 |
| **U.S. Total** | **48,354** | **11,601** | **10,299** |

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

2 Includes hydroelectric, geothermal, solar, wind, wood, wood waste, peat, wood liquors, railroad ties, pitch, municipal solid waste, other waste, agricultural waste, straw, tires, landfill gases, fish oils, tall oil, digester gas, sludge, other (sulfur, hydrogen, batteries, chemicals, spent sulfite liquors), and/or nuclear as energy sources.

Notes: •For a summary of 1991 through 1995 data for 5 megawatts or more, see Table 52. •See Technical Notes for a description of allocating capacity. •Data for above years are final. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 54. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1991 Through 1995 (Megawatts)

| Census Division | Coal[1] | Natural Gas[2] | Petroleum[3] only / and Natural Gas[4] | Hydroelectric/ Geothermal/ Solar / Wind | Wood[5] / Waste[6] | Other[7] / Nuclear | Total |
|---|---|---|---|---|---|---|---|
| **1991 (5 Megawatts or More)** | | | | | | | |
| New England | 353 | 793 | 1,086 | 432 | 1,192 | — | 3,856 |
| Middle Atlantic | 1,328 | 1,053 | 1,636 | 239 | 684 | — | 4,940 |
| East North Central | 1,035 | 2,840 | 523 | 59 | 577 | — | 5,033 |
| West North Central | W | W | 84 | 55 | 104 | — | 1,103 |
| South Atlantic | 2,114 | 632 | 1,165 | 155 | 2,809 | 388 | 7,263 |
| East South Central | 276 | 239 | W | — | 874 | W | 1,489 |
| West South Central | W | 9,244 | 806 | — | 1,157 | W | 12,056 |
| Mountain | 162 | 489 | W | 363 | 159 | W | 1,292 |
| Pacific | W | W | 824 | 3,343 | 1,652 | 13 | 11,138 |
| **U.S. Total** | **7,291** | **20,259** | **6,256** | **4,647** | **9,207** | **510** | **48,171** |
| **1992 (1 Megawatt or More)** | | | | | | | |
| New England | 261 | 413 | 1,702 | 579 | 1,448 | — | 4,404 |
| Middle Atlantic | 1,582 | 1,570 | 2,971 | W | 787 | W | 7,379 |
| East North Central | 1,240 | 2,845 | 619 | W | 626 | W | 5,449 |
| West North Central | 737 | 146 | 146 | 73 | 122 | — | 1,224 |
| South Atlantic | 2,649 | 825 | 2,474 | 205 | 2,870 | 420 | 9,443 |
| East South Central | 288 | 255 | W | — | 889 | W | 1,535 |
| West South Central | 828 | 9,521 | 1,020 | W | 1,095 | W | 12,680 |
| Mountain | 175 | 790 | W | 514 | 166 | W | 1,852 |
| Pacific | 743 | 5,176 | W | 4,037 | 1,808 | W | 12,848 |
| **U.S. Total** | **8,503** | **21,542** | **10,207** | **6,120** | **9,812** | **630** | **56,814** |
| **1993 (1 Megawatt or More)** | | | | | | | |
| New England | 363 | 587 | 1,780 | 587 | 1,412 | — | 4,729 |
| Middle Atlantic | 2,049 | 1,860 | 3,494 | W | 856 | W | 8,730 |
| East North Central | 1,733 | 2,523 | 525 | W | 646 | W | 5,546 |
| West North Central | 758 | 118 | 157 | 73 | 156 | — | 1,261 |
| South Atlantic | 2,770 | 1,664 | 2,332 | 209 | 2,953 | 375 | 10,303 |
| East South Central | 289 | 222 | W | — | 1,099 | W | 1,734 |
| West South Central | 828 | 9,915 | 1,022 | W | 1,089 | W | 13,069 |
| Mountain | 233 | 808 | W | 548 | 166 | W | 2,020 |
| Pacific | 749 | 5,768 | W | 4,099 | 1,801 | W | 13,385 |
| **U.S. Total** | **9,772** | **23,463** | **10,548** | **6,232** | **10,177** | **585** | **60,778** |
| **1994 (1 Megawatt or More)** | | | | | | | |
| New England | 353 | 1,028 | 1,512 | 586 | 1,416 | — | 4,895 |
| Middle Atlantic | 2,302 | 4,533 | W | 441 | 888 | W | 11,752 |
| East North Central | 2,057 | 2,544 | 572 | 115 | 658 | — | 5,947 |
| West North Central | 729 | 122 | 182 | 95 | 168 | — | 1,296 |
| South Atlantic | 2,771 | 2,033 | 3,436 | 568 | 3,197 | 379 | 12,384 |
| East South Central | 323 | 224 | W | W | 1,265 | W | 2,088 |
| West South Central | 828 | 10,652 | 943 | W | 1,125 | W | 13,764 |
| Mountain | 238 | 1,289 | W | 551 | 157 | W | 2,682 |
| Pacific | 771 | 5,630 | W | 4,069 | 1,692 | W | 13,654 |
| **U.S. Total** | **10,372** | **28,055** | **12,081** | **6,790** | **10,566** | **597** | **68,461** |
| **1995 (1 Megawatt or More)** | | | | | | | |
| New England | 353 | 1,118 | 1,579 | 584 | 1,404 | — | 5,037 |
| Middle Atlantic | 2,530 | 4,713 | W | 485 | 973 | W | 12,477 |
| East North Central | W | 3,044 | 577 | 103 | 690 | W | 5,917 |
| West North Central | 782 | 53 | 127 | 95 | 176 | — | 1,232 |
| South Atlantic | 3,536 | 1,746 | 3,755 | 568 | 3,010 | 379 | 12,995 |
| East South Central | 312 | 225 | W | W | 1,254 | W | 2,088 |
| West South Central | W | 10,929 | 1,129 | W | 1,145 | W | 13,891 |
| Mountain | W | 1,294 | 447 | 560 | 153 | W | 2,757 |
| Pacific | W | 6,151 | 1,387 | 4,012 | 1,542 | W | 13,860 |
| **U.S. Total** | **10,454** | **29,272** | **12,837** | **6,771** | **10,347** | **574** | **70,254** |

1 Includes coal, anthracite culm, coke breeze, fine coal and coal waste.
2 Includes natural gas, butane, ethane, propane, waste heat and waste gases.
3 Includes petroleum, petroleum coke, diesel, kerosene, and petroleum sludge and tar.
4 Includes petroleum used as a single energy source, and petroleum and natural gas used as a fuel combination by themselves and with other fuels.
5 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge.
6 Includes municipal solid waste, agricultural waste, straw, tires, landfill gases, tall oil, digester gas and other waste.
7 Includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics.

Notes: •For a summary of 1991 through 1995 data for 5 megawatts or more, see Table 52. •Data for above years are final. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 55. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and State, 1995 (Megawatts)

| State | Coal[1] | Natural Gas[2] | Petroleum[3] only / and Natural Gas[4] | Hydroelectric/ Geothermal/ Solar / Wind | Wood[5] / Waste[6] | Other[7] / Nuclear | Total |
|---|---|---|---|---|---|---|---|
| | 1995 (1 Megawatt or More) | | | | | | |
| Alaska | W | W | 58 | — | W | — | 310 |
| Alabama | W | 140 | W | — | 796 | — | 1,045 |
| Arkansas | — | 85 | W | W | 368 | — | 459 |
| Arizona | W | W | 55 | — | — | — | 175 |
| California | 449 | 5,505 | 549 | 3,713 | 1,001 | — | 11,218 |
| Colorado | W | 658 | W | 32 | — | — | 727 |
| Connecticut | W | W | 172 | 22 | 260 | — | 721 |
| District of Columbia | W | W | — | — | — | — | 3 |
| Delaware | W | W | W | — | — | W | 186 |
| Florida | W | 1,437 | 496 | — | 1,243 | W | 4,251 |
| Georgia | 228 | 78 | 675 | 14 | 511 | — | 1,507 |
| Hawaii | W | W | W | 82 | 197 | — | 836 |
| Iowa | 277 | W | W | W | W | — | 347 |
| Idaho | W | — | — | 265 | W | W | 439 |
| Illinois | 393 | 285 | 53 | W | W | — | 782 |
| Indiana | 257 | W | 293 | — | W | — | 850 |
| Kansas | — | 44 | W | W | — | — | 55 |
| Kentucky | W | — | — | — | W | — | 4 |
| Louisiana | — | 2,130 | 274 | W | 499 | W | 3,117 |
| Massachusetts | W | 773 | 735 | W | 328 | — | 1,933 |
| Maryland | W | — | W | — | 139 | — | 385 |
| Maine | W | W | 296 | 359 | 631 | — | 1,428 |
| Michigan | 280 | 2,437 | 98 | W | 464 | W | 3,310 |
| Minnesota | 371 | W | W | 87 | 159 | — | 665 |
| Missouri | 104 | W | W | — | — | — | 117 |
| Mississippi | — | W | W | — | 345 | — | 391 |
| Montana | W | — | W | W | W | — | 129 |
| North Carolina | 1,018 | W | 202 | W | 221 | W | 1,919 |
| North Dakota | W | — | W | — | W | — | 37 |
| Nebraska | W | W | — | — | — | — | 10 |
| New Hampshire | — | — | 22 | 91 | 146 | — | 259 |
| New Jersey | W | 1,359 | 1,416 | W | 191 | — | 3,494 |
| New Mexico | — | 102 | W | — | W | — | 195 |
| Nevada | — | 357 | W | 241 | — | W | 845 |
| New York | 398 | 2,827 | 2,010 | W | 415 | W | 6,060 |
| Ohio | 205 | W | 84 | W | 30 | — | 350 |
| Oklahoma | W | 306 | — | — | W | — | 850 |
| Oregon | W | W | W | 115 | 187 | — | 396 |
| Pennsylvania | 1,617 | 527 | 323 | 89 | 367 | — | 2,923 |
| Rhode Island | — | 250 | 354 | W | W | — | 621 |
| South Carolina | W | W | W | 19 | 296 | — | 430 |
| South Dakota | — | — | — | — | — | — | — |
| Tennessee | 287 | W | — | W | 109 | W | 648 |
| Texas | W | 8,407 | 852 | — | 198 | W | 9,465 |
| Utah | W | W | W | W | — | — | 142 |
| Virginia | 989 | 138 | 1,971 | 22 | 600 | — | 3,719 |
| Vermont | — | — | — | W | W | — | 75 |
| Washington | W | 346 | 516 | 101 | 119 | W | 1,100 |
| Wisconsin | 346 | W | 49 | 52 | 150 | W | 625 |
| West Virginia | 344 | W | W | W | — | — | 595 |
| Wyoming | W | W | W | W | — | W | 104 |
| **U.S. Total** | 10,454 | 29,272 | 12,837 | 6,771 | 10,347 | 574 | 70,254 |

1 Includes coal, anthracite culm, coke breeze, fine coal and coal waste.
2 Includes natural gas, butane, ethane, propane, waste heat and waste gases.
3 Includes petroleum, petroleum coke, diesel, kerosene, and petroleum sludge and tar.
4 Includes petroleum used as a single energy source, and petroleum and natural gas used as a fuel combination by themselves and with other fuels.
5 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge.
6 Includes municipal solid waste, agricultural waste, straw, tires, landfill gases, tall oil, digester gas and other waste.
7 Includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics.

Notes: •For a summary of 1991 through 1995 data for 5 megawatts or more, see Table 52. •Data for above year are final. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 56. Installed Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1991 Through 1995

(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) |
| **1991 (5 Megawatts or More)** | | | | | | |
| New England | 69 | 2,719 | 22 | 1,137 | 91 | 3,856 |
| Middle Atlantic | 105 | 4,474 | 17 | 467 | 122 | 4,940 |
| East North Central | 38 | 3,080 | 52 | 1,954 | 90 | 5,033 |
| West North Central | 14 | 478 | 22 | 625 | 36 | 1,103 |
| South Atlantic | 86 | 5,149 | 47 | 2,113 | 133 | 7,263 |
| East South Central | 16 | 753 | 17 | 736 | 33 | 1,489 |
| West South Central | 87 | 10,016 | 30 | 2,040 | 117 | 12,056 |
| Mountain | 28 | 843 | 15 | 449 | 43 | 1,292 |
| Pacific | 276 | 9,458 | 86 | 1,681 | 362 | 11,138 |
| **U.S. Total** | **719** | **36,969** | **308** | **11,202** | **1,027** | **48,171** |
| **1992 (1 Megawatt or More)** | | | | | | |
| New England | 111 | 3,077 | 75 | 1,327 | 186 | 4,404 |
| Middle Atlantic | 211 | 6,924 | 48 | 455 | 259 | 7,379 |
| East North Central | 95 | 3,341 | 99 | 2,108 | 194 | 5,449 |
| West North Central | 23 | 505 | 44 | 720 | 67 | 1,224 |
| South Atlantic | 127 | 6,256 | 95 | 3,187 | 222 | 9,443 |
| East South Central | 23 | 822 | 23 | 713 | 46 | 1,535 |
| West South Central | 107 | 10,551 | 59 | 2,128 | 166 | 12,680 |
| Mountain | 73 | 1,313 | 37 | 540 | 110 | 1,852 |
| Pacific | 409 | 10,972 | 149 | 1,876 | 558 | 12,848 |
| **U.S. Total** | **1,179** | **43,760** | **629** | **13,054** | **1,808** | **56,814** |
| **1993 (1 Megawatt or More)** | | | | | | |
| New England | 116 | 3,404 | 73 | 1,325 | 189 | 4,729 |
| Middle Atlantic | 230 | 8,351 | 44 | 379 | 274 | 8,730 |
| East North Central | 98 | 3,403 | 101 | 2,143 | 199 | 5,546 |
| West North Central | 25 | 512 | 49 | 749 | 74 | 1,261 |
| South Atlantic | 139 | 7,011 | 97 | 3,291 | 236 | 10,303 |
| East South Central | 24 | 881 | 30 | 853 | 54 | 1,734 |
| West South Central | 107 | 11,159 | 60 | 1,910 | 167 | 13,069 |
| Mountain | 81 | 1,446 | 38 | 574 | 119 | 2,020 |
| Pacific | 412 | 11,606 | 142 | 1,779 | 554 | 13,385 |
| **U.S. Total** | **1,232** | **47,774** | **634** | **13,004** | **1,866** | **60,778** |
| **1994 (1 Megawatt or More)** | | | | | | |
| New England | 117 | 3,420 | 75 | 1,475 | 192 | 4,895 |
| Middle Atlantic | 248 | 11,350 | 48 | 402 | 296 | 11,752 |
| East North Central | 101 | 3,448 | 118 | 2,498 | 219 | 5,947 |
| West North Central | 26 | 535 | 51 | 760 | 77 | 1,296 |
| South Atlantic | 151 | 8,300 | 129 | 4,083 | 280 | 12,384 |
| East South Central | 24 | 930 | 35 | 1,159 | 59 | 2,088 |
| West South Central | 107 | 11,846 | 61 | 1,917 | 168 | 13,764 |
| Mountain | 85 | 1,905 | 38 | 776 | 123 | 2,682 |
| Pacific | 408 | 11,826 | 146 | 1,828 | 554 | 13,654 |
| **U.S. Total** | **1,267** | **53,562** | **701** | **14,900** | **1,968** | **68,461** |
| **1995 (1 Megawatt or More)** | | | | | | |
| New England | 119 | 3,478 | 73 | 1,560 | 192 | 5,037 |
| Middle Atlantic | 258 | 12,087 | 48 | 390 | 306 | 12,477 |
| East North Central | 112 | 3,712 | 110 | 2,205 | 222 | 5,917 |
| West North Central | 28 | 575 | 52 | 658 | 80 | 1,232 |
| South Atlantic | 160 | 9,066 | 125 | 3,929 | 285 | 12,995 |
| East South Central | 28 | 1,143 | 31 | 945 | 59 | 2,088 |
| West South Central | 109 | 12,165 | 58 | 1,726 | 167 | 13,891 |
| Mountain | 85 | 1,980 | 38 | 777 | 123 | 2,757 |
| Pacific | 400 | 11,940 | 139 | 1,920 | 539 | 13,860 |
| **U.S. Total** | **1,299** | **56,145** | **674** | **14,109** | **1,973** | **70,254** |

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978.

Notes: •Data for above years are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 57. Installed Capacity at U.S. Nonutilities Attributed to Major Industry Groups and Census Divisions, 1991 Through 1995

(Megawatts)

| Census Division | Manufacturing | Transportation and Public Utilities | Services | Mining | Public Administration | Other Industry Groups | Total |
|---|---|---|---|---|---|---|---|
| **1991 (5 Megawatts or More)** | | | | | | | |
| New England | 1,925 | 1,898 | 33 | — | — | — | 3,856 |
| Middle Atlantic | 3,326 | 984 | 184 | W | W | 162 | 4,940 |
| East North Central | 4,627 | 109 | 193 | W | — | W | 5,033 |
| West North Central | 607 | W | 130 | W | — | — | 1,103 |
| South Atlantic | 5,474 | 1,587 | 124 | — | W | W | 7,263 |
| East South Central | 1,466 | W | — | — | W | — | 1,489 |
| West South Central | 11,291 | 464 | W | W | — | — | 12,056 |
| Mountain | 493 | 316 | W | W | — | 268 | 1,292 |
| Pacific | 3,558 | W | W | W | W | W | 11,138 |
| **U.S. Total** | **32,767** | **10,946** | **1,111** | **2,199** | **455** | **693** | **48,171** |
| **1992 (1 Megawatt or More)** | | | | | | | |
| New England | 2,120 | 2,167 | W | — | W | — | 4,404 |
| Middle Atlantic | 5,112 | 1,395 | 410 | W | W | 162 | 7,379 |
| East North Central | 4,864 | 253 | 239 | W | W | W | 5,449 |
| West North Central | 695 | W | 138 | W | W | W | 1,224 |
| South Atlantic | 6,371 | 2,824 | 150 | W | W | 61 | 9,443 |
| East South Central | 1,497 | W | W | W | W | — | 1,535 |
| West South Central | 11,865 | 442 | 193 | 180 | — | — | 12,680 |
| Mountain | 746 | 474 | 157 | 197 | — | 278 | 1,852 |
| Pacific | 4,342 | 6,200 | 239 | 1,560 | 326 | 182 | 12,848 |
| **U.S. Total** | **37,612** | **13,951** | **1,643** | **2,413** | **483** | **713** | **56,814** |
| **1993 (1 Megawatt or More)** | | | | | | | |
| New England | 2,248 | 2,363 | W | — | W | — | 4,729 |
| Middle Atlantic | 5,807 | 1,989 | 511 | W | W | 225 | 8,730 |
| East North Central | 4,851 | 301 | 271 | W | W | W | 5,546 |
| West North Central | 702 | 184 | 165 | W | W | W | 1,261 |
| South Atlantic | 6,925 | 2,914 | 158 | W | W | 269 | 10,303 |
| East South Central | 1,676 | 18 | W | W | W | — | 1,734 |
| West South Central | 12,245 | 442 | 203 | 180 | — | — | 13,069 |
| Mountain | 772 | 566 | 158 | 245 | — | 278 | 2,020 |
| Pacific | 4,678 | 5,532 | 324 | 2,439 | 239 | 173 | 13,385 |
| **U.S. Total** | **39,904** | **14,309** | **1,908** | **3,246** | **406** | **1,005** | **60,778** |
| **1994 (1 Megawatt or More)** | | | | | | | |
| New England | 2,267 | 2,499 | W | — | — | W | 4,895 |
| Middle Atlantic | 8,509 | 2,168 | 546 | W | W | 225 | 11,752 |
| East North Central | 5,129 | 373 | 287 | W | W | 90 | 5,947 |
| West North Central | 706 | 213 | 166 | W | W | W | 1,296 |
| South Atlantic | 8,180 | 3,887 | 176 | W | W | 67 | 12,384 |
| East South Central | 2,029 | 18 | W | 27 | W | — | 2,088 |
| West South Central | 12,940 | 442 | 202 | 180 | — | — | 13,764 |
| Mountain | 833 | 779 | 139 | 245 | — | 686 | 2,682 |
| Pacific | 5,086 | 5,307 | 433 | 2,438 | 239 | 151 | 13,654 |
| **U.S. Total** | **45,678** | **15,686** | **2,070** | **3,252** | **542** | **1,234** | **68,461** |
| **1995 (1 Megawatt or More)** | | | | | | | |
| New England | 2,281 | 2,602 | W | — | — | W | 5,037 |
| Middle Atlantic | 9,202 | 2,074 | 553 | W | W | 225 | 12,477 |
| East North Central | 5,086 | 356 | 353 | W | W | W | 5,917 |
| West North Central | 755 | 104 | 164 | W | W | W | 1,232 |
| South Atlantic | 8,842 | 3,704 | 169 | W | W | 204 | 12,995 |
| East South Central | 2,027 | W | W | 27 | W | — | 2,088 |
| West South Central | 13,297 | W | 202 | 177 | — | W | 13,891 |
| Mountain | 865 | 823 | 132 | 245 | — | 692 | 2,757 |
| Pacific | 5,250 | 5,258 | 436 | 2,498 | 242 | 176 | 13,860 |
| **U.S. Total** | **47,606** | **15,144** | **2,165** | **3,428** | **544** | **1,368** | **70,254** |

Notes: •Data shown in this table are nonutility generating capacity attributed to major industry groups and census divisions of the users of the electrical energy. •Data for above years are final. •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 58. Gross Generation for U.S. Nonutility Power Producers by Energy Source and Census Division, 1991 Through 1995

(Million Kilowatthours)

| Census Division | Coal[1] | Petroleum[2] | Natural Gas[3] | Hydroelectric | Geothermal/ Solar/Wind | Wood[4] / Waste[5] | Other[6] / Nuclear | Total |
|---|---|---|---|---|---|---|---|---|
| **1991 (5 Megawatts or More)** | | | | | | | | |
| New England | 2,527 | 1,292 | 6,710 | 2,264 | — | 7,553 | — | 20,347 |
| Middle Atlantic | 7,741 | W | 11,050 | 877 | — | 3,933 | W | 24,886 |
| East North Central | 5,456 | W | 12,173 | 266 | W | 3,084 | — | 21,424 |
| West North Central | 1,841 | 36 | 745 | 227 | — | 466 | — | 3,316 |
| South Atlantic | 11,504 | 1,563 | 3,706 | 760 | — | 12,991 | 2,249 | 32,773 |
| East South Central | 2,005 | W | 2,132 | — | — | 4,735 | W | 9,013 |
| West South Central | 5,459 | W | 60,095 | — | — | 5,404 | W | 73,404 |
| Mountain | 1,044 | 15 | 1,932 | 511 | 991 | 755 | 193 | 5,442 |
| Pacific | 3,009 | W | 32,796 | 1,337 | W | 8,820 | W | 57,843 |
| **U.S. Total** | **40,587** | **7,814** | **131,340** | **6,243** | **11,035** | **47,741** | **3,688** | **248,448** |
| **1992 (1 Megawatt or More)** | | | | | | | | |
| New England | 2,397 | 1,506 | 11,056 | 2,694 | — | 8,418 | — | 26,071 |
| Middle Atlantic | 9,747 | W | 22,504 | 1,916 | — | 5,244 | W | 40,890 |
| East North Central | 6,569 | 510 | 13,549 | W | — | 3,166 | W | 24,358 |
| West North Central | 2,565 | 50 | 749 | 336 | — | 670 | — | 4,371 |
| South Atlantic | 13,122 | 2,354 | 5,266 | 1,095 | — | 14,936 | 2,030 | 38,804 |
| East South Central | 2,152 | W | 2,401 | — | — | 5,163 | W | 9,962 |
| West South Central | 5,354 | 2,129 | 62,469 | W | — | 5,586 | W | 77,050 |
| Mountain | 1,131 | 40 | 3,450 | 600 | 1,214 | 816 | 204 | 7,455 |
| Pacific | 4,327 | 3,017 | 37,354 | W | 11,026 | 9,607 | W | 67,040 |
| **U.S. Total** | **47,363** | **10,963** | **158,798** | **9,446** | **12,241** | **53,607** | **3,583** | **296,001** |
| **1993 (1 Megawatt or More)** | | | | | | | | |
| New England | 2,417 | 1,764 | 12,460 | 2,526 | — | 9,062 | — | 28,229 |
| Middle Atlantic | 10,950 | W | 28,381 | 1,724 | — | 5,714 | W | 48,705 |
| East North Central | 7,138 | 627 | 14,274 | W | — | 3,602 | W | 26,211 |
| West North Central | 2,852 | 63 | 687 | 336 | — | 737 | — | 4,675 |
| South Atlantic | 15,466 | 2,774 | 7,886 | 963 | — | 14,821 | 1,710 | 43,620 |
| East South Central | 2,289 | W | 2,170 | — | — | 6,019 | W | 10,741 |
| West South Central | 5,798 | 3,239 | 63,077 | W | — | 5,804 | W | 80,073 |
| Mountain | 1,317 | 112 | 4,638 | 948 | 1,588 | 767 | 201 | 9,572 |
| Pacific | 5,140 | 2,905 | 40,708 | W | 12,110 | 9,220 | W | 73,400 |
| **U.S. Total** | **53,367** | **13,364** | **174,282** | **11,511** | **13,698** | **55,746** | **3,259** | **325,226** |
| **1994 (1 Megawatt or More)** | | | | | | | | |
| New England | 2,575 | 1,937 | 13,917 | 2,709 | — | 8,787 | — | 29,925 |
| Middle Atlantic | 12,169 | 2,213 | 34,178 | 1,877 | — | 5,824 | 197 | 56,457 |
| East North Central | 8,652 | 717 | 15,139 | 533 | — | 3,952 | — | 28,993 |
| West North Central | 3,111 | W | 726 | 339 | W | 789 | — | 5,077 |
| South Atlantic | 17,122 | 3,369 | 11,348 | 2,983 | — | 15,328 | 2,002 | 52,152 |
| East South Central | 2,325 | 174 | 2,246 | W | — | 6,874 | W | 12,786 |
| West South Central | 6,227 | W | 64,768 | W | — | 5,882 | W | 81,989 |
| Mountain | 1,567 | 115 | 6,131 | 837 | W | 768 | W | 11,273 |
| Pacific | 5,285 | 3,114 | 43,762 | 1,918 | 12,752 | 9,188 | 252 | 76,271 |
| **U.S. Total** | **59,035** | **15,069** | **192,214** | **13,227** | **14,428** | **57,392** | **3,560** | **354,925** |
| **1995 (1 Megawatt or More)** | | | | | | | | |
| New England | 2,404 | 2,112 | 13,418 | 2,561 | — | 8,855 | — | 29,350 |
| Middle Atlantic | 14,803 | 1,781 | 45,181 | 1,584 | — | 6,230 | 189 | 69,768 |
| East North Central | 6,813 | 695 | 16,061 | W | — | 4,305 | W | 28,436 |
| West North Central | 2,680 | W | 690 | 303 | W | 908 | — | 4,702 |
| South Atlantic | 18,891 | 2,729 | 15,735 | 2,799 | — | 15,486 | 1,985 | 57,624 |
| East South Central | 2,375 | 125 | 2,181 | W | — | 7,030 | W | 12,708 |
| West South Central | 3,786 | W | 66,547 | W | — | 5,894 | 1,110 | 83,172 |
| Mountain | 1,511 | 179 | 6,828 | 1,171 | W | 745 | W | 12,263 |
| Pacific | 4,404 | W | 43,692 | 4,070 | 12,205 | 7,523 | W | 76,415 |
| **U.S. Total** | **57,668** | **16,987** | **210,332** | **14,774** | **13,921** | **56,975** | **3,780** | **374,438** |

1 Includes coal, anthracite culm, coke breeze, fine coal and coal waste.
2 Includes petroleum, petroleum coke, diesel, kerosene, and petroleum sludge and tar.
3 Includes natural gas, butane, ethane, propane, waste heat and waste gases.
4 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge.
5 Includes municipal solid waste, agricultural waste, straw, tires, landfill gases, tall oil, digester gas and other waste.
6 Includes hydrogen, sulfur, batteries, fish oil, chemicals, and spent sulfite liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics.

Notes: •For a summary of 1991 through 1995 data for 5 megawatts or more, see Table 52. •Data for above years are final. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 59. Gross Generation for U.S. Nonutility Power Producers by Energy Source and State, 1995

(Million Kilowatthours)

| State | Coal[1] | Petroleum[2] | Natural Gas[3] | Hydroelectric | Geothermal/ Solar/Wind | Wood[4] / Waste[5] | Other[6] / Nuclear | Total |
|---|---|---|---|---|---|---|---|---|
| | 1995 (1 Megawatt or More) | | | | | | | |
| Alaska | W | 139 | W | — | — | W | — | 1,232 |
| Alabama | 565 | 106 | 1,280 | — | — | 4,318 | — | 6,269 |
| Arkansas | W | W | 912 | — | — | 1,634 | W | 2,618 |
| Arizona | W | 20 | 477 | — | — | W | — | 878 |
| California | 2,979 | 1,904 | 37,583 | W | 11,942 | 5,253 | W | 62,832 |
| Colorado | W | W | 2,666 | 125 | — | W | — | 3,057 |
| Connecticut | W | 183 | 1,257 | W | — | 1,608 | — | 4,812 |
| District of Columbia | — | — | — | — | — | — | — | — |
| Delaware | W | W | W | — | — | — | W | 750 |
| Florida | 4,153 | 640 | 8,864 | — | — | 5,839 | 1,702 | 21,197 |
| Georgia | 1,129 | 668 | 1,304 | 51 | — | 3,133 | — | 6,285 |
| Hawaii | W | 1,755 | W | 83 | W | 693 | W | 4,327 |
| Iowa | 1,002 | 9 | 105 | W | — | W | — | 1,177 |
| Idaho | W | W | W | 936 | — | 571 | W | 1,823 |
| Illinois | 1,901 | W | 1,604 | W | — | W | — | 3,952 |
| Indiana | 950 | W | 3,100 | — | — | W | — | 4,281 |
| Kansas | — | W | 181 | W | — | — | — | 195 |
| Kentucky | — | W | — | — | — | W | — | 4 |
| Louisiana | W | W | 14,034 | W | — | 2,915 | W | 20,196 |
| Massachusetts | W | 220 | 8,310 | W | — | 2,156 | — | 11,022 |
| Maryland | W | W | W | — | — | 708 | — | 1,773 |
| Maine | W | 1,558 | W | 1,727 | — | 3,741 | — | 7,625 |
| Michigan | W | 176 | 10,667 | 130 | — | 2,694 | W | 15,587 |
| Minnesota | 1,287 | W | 316 | 280 | W | 835 | — | 2,803 |
| Missouri | W | W | W | — | — | W | — | 333 |
| Mississippi | W | W | 691 | — | — | 2,048 | — | 2,820 |
| Montana | W | W | W | W | — | W | — | 617 |
| North Carolina | 6,139 | 256 | 542 | W | — | 1,787 | W | 10,788 |
| North Dakota | W | W | W | — | — | W | — | 186 |
| Nebraska | W | — | W | — | — | — | — | 8 |
| New Hampshire | — | 111 | — | 406 | — | 1,062 | — | 1,580 |
| New Jersey | W | 723 | 14,549 | W | — | 1,320 | — | 18,815 |
| New Mexico | — | W | 399 | — | — | W | — | 413 |
| Nevada | — | W | 2,428 | W | 1,659 | — | W | 4,127 |
| New York | 2,547 | W | 26,751 | 1,223 | — | 2,397 | W | 33,502 |
| Ohio | 747 | 31 | 365 | W | — | W | — | 1,551 |
| Oklahoma | W | W | 1,511 | — | — | W | — | 5,031 |
| Oregon | W | W | 285 | 356 | — | 653 | — | 1,321 |
| Pennsylvania | 10,043 | 559 | 3,881 | W | — | 2,513 | W | 17,450 |
| Rhode Island | — | 38 | 3,836 | W | — | W | — | 3,965 |
| South Carolina | 561 | 165 | 102 | 65 | — | 1,738 | — | 2,632 |
| South Dakota | — | — | — | — | — | — | — | — |
| Tennessee | 1,742 | W | 210 | W | — | 660 | W | 3,615 |
| Texas | W | 3,080 | 50,090 | — | — | W | 615 | 55,326 |
| Utah | W | W | W | W | — | — | — | 744 |
| Virginia | 4,328 | 566 | 3,587 | W | — | 2,279 | W | 10,844 |
| Vermont | — | W | — | 140 | — | W | — | 347 |
| Washington | W | W | 4,706 | 477 | — | 790 | W | 6,703 |
| Wisconsin | 1,311 | W | 325 | 276 | — | 840 | W | 3,066 |
| West Virginia | 2,128 | W | 403 | W | — | W | W | 3,356 |
| Wyoming | W | W | W | — | — | — | W | 604 |
| **U.S. Total** | 57,668 | 16,987 | 210,332 | 14,774 | 13,921 | 56,975 | 3,780 | 374,438 |

1 Includes coal, anthracite culm, coke breeze, fine coal and coal waste.
2 Includes petroleum, petroleum coke, diesel, kerosene, and petroleum sludge and tar.
3 Includes natural gas, butane, ethane, propane, waste heat and waste gases.
4 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge.
5 Includes municipal solid waste, agricultural waste, straw, tires, landfill gases, tall oil, digester gas and other waste.
6 Includes hydrogen, sulfur, batteries, fish oil, chemicals, and spent sulfite liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics.

Notes: •For a summary of 1991 through 1995 data for 5 megawatts or more, see Table 52. •Data for above year are final. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 60. Gross Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1991 Through 1995

(Million Kilowatthours)

| Census Division | QF Generation | | Non-QF Generation | | Total Generation | |
|---|---|---|---|---|---|---|
| | No. of Facilities | Generation (million kilowatthours) | No. of Facilities | Generation (million kilowatthours) | No. of Facilities | Generation (million kilowatthours) |
| **1991 (5 Megawatts or More)** | | | | | | |
| New England | 69 | 15,448 | 22 | 4,899 | 91 | 20,347 |
| Middle Atlantic | 105 | 23,202 | 17 | 1,684 | 122 | 24,886 |
| East North Central | 38 | 13,169 | 52 | 8,255 | 90 | 21,424 |
| West North Central | 14 | 1,984 | 22 | 1,331 | 36 | 3,316 |
| South Atlantic | 86 | 23,982 | 47 | 8,791 | 133 | 32,773 |
| East South Central | 16 | 4,909 | 17 | 4,104 | 33 | 9,013 |
| West South Central | 87 | 61,661 | 30 | 11,743 | 117 | 73,404 |
| Mountain | 28 | 3,673 | 15 | 1,769 | 43 | 5,442 |
| Pacific | 276 | 51,570 | 86 | 6,273 | 362 | 57,843 |
| **U.S. Total** | **719** | **199,599** | **308** | **48,849** | **1,027** | **248,448** |
| **1992 (1 Megawatt or More)** | | | | | | |
| New England | 111 | 18,717 | 75 | 7,354 | 186 | 26,071 |
| Middle Atlantic | 211 | 38,758 | 48 | 2,132 | 259 | 40,890 |
| East North Central | 95 | 15,683 | 99 | 8,675 | 194 | 24,358 |
| West North Central | 23 | 2,073 | 44 | 2,298 | 67 | 4,371 |
| South Atlantic | 127 | 28,916 | 95 | 9,888 | 222 | 38,804 |
| East South Central | 23 | 5,413 | 23 | 4,549 | 46 | 9,962 |
| West South Central | 107 | 65,080 | 59 | 11,970 | 166 | 77,050 |
| Mountain | 73 | 5,507 | 37 | 1,948 | 110 | 7,455 |
| Pacific | 409 | 60,979 | 149 | 6,061 | 558 | 67,040 |
| **U.S. Total** | **1,179** | **241,126** | **629** | **54,875** | **1,808** | **296,001** |
| **1993 (1 Megawatt or More)** | | | | | | |
| New England | 116 | 20,936 | 73 | 7,293 | 189 | 28,229 |
| Middle Atlantic | 230 | 46,602 | 44 | 2,102 | 274 | 48,705 |
| East North Central | 98 | 17,238 | 101 | 8,973 | 199 | 26,211 |
| West North Central | 25 | 2,257 | 49 | 2,418 | 74 | 4,675 |
| South Atlantic | 139 | 32,132 | 97 | 11,488 | 236 | 43,620 |
| East South Central | 24 | 5,383 | 30 | 5,358 | 54 | 10,741 |
| West South Central | 107 | 68,884 | 60 | 11,190 | 167 | 80,073 |
| Mountain | 81 | 7,391 | 38 | 2,181 | 119 | 9,572 |
| Pacific | 412 | 66,820 | 142 | 6,580 | 554 | 73,400 |
| **U.S. Total** | **1,232** | **267,641** | **634** | **57,584** | **1,866** | **325,226** |
| **1994 (1 Megawatt or More)** | | | | | | |
| New England | 117 | 21,832 | 75 | 8,093 | 192 | 29,925 |
| Middle Atlantic | 248 | 54,274 | 48 | 2,183 | 296 | 56,457 |
| East North Central | 101 | 17,961 | 118 | 11,033 | 219 | 28,993 |
| West North Central | 26 | 2,480 | 51 | 2,597 | 77 | 5,077 |
| South Atlantic | 151 | 39,312 | 129 | 12,840 | 280 | 52,152 |
| East South Central | 24 | 5,702 | 35 | 7,085 | 59 | 12,786 |
| West South Central | 107 | 70,773 | 61 | 11,217 | 168 | 81,989 |
| Mountain | 85 | 9,089 | 38 | 2,183 | 123 | 11,273 |
| Pacific | 407 | 70,659 | 145 | 5,612 | 554 | 76,271 |
| **U.S. Total** | **1,267** | **292,082** | **701** | **62,843** | **1,968** | **354,925** |
| **1995 (1 Megawatt or More)** | | | | | | |
| New England | 119 | 21,681 | 73 | 7,669 | 192 | 29,350 |
| Middle Atlantic | 258 | 67,661 | 48 | 2,107 | 306 | 69,768 |
| East North Central | 112 | 19,255 | 110 | 9,182 | 222 | 28,436 |
| West North Central | 28 | 2,377 | 52 | 2,325 | 80 | 4,702 |
| South Atlantic | 160 | 44,277 | 125 | 13,348 | 285 | 57,624 |
| East South Central | 28 | 7,567 | 31 | 5,142 | 59 | 12,708 |
| West South Central | 109 | 73,116 | 58 | 10,056 | 167 | 83,172 |
| Mountain | 85 | 10,024 | 38 | 2,239 | 123 | 12,263 |
| Pacific | 400 | 69,168 | 139 | 7,247 | 539 | 76,415 |
| **U.S. Total** | **1,299** | **315,124** | **674** | **59,314** | **1,973** | **374,438** |

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978.

Notes: •Data for above years are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 61. Gross Generation of U.S. Nonutilities Attributed to Major Industry Groups and Census Divisions, 1991 Through 1995

(Million Kilowatthours)

| Census Division | Manufacturing | Transportation and Public Utilities | Services | Mining | Public Administration | Other Industry Groups | Total |
|---|---|---|---|---|---|---|---|
| **1991 (5 Megawatts or More)** | | | | | | | |
| New England | 9,513 | 10,670 | 164 | — | — | — | 20,347 |
| Middle Atlantic | 16,413 | 4,376 | 844 | W | W | 1,158 | 24,886 |
| East North Central | 19,332 | 791 | 810 | W | — | W | 21,424 |
| West North Central | 2,587 | W | W | W | — | — | 3,316 |
| South Atlantic | 27,959 | 4,401 | 131 | — | W | W | 32,773 |
| East South Central | 8,883 | W | — | — | W | — | 9,013 |
| West South Central | 69,739 | 2,288 | W | W | — | — | 73,404 |
| Mountain | 2,260 | 1,705 | W | W | — | 515 | 5,442 |
| Pacific | 20,786 | 24,086 | W | W | 1,984 | W | 57,843 |
| **U.S. Total** | **177,472** | **48,552** | **4,597** | **12,369** | **2,958** | **2,499** | **248,448** |
| **1992 (1 Megawatt or More)** | | | | | | | |
| New England | 12,165 | 13,444 | 461 | — | — | — | 26,071 |
| Middle Atlantic | 27,882 | 7,330 | 2,329 | W | W | 1,124 | 40,890 |
| East North Central | 21,838 | 1,366 | 750 | W | W | W | 24,358 |
| West North Central | 2,758 | W | W | W | W | W | 4,371 |
| South Atlantic | 31,230 | 6,739 | 536 | W | W | W | 38,804 |
| East South Central | 9,772 | W | W | W | W | — | 9,962 |
| West South Central | 73,635 | 1,697 | 601 | 1,116 | — | — | 77,050 |
| Mountain | 3,564 | 2,156 | 837 | W | — | W | 7,455 |
| Pacific | 24,944 | 27,233 | 1,477 | 10,666 | 2,091 | 629 | 67,040 |
| **U.S. Total** | **207,789** | **60,415** | **7,389** | **14,923** | **3,163** | **2,322** | **296,001** |
| **1993 (1 Megawatt or More)** | | | | | | | |
| New England | 12,644 | 15,120 | 466 | — | — | — | 28,229 |
| Middle Atlantic | 31,368 | 11,669 | 2,809 | W | W | 1,273 | 48,705 |
| East North Central | 23,015 | 1,698 | 987 | W | W | W | 26,211 |
| West North Central | 2,983 | 341 | W | W | W | W | 4,675 |
| South Atlantic | 33,179 | 8,461 | 657 | W | W | 1,184 | 43,620 |
| East South Central | 10,531 | 72 | W | W | W | — | 10,741 |
| West South Central | 76,103 | 2,232 | 611 | 1,127 | — | — | 80,073 |
| Mountain | 4,622 | 2,899 | 975 | W | — | W | 9,572 |
| Pacific | 26,889 | 25,056 | 2,038 | 17,228 | 1,530 | 659 | 73,400 |
| **U.S. Total** | **221,334** | **67,549** | **8,970** | **20,877** | **2,671** | **3,826** | **325,226** |
| **1994 (1 Megawatt or More)** | | | | | | | |
| New England | 13,641 | 15,743 | W | — | — | W | 29,925 |
| Middle Atlantic | 37,382 | 12,009 | 3,385 | W | 1,452 | W | 56,457 |
| East North Central | 24,909 | 2,415 | 1,067 | W | W | 254 | 28,993 |
| West North Central | 3,150 | 434 | 421 | W | W | W | 5,077 |
| South Atlantic | 41,152 | 10,142 | 635 | W | W | W | 52,152 |
| East South Central | 12,478 | 81 | W | 148 | W | — | 12,786 |
| West South Central | 78,974 | 2,013 | 539 | 464 | — | — | 81,989 |
| Mountain | 5,096 | 3,173 | 954 | 563 | — | 1,486 | 11,273 |
| Pacific | 31,053 | 22,971 | 2,406 | 17,757 | 1,523 | 561 | 76,271 |
| **U.S. Total** | **247,836** | **68,982** | **9,900** | **21,024** | **3,172** | **4,011** | **354,925** |
| **1995 (1 Megawatt or More)** | | | | | | | |
| New England | 13,334 | 15,422 | W | — | — | W | 29,350 |
| Middle Atlantic | 51,375 | 10,749 | 3,668 | W | 968 | W | 69,768 |
| East North Central | 24,716 | 1,994 | 1,345 | W | W | W | 28,436 |
| West North Central | 3,025 | W | 403 | W | W | W | 4,702 |
| South Atlantic | 45,772 | 10,998 | 657 | W | W | 168 | 57,624 |
| East South Central | 12,448 | 70 | W | 125 | W | — | 12,708 |
| West South Central | 80,971 | W | 614 | 492 | — | W | 83,172 |
| Mountain | 4,976 | 3,603 | 890 | 482 | — | 2,311 | 12,263 |
| Pacific | 30,630 | 23,352 | 2,606 | 17,730 | 1,528 | 569 | 76,415 |
| **U.S. Total** | **267,248** | **67,695** | **10,775** | **21,277** | **2,617** | **4,826** | **374,438** |

Notes: •Data shown in this table are nonutility gross generation by industry groups and census divisions. •Data for above years are final. •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 62. U.S. Nonutility Electricity Supply and Disposition for Facilities by Census Division and State, 1995

(Million Kilowatthours)

| Census Division and State | Gross Generation | | Receipts[1] | | Deliveries[2] | | Facility Use | |
|---|---|---|---|---|---|---|---|---|
| | 1 megawatt or more | 5 megawatts or more | 1 megawatt or more | 5 megawatts or more | 1 megawatt or more | 5 megawatts or more | 1 megawatt or more | 5 megawatts or more |
| **New England** | **29,350** | **28,613** | **3,858** | **3,412** | **23,967** | **23,405** | **9,241** | **8,620** |
| Connecticut | 4,812 | 4,716 | 288 | 222 | 4,064 | 3,981 | 1,036 | 957 |
| Maine | 7,625 | 7,506 | 2,509 | 2,507 | 4,556 | 4,460 | 5,578 | 5,553 |
| Massachusetts | 11,022 | 10,857 | 669 | 526 | 10,073 | 9,996 | 1,618 | 1,387 |
| New Hampshire | 1,580 | W | 287 | 110 | 1,206 | 925 | 661 | W |
| Rhode Island | 3,965 | W | W | 37 | 3,777 | 3,768 | W | W |
| Vermont | 347 | W | W | 10 | 291 | 275 | W | W |
| **Middle Atlantic** | **69,768** | **68,551** | **5,408** | **4,517** | **59,316** | **58,529** | **15,860** | **14,539** |
| New Jersey | 18,815 | 18,551 | 848 | 595 | 16,804 | 16,682 | 2,859 | 2,464 |
| New York | 33,502 | 32,774 | 1,410 | 1,183 | 30,069 | 29,483 | 4,843 | 4,475 |
| Pennsylvania | 17,450 | 17,226 | 3,151 | 2,738 | 12,443 | 12,364 | 8,158 | 7,601 |
| **East North Central** | **28,436** | **27,324** | **18,931** | **16,724** | **12,147** | **11,640** | **35,220** | **32,408** |
| Illinois | 3,952 | 3,537 | 5,903 | 5,107 | 370 | 263 | 9,484 | 8,381 |
| Indiana | 4,281 | W | 5,376 | 4,832 | 83 | W | 9,573 | 8,967 |
| Michigan | 15,587 | 15,141 | 1,813 | 1,341 | 11,294 | 11,025 | 6,106 | 5,457 |
| Ohio | 1,551 | W | 2,896 | 2,800 | 56 | W | 4,390 | 4,288 |
| Wisconsin | 3,066 | 2,936 | 2,944 | 2,645 | 343 | 266 | 5,667 | 5,315 |
| **West North Central** | **4,702** | **4,413** | **5,682** | **5,301** | **769** | **610** | **9,615** | **9,105** |
| Iowa | 1,177 | W | 1,425 | 1,369 | 209 | W | 2,394 | 2,320 |
| Kansas | 195 | W | W | W | W | — | 1,188 | W |
| Minnesota | 2,803 | 2,673 | 2,845 | 2,741 | 517 | 419 | 5,131 | 4,995 |
| Missouri | 333 | 329 | W | W | W | W | 584 | 545 |
| Nebraska | W | W | W | W | — | — | W | W |
| North Dakota | W | W | W | W | W | W | W | W |
| South Dakota | — | — | — | — | — | — | — | — |
| **South Atlantic** | **57,624** | **56,927** | **15,660** | **14,005** | **32,927** | **32,539** | **40,358** | **38,392** |
| Delaware | 750 | W | W | W | W | W | W | W |
| District of Columbia | — | — | — | — | — | — | — | — |
| Florida | 21,197 | 21,066 | 1,737 | 1,431 | 13,500 | 13,493 | 9,435 | 9,003 |
| Georgia | 6,285 | 6,186 | 3,206 | W | 368 | W | 9,123 | 8,202 |
| Maryland | 1,773 | 1,738 | W | W | W | 1,158 | W | W |
| North Carolina | 10,788 | 10,713 | 2,998 | 2,726 | 7,604 | 7,578 | 6,182 | 5,861 |
| South Carolina | 2,632 | W | 664 | W | 390 | 345 | 2,906 | 2,835 |
| Virginia | 10,844 | 10,585 | 2,823 | 2,728 | 8,548 | 8,317 | 5,119 | 4,995 |
| West Virginia | 3,356 | 3,332 | 1,779 | 1,779 | 1,241 | 1,241 | 3,894 | 3,870 |
| **East South Central** | **12,708** | **12,520** | **7,817** | **7,135** | **2,127** | **1,994** | **18,398** | **17,661** |
| Alabama | 6,269 | 6,192 | W | W | W | W | 8,558 | 8,368 |
| Kentucky | W | — | — | — | W | — | W | — |
| Mississippi | 2,820 | 2,753 | W | W | 114 | W | W | 4,146 |
| Tennessee | W | 3,574 | W | 2,588 | 1,107 | 1,017 | W | 5,146 |
| **West South Central** | **83,172** | **82,804** | **19,288** | **17,952** | **28,961** | **28,930** | **73,499** | **71,826** |
| Arkansas | 2,618 | 2,594 | W | W | W | W | 3,147 | 3,102 |
| Louisiana | 20,196 | 20,103 | 7,134 | 6,379 | 3,592 | 3,592 | 23,737 | 22,890 |
| Oklahoma | 5,031 | 5,018 | W | W | W | W | 2,635 | 2,586 |
| Texas | 55,326 | 55,089 | 10,374 | 9,850 | 21,720 | 21,691 | 43,980 | 43,248 |
| **Mountain** | **12,263** | **11,682** | **4,052** | **3,690** | **9,395** | **8,996** | **6,920** | **6,375** |
| Arizona | 878 | W | W | W | W | W | 671 | W |
| Colorado | 3,057 | 2,901 | 178 | 98 | 2,681 | 2,544 | 553 | 455 |
| Idaho | 1,823 | 1,653 | W | W | 1,667 | 1,497 | W | W |
| Montana | 617 | 611 | W | W | 468 | W | W | W |
| Nevada | 4,127 | 4,075 | W | W | 3,799 | 3,754 | W | W |
| New Mexico | 413 | 338 | 1,313 | 1,302 | W | — | W | 1,640 |
| Utah | 744 | W | W | W | W | W | W | W |
| Wyoming | 604 | W | W | W | W | W | 951 | W |
| **Pacific** | **76,415** | **74,711** | **9,223** | **8,564** | **62,441** | **61,470** | **23,197** | **21,805** |
| Alaska | 1,232 | 1,154 | 106 | 106 | 31 | 27 | 1,307 | 1,233 |
| California | 62,832 | 61,529 | 4,047 | 3,553 | 52,412 | 51,725 | 14,467 | 13,357 |
| Hawaii | 4,327 | 4,280 | 65 | 63 | 3,594 | 3,561 | 799 | 782 |
| Oregon | 1,321 | 1,158 | 931 | 918 | 830 | 677 | 1,421 | 1,399 |
| Washington | 6,703 | 6,590 | 4,074 | 3,924 | 5,574 | 5,481 | 5,203 | 5,034 |
| **U.S. Total** | **374,438** | **367,544** | **89,919** | **81,300** | **232,049** | **228,114** | **232,308** | **220,730** |

1 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.

2 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-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. In addition, since the frame for the Form EIA-867 is derived from utility surveys, the Form EIA-867 universe lags one year.

Notes: •Data for the above years are final. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table 63. Estimated Emissions from U.S. Nonutility Power Producers Facilities by Census Division, 1991 Through 1995 (Thousand Short Tons)

| Census Division | Sulfur Dioxide | Nitrogen Oxides | Carbon Dioxide[1] |
|---|---|---|---|
| | **1991 (5 Megawatts or More)** | | |
| New England | 46 | 38 | 26,464 |
| Middle Atlantic | 95 | 108 | 37,252 |
| East North Central | 193 | 258 | 78,122 |
| West North Central | 69 | 32 | 11,290 |
| South Atlantic | 343 | 199 | 100,603 |
| East South Central | 112 | 62 | 36,647 |
| West South Central | 174 | 245 | 94,953 |
| Mountain | 20 | 26 | 9,777 |
| Pacific Contiguous | 42 | 94 | 46,466 |
| Pacific Noncontiguous | 7 | 9 | 4,277 |
| **U.S. Total** | **1,101** | **1,071** | **445,851** |
| | **1992 (1 Megawatt or More)** | | |
| New England | 39 | 46 | 32,105 |
| Middle Atlantic | 89 | 156 | 49,970 |
| East North Central | 201 | 275 | 84,494 |
| West North Central | 60 | 37 | 13,045 |
| South Atlantic | 384 | 231 | 112,364 |
| East South Central | 119 | 70 | 41,064 |
| West South Central | 237 | 258 | 103,095 |
| Mountain | 21 | 29 | 9,683 |
| Pacific Contiguous | 45 | 102 | 51,545 |
| Pacific Noncontiguous | 13 | 15 | 6,709 |
| **U.S. Total** | **1,208** | **1,219** | **504,074** |
| | **1993 (1 Megawatt or More)** | | |
| New England | 45 | 49 | 33,616 |
| Middle Atlantic | 127 | 168 | 56,669 |
| East North Central | 205 | 307 | 92,877 |
| West North Central | 83 | 42 | 14,235 |
| South Atlantic | 374 | 250 | 118,221 |
| East South Central | 130 | 75 | 45,715 |
| West South Central | 227 | 250 | 102,544 |
| Mountain | 20 | 33 | 10,318 |
| Pacific Contiguous | 44 | 111 | 55,062 |
| Pacific Noncontiguous | 12 | 15 | 6,742 |
| **U.S. Total** | **1,267** | **1,300** | **535,999** |
| | **1994 (1 Megawatt or More)** | | |
| New England | 48 | 48 | 33,809 |
| Middle Atlantic | 124 | 172 | 59,731 |
| East North Central | 291 | 325 | 101,517 |
| West North Central | 68 | 45 | 14,790 |
| South Atlantic | 404 | 273 | 130,675 |
| East South Central | 138 | 78 | 51,625 |
| West South Central | 263 | 233 | 100,721 |
| Mountain | 22 | 37 | 12,015 |
| Pacific Contiguous | 52 | 109 | 55,089 |
| Pacific Noncontiguous | 14 | 15 | 7,309 |
| **U.S. Total** | **1,424** | **1,335** | **567,281** |
| | **1995 (1 Megawatt or More)** | | |
| New England | 45 | 65 | 40,427 |
| Middle Atlantic | 118 | 206 | 61,567 |
| East North Central | 227 | 295 | 89,212 |
| West North Central | 77 | 45 | 16,020 |
| South Atlantic | 380 | 299 | 135,217 |
| East South Central | 94 | 68 | 43,405 |
| West South Central | 194 | 242 | 93,766 |
| Mountain | 26 | 61 | 17,514 |
| Pacific Contiguous | 44 | 140 | 51,453 |
| Pacific Noncontiguous | 12 | 19 | 7,743 |
| **U.S. Total** | **1,217** | **1,440** | **556,324** |

[1] As of 1993 data, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been changed--historical estimates were revised to reflect that change--See Technical Notes for more information.

Notes: •Estimates for 1995 are preliminary; estimates for prior years are final. •Historical data have been revised to reflect a change in methodology--see Technical Notes for more information. •Totals may not equal sum of components because of independent rounding. •See Appendix A, ''Technical Notes,'' for methodology.

Source: Estimated using data from the Form EIA-867, ''Annual Nonutility Power Producer Report.''

# Appendix A

## Technical Notes

# Appendix A

# Technical Notes

## Sources of Data

The *Electric Power Annual Volume II* is prepared by the Coal and Electric Data and Renewables 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 six 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-867, "Annual Nonutility Power Producer Report"; 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 3,200 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. Investor-Owned Electric Utilities;* the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities;* the *Annual Energy Outlook;* the *U.S. Electric Utility Demand-Side Management;* and the *Electric Trade in the United States.* These reports present aggregate totals for electric utilities on national, State, and regional levels by ownership type.

Demand-side management data collected on the Form EIA-861 are estimated by electric utilities based on engineering data or statistical analysis. The utilities also use a variety of verification methodologies for these estimates. The Energy Policy Act (EPACT) of 1992, Section 171(a), mandated that EIA verify DSM data estimates and the methodologies used for estimation and verification. In response to this mandate, EIA conducted a study of DSM estimation methodologies and DSM verification methodologies. The report describes typical estimation methodologies and DSM verification methodologies, as well as the difficulties in reaching broad conclusions concerning the quality of savings estimates reported to EIA. The report is featured in the EIA publication, *U.S. Electric Utility Demand-Side Management 1993*, released in July 1995.

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

*Data Processing.* 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 3 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 emgawatthours 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 has determined that seven independent power producers (IPP's): Catalyst Old River Hydroelectric Limited Partnership, Entergy Power Incorporated, Hardee Power Partners Limited, Medina Power Company, Nevada Sun-Peak Limited Partnership, Ocean State Power, and Ocean State Power II are under FERC jurisdiction. These IPP's must therefore submit the FERC Form 1. The FERC has also determined that Golden Spread Electric Cooperative, Midewest Energy, Incorporated, Old Dominion Electric Cooperative, People's Electric Cooperative, and Rayburn Country Electric Cooperative should file a FERC Form 1 under Section 201 of the Federal Power Act. Data from these five entities were not included since they are classified as cooperative electric utilities on the Form EIA-861.

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;* 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.

## 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 120,000 megawatthours of sales to ultimate consumers and/or 120,000 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 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 Coal and Electric Data and Renewables 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, the FERC, the Environmental Protection Agency, and the Department of Commerce.

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-767 are also contained in the *Electric Power Annual Volume I;* and the *Coal Industry Annual*. 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-867

The Form EIA-867 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, "Standard Industrial Classification Code Designation"; 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-867 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. The Federal Energy Administration Act of 1984 (Public Law 93-275) defines the legislative authority to collect these data.

*Data Processing.* The Form EIA-867 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 that addresses were confirmed was 100 percent. 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 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 1991 through 1995 presented in this report, are reasonable given the growth in manufacturing on site generation.

Data for the Form EIA-867 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. Since the Form EIA-867 data are considered confidential, 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.

*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 (even if a secondary fuel is burned).
- 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.

A comparison of installed capacity for facilities of 1 megawatts or more of EIA's data with data published by Edison Electric Institute (EEI) in *Capacity and Generation of Non-Utility Sources of Energy* shows a difference of approximately 1 percent.

*Gross-to-Net Generation Conversion Methodology.* Gross electricity generation data from the Form EIA-867, 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-867, 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-867. The difference between gross and net generation 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. The difference between gross and net generation is sometimes called parasitic load. 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 a coal pulverizers, fans, and emission controls. On the other hand, windfarms do consume electricity since automatic, computer-based control systems are used to control blade pitch and speed thereby affecting generator electricity output.

Shown below are the conversion factors used to estimated 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.

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 net generation heat rates by primary fuel and prime-mover. The primary fuel is the predominant energy source for the generator based on fuel consumption at the facility expressed in total Btu by fuel type. The heat rates 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 *TAG--Technical Assessment Guide*, Volume 1: Electricity Supply--1986, Electric Power Research Institute, Palo Alto, California, December 1986. The procedure to estimate the fuel consumed for the production of electricity is to calculate net generation by primary fuel and prime-mover (see gross-to-net generation methodology), multiply the net generation by the appropriate heat rate to obtain total Btu consumed for the production of electricity, and apportion by the total Btu weighted by energy source.

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

*Nameplate Capacity to Summer Capability Conversion Methodology.* Form EIA-867, "Annual Nonutility Power Producer Report," 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 the same methodology shown in this Appendix for the Form EIA-860.

*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.[23] The following is a list from the Form EIA-867 of the main classifications and the category of primary business activity within each classification.

**Agriculture, Forestry, and Fishing**
01 Agriculture production-crops
02 Agriculture production, livestock and animal specialties
07 Agricultural services
08 Forestry
09 Fishing, hunting, and trapping

**Mining**
10 Metal mining
12 Coal mining
13 Oil and gas extraction
14 Mining and quarrying of nonmetallic minerals except fuels

**Construction**
15 to 17

**Manufacturing**
20 Food and kindred products
21 Tobacco products
22 Textile and mill products
23 Apparel and other finished products made from fabrics and similar materials
24 Lumber and wood products, except furniture
25 Furniture and fixtures
26 Paper and allied products (other than 2621 or 2631)
  2621 Paper mills, except building paper
  2631 Paperboard mills
27 Printing and publishing
28 Chemicals and allied products (other than 2819, 2821, 2869, or 2873)
  2819 Industrial Inorganic Chemicals
  2821 Plastics materials and resins
  2869 Industrial organic chemicals
  2873 Nitrogenous fertilizers
29 Petroleum refining and related industries (other than 2911)
  2911 Petroleum refining
30 Rubber and miscellaneous plastic products
31 Leather and leather products
32 Stone, clay, glass, and concrete products (other than 3241)
  3241 Cement, hydraulic
33 Primary metal industries (other than 3312 or 3334)
  3312 Blast furnaces and steel mills
  3334 Primary aluminum
34 Fabricated metal products, except machinery and transportation equipment
35 Industrial and commercial equipment and components except computer equipment
36 Electronic and other electrical equipment and components except computer equipment
37 Transportation equipment
38 Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
39 Miscellaneous manufacturing industries

**Transportation and Public Utilities**
40 Railroad transportation
41 Local and suburban transit and interurban highway passenger transport
42 Motor freight transportation and warehousing
43 United States Postal Service
44 Water transportation
45 Transportation by air
46 Pipelines, except natural gas
47 Transportation services
48 Communications
49 Electric, gas, and sanitary services

**Wholesale Trade**
50 to 51

**Retail Trade**
52 to 59

**Finance, Insurance, and Real Estate**
60 Depository Institutions
61 Nondepository credit institutions
62 Security and commodity brokers, dealers, exchanges, and services
63 Insurance carriers
64 Insurance agents, brokers, and services
65 Real estate
67 Holding and other investment offices

**Services**
70 Hotels
72 Personal services
73 Business services
75 Automotive repair, services, and parking
76 Miscellaneous repair services
78 Motion pictures
79 Amusement and recreation services
80 Health services
81 Legal services
82 Education services
83 Social services
84 Museums, art galleries, and botanical and zoological gardens
86 Membership organizations
87 Engineering, accounting, research, management, and related services
88 Private households
89 Miscellaneous services

**Public Administration**
91 to 97

[23] Office of Management and Budget, *Standard Industrial Classification Manual, 1972,* (Washington, D.C. 1987).

**Other** (explain):

Historically, (Tables 57 and 61) 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. Tables A1 and A2 show the installed capacity and gross generation of electricity by the producing energy group, respectively.

### 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 10 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 ten 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.

*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.

# 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 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," 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

Data reported on the Form EIA-867, "Annual Nonutility Power Producer Report," 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 1995 are preliminary. The data are revised and declared final in the *Electric Sales and Revenue 1995*. A comparison of preliminary versus final annual data at the national level for 1995 will be provided in the *Electric Power Annual Volume II* 1996.
- **U.S. Electric Utility Financial Statistics** Financial data from the Federal Energy Regulatory Commission Form 1 and the Form EIA-412 for 1995 are final.
- **U.S. Electric Utility Environmental Statistics** Data from the Form EIA-767 for 1994 are final. The methodology for calculating emissions of sulfur dioxides, nitrogen oxides, and carbon dioxide has been revised. As a result, final data for 1994 at the national level differ from the preliminary by 10.0 percent for sulfur dioxide, 25.0 percent for nitrogen oxides, and 3.0 percent for carbon dioxide. Data for 1995 are preliminary. A comparison of preliminary versus final data at the national level for 1995 will be provided in the *Electric Power Annual Volume II* 1996.
- **U.S. Electric Power Transactions** All data from the Forms EIA-411 and FE-718R are final. Data from the Form EIA-861 for 1995 are preliminary; Form EIA-861 data for prior years are final. Data from the Form EIA-860 are final.
- **U.S. Electric Utility Demand-Side Management** Data on demand-side management from the Form EIA-861 for 1994 are final. Data for 1995 are preliminary. A comparison of preliminary versus final data at the national level for 1995 will be provided in the *Electric Power Annual Volume II* 1996.
- **U.S. Nonutility Power Producers** Data from the Form EIA-867 for 1991 through 1995 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 gross receipts tax or 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 120,000 megawatthours report their incremental peak load reductions and energy savings for the reporting year (1994), annual peak load reductions and energy savings for the reporting year and first- and fifth-forecast years (1995 and 1999), and direct and indirect utility costs and nonutility cost attributable to DSM programs for all 3 years. Annual and incremental effects for the reporting year are reported by consumer sector (residential, commercial, industrial, other) for each program category (energy efficiency, direct load control, interruptible load, other load management, other DSM programs, and load building). Forecast peak reductions and energy savings are reported by program category with all consumer sectors combined. Utilities with sales to ultimate consumers and sales for resale less than 120,000 megawatthours report incremental peak load reductions and energy savings. They also report total utility cost, total nonutility cost, and total DSM cost for the reporting year and first and fifth forecast years. In years prior to 1992, utilities with sales less than 120,000 megawatthours did not report on DSM activities.

### 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.

# Air Emissions

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

## Utility Air Emissions

The following describes the methodology employed to calculate estimates of $SO_2$, $NO_x$, and $CO_2$ emissions from power plants operated by electric utilities. These air emissions are estimated using information contained on Form EIA-767, "Steam-Electric Plant Operation and Design Report." Form EIA-767 collects information annually for all U.S. power plants with a total existing or planned organic- or nuclear-fueled steam-electric generator nameplate rating of 10 megawatts (MW) or larger. Power plants with a total generator nameplate rating of 100 MW or more must complete the entire form, providing, among other things, information about fuel consumption and quality, legal air emission limits, and flue gas desulfurization (FGD) efficiency. Power plants with a total generator nameplate rating from 10 MW to less than 100 MW complete only part of the form, including information on fuel consumption and FGD sulfur removal efficiency, if applicable.

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

The source of the $SO_2$ and $NO_x$ emission factors, when available, is the Environmental Protection Agency report AP-42, "Compilation of Air Pollutant Emission Factors" (Table A3).[24] Environmental Protection Agency emission factors are based on boiler type, firing configuration, and fuel burned. The methodology for determining emissions of $CO_2$ has been revised since the 1991 publication. Emissions of carbon dioxide for 1992 and prior years have been revised using the set of factors shown in Tables A3 and A4.

In 1992, a special study of the relationship between the heat and carbon content of coal was completed by the Energy Information Administration's Analysis and Systems Division of the Office of Coal, Nuclear, Electric and Alternate Fuels. The hypothesis underlying this study was that the ratio of carbon-to-heat content varies not only by coal rank (i.e., anthracite, bituminous, subbituminous, and lignite), but also by geographic location of the coal. In this study, the hypothesis was tested and the results of the analysis supported the hypothesis. That is, it was concluded from the analysis that coal rank and location of the coal are significant factors in the variation of the ratio of carbon-to-heat content. After this determination, a set of emission factors, by rank and State were derived on the basis of data contained in EIA's Coal Analysis File.[25]

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

The emission factors for $CO_2$ (Table A4) from coal are applied by power plant, based on the rank, amount of coal received, and the State from which the coal originated, as reported in FERC Form 423, "Cost and Quality of Fuels for Electric Utility Plants." Thus, a weighted average emissions factor is obtained by plant and multiplied by the quantity of coal consumed by plant, as reported on Form EIA-767, "Steam-Electric Plant Operation and Design Report," to determine the emissions of $CO_2$. The emission factors for $CO_2$ based on 100-percent combustion of the carbon in the fuel. Since a small percentage of the carbon in the coal is not converted to $CO_2$, this publication assumes 99 percent combustion. The 1 percent of emissions is deducted at the State/National level. The emissions at the State level are based on the State in which the plant is located.

Uncontrolled emissions of $SO_2$ and $NO_x$ do not always accurately depict the quantity of emissions released into the atmosphere because they fail to reflect reductions from control equipment and/or operating technologies. Consequently, controlled emissions are calculated to provide a more accurate estimate of actual utility air emission.

*Controlled Sulfur Dioxide Emissions.* Because of environmental regulations controlling $SO_2$ emissions, many utilities are required to install FGD units at their coal-fired plants.[26] FGD units typically remove between 70 to 90 percent of $SO_2$ from the boiler flue gas although higher removal efficiencies can be achieved. Electric utilities report both sulfur removal efficiency (percent) and their most stringent $SO_2$ emis-

[24] "*Compilation of Air Pollutant Emission Factors*, Vol. 1: Stationary Point and Area Sources (AP-44);" 5th Edition (including Supplement A) Research Triangle Park, North Carolina, January 1996.

[25] For a description of methodology and data use to develop the EIA $CO_2$ emission factors, see B. D. Hong and E. R. Slatick, "Carbon Dioxide Emission Factors for Coal," *Quarterly Coal Report, January-March 1994*, DOE/EIA-0121(94/1Q) (Washington, DC, August 1994), Energy Information Administration.

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

sion limits on the Form EIA-767. To determine controlled $SO_2$ emissions, the uncontrolled emissions are reduced by the annual average removal efficiencies reported on the Form EIA-767. This emission is the controlled emission. As a check, the controlled emission is compared with the most stringent legal limit reported on the Form EIA-767. The controlled emission should be less than the legal limit because research indicates that utilities routinely remove more $SO_2$ than required to assure an operating margin of safety. If the controlled emission is not less than the most stringent legal limit, it implies that the utility is out of legal compliance and could be subject to fines and other penalties.

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

*Sulfur Dioxide Emission Comparison.* Title IV of the Clean Air Act Amendments of 1990 requires annual sulfur dioxide ( $SO_2$) emissions from electric power plants to be reduced 10 million tons below their 1990 level by the year 2010. The Clean Air Act required electric utility units covered under the Acid Rain Program (units 25 megawatts and greater) to be equipped with continuous emission monitoring systems (CEMS). CEMS is the industry standard for measuring and recording hourly $SO_2$, nirogen oxide ( $NO_x$), and carbon dioxide ( $CO_2$) emissions. In 1994, the first 263 utility units covered under the Acid Rain Program were required to install CEMS and submit a year's worth of emissions data to the Environmental Protection Agency (EPA). In 1995, the operators of more than 2,000 additional units were required to measure and report emissions data. EPA published 1994 CEMS emissions data by state and plant in its publication *Acid Rain Program, Emissions Scorecard 1994 (EPA430/R-95-012)* .

Preliminary 1995 CEMS data for about 1,000 power plants was received from EPA just prior to the publication deadline. A comparison was made between $SO_2$emissions data from 719 electric utility plants for which both EPA and EIA collected data for 1995. On a national basis, the data collected by EPA is 5 percent higher than $SO_2$emissions calculated by EIA. When 1995 CEMS data are finalized by EPA, EIA plans to conduct a plant-by-plant comparison of CEMS and EIA-calculated $SO_2$, $NO_x$, and $CO_2$ emissions.

*Controlled Nitrogen Oxide Emissions.* The controlled $NO_x$ emission is calculated by applying the appropriate reduction factor in Table A5. Prior to 1995 for utility boilers with regulated nitrogen oxide emission limits, the annual controlled estimate used was the lesser of the controlled estimate or the annual limitation. When more than one control technology is reported, the highest single reduction factor is used to estimate the annual controlled $NO_x$ emission.

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

A degree of complexity is added to this approach, however, because air emission standards are not reported in consistent units. In some rare instances, emission standards are reported in units that cannot be directly compared with estimated uncontrolled emission rates. Examples of such standards are ones that specify the concentration of $NO_x$ allowed in the flue gas or the ambient concentration of $NO_x$ (parts per million). In cases where these types of standards are reported, the uncontrolled emission estimate is used. Such standards are uncommon, however, and do not significantly affect the results.

*Air Emissions from Small Plants.* The Form EIA-767 does not collect data for generators powered by internal combustion engines, gas turbines, combined cycle units (for example, gas turbines with waste heat boilers), and boilers at steam-electric plants with a total nameplate capacity of less than 10 MW. Accordingly, utility air emission from these generators are not estimated by the methodology. An estimate of air emissions from these generating units based on a similar methodology using 1991 fuel consumption data reported on the Form EIA-759, "Monthly Power Plant Report," was performed. Results of this effort indicate that the emissions of $SO_2$, $NOx$, and $CO_2$ from utility sources not included on the Form EIA-767, are less than 0.1, 1.2, and 1.1 percent, respectively, of total utility air emissions.

## Nonutility Air Emissions

The following describes the methodology employed to calculate estimates of $SO_2$, $NO_x$, and $CO_2$ emissions from power plants operated by nonutilities. The emissions are estimated using information contained on Form EIA-867, "Annual Nonutility Power Producer Report." Form EIA-867 collects information annually from all nonutility power producers with a total generator nameplate rating of 1 megawatt (MW) or more, including cogenerators, small power producers, and other nonutility electricity generators. Facilities with a total generator nameplate rating of 1 MW or more must complete the entire form, providing, among other things, information about fuel consumption and quality. Facilities with a combined nameplate capacity of less than 25 megawatts are not required to complete Schedule V "Facility Environmental Information" of the Form EIA-867.

*Uncontrolled Emissions.* Uncontrolled air pollutant emissions are those emissions that would occur in the absence of any control equipment. Uncontrolled $SO_2$, $NO_x$, and $CO_2$ emissions are determined by multiplying the quantity of fuel burned by an emission factor. An emission factor is the average quantity of a pollutant released from a boiler when a unit of fuel is burned. As with electric utilities, the source of both the $SO_2$ and $NO_x$ emission factors, when available, is the Environmental Protection Agency report AP-42, "Compilation of Air Pollutant Emission Factors."[27] However, the boiler type and firing configuration are not reported on the Form EIA-867 so all boilers are assumed to be large boilers[28] with pulverized coal firing and dry bottoms. For other types of prime movers (for example, gas turbines, combined cycle, and internal combustion engines) the same set of emission factors are used.

The methodology for determining emissions of $CO_2$ from nonutility electric power plants has been revised. The new methodology uses the results of the coal study discussed under "Utility Air Emissions." Based on the coal rank, the quality of coal received and its State of origin, weighted average emission factors are determined by State for electric utility plants. It is assumed that nonutility plants located in the same State as utility plants obtain coal from the same State. The weighted emission factors by State for utility coal-fired plants are multiplied by the coal consumption reported for nonutility plants in the respective State on Form EIA-867.

Uncontrolled emissions of $SO_2$ and $NO_x$ do not always accurately depict the quantity of emissions released into the atmosphere because they fail to reflect reductions from control equipment and operating technologies. Consequently, controlled emissions are calculated to provide a more accurate estimate of actual nonutility air emissions.

*Controlled Sulfur Dioxide Emissions.* The Clean Air Act of 1971 established Federal emission limits for new fossil-fueled steam generators -- 1.2 pounds of $SO_2$ per million Btu of solid fossil fuel consumed and 0.8 pounds for liquid fossil fuels. The Clean Air Act of 1978 established even more stringent sulfur dioxide emission limits. The revised law mandates the installation of flue gas desulfurization (FGD) equipment at some new industrial and commercial facilities built after June 19, 1984, and requires that these facilities remove 90 percent of the $SO_2$ in the flue gases. Nonutilities report whether they have FGD equipment at their facilities and the date of first electrical generation on the Form EIA-867. Air emission limits are based on the date construction began. It is assumed that it takes two years from the start of construction to the date of first electrical generation as reported on the form.

Controlled $SO_2$ emissions are calculated for respondents reporting FGD equipment or fluidized bed combustion. For facilities reporting first electrical generation before August 1973, no reductions are assumed. For facilities reporting first electrical generation between August 1973 and June 1986, the controlled emission is estimated as the lesser of either: the uncontrolled emission, or a weighted average of 1.2 and 0.8 pounds of $SO_2$ per million Btu of solid and liquid fossil fuel consumed, respectively. For facilities reporting first electrical generation after June 1986, the controlled emission is estimated as the lesser of either: the uncontrolled emission reduced by 90 percent, or a weighted average of 1.2 and 0.8 pounds of $SO_2$ per million Btu of solid and liquid fossil fuel consumed, respectively.

Facilities with a total nameplate rating between 5 MW and 25 MW are not required to report whether they have FGD units. Controlled $SO_2$ emissions for these facilities are calculated based on the year electricity was first generated at the facility as reported on the Form EIA-867. For facilities reporting electrical generation before August 1973, no control equipment is assumed and the controlled $SO_2$ emission is equal to the uncontrolled emission as calculated above. For facilities reporting the date of their first electrical generation as between August 1973 and August 1980, the controlled $SO_2$ emission is estimated as the lesser of either: the uncontrolled $SO_2$ emission, or 1.2 pound of $SO_2$ per million Btu of fuel consumed. For facilities reporting their first electrical generation after August 1980, the controlled $SO_2$ emission is estimated as the lesser of either: the uncontrolled emission reduced by 80 percent, or 1.2 pounds of sulfur dioxide per million Btu of fuel consumed.

*Controlled Nitrogen Oxide Emissions.* Nonutilities with a total facility nameplate rating of 25 MW or more are required to report on the Form EIA-867 whether they have any $NO_x$ control equipment and its type. Controlled $NO_x$ emissions estimates are based on assumed removal efficiencies for the different types of $NO_x$ control equipment. The percent removal efficiencies of the $NO_x$ control equipment and/or operating technologies are shown in Table A5.

The controlled $NO_x$ emission is calculated by reducing the uncontrolled emission by the appropriate reduction percentage based on the $NO_x$ technology. In cases where more than one type of technology is reported, the highest single reduction percentage of the equipment reported is applied.

Facilities with a total nameplate rating between 5 MW and 25 MW are not required to report whether they have $NO_x$ reduction equipment. However, the Clean Air Act limits $NO_x$ emissions to 0.8 pounds per million Btu of fuel consumed. Controlled $NO_x$ emissions for these facilities are calculated based on the year electricity was first generated at the facility as reported on the Form EIA-867. For facilities reporting electrical generation before August 1973, no control equipment is assumed and the controlled $NO_x$ emis-

[27] "*Compilation of Air Pollutant Emission Factors* , Vol. I: Stationary Point and Area Sources(AP-42)," 5th Edition (including Supplement A) Research Triangle Park, North Carolina, January 1996.

[28] Boilers with a gross heat rate of 100 million Btu per hour or greater.

sion is estimated to be equal to the uncontrolled emission as calculated above. For facilities reporting the first date of electrical generation after August 1973, the controlled $NO_x$ emission is estimated as the lesser of either: the uncontrolled $NO_x$ emission, or 0.8 pounds of $NO_x$ per million Btu of fuel consumed.

*Controlled Carbon Dioxide Emissions.* There are no Federal regulations that limit $CO_2$ emissions. Information pertinent to the estimation of controlled $CO_2$ emissions is not collected on the Form EIA-867; therefore, no estimates of controlled $CO_2$ emissions are provided.

# General Information

## *Use of the Glossary*

The terms in the glossary have been defined for general use. Restrictions on the definitions, as used in these data collection systems, are included in each definition when necessary to define the terms as they are used in this report.

## *Obtaining Copies of Data*

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## Table A1. Installed Capacity at U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1993 through 1995

(Megawatts)

| Census Division | Manufacturing | Transportation and Public Utilities | Services | Mining | Public Administration | Other Industry Groups | Total |
|---|---|---|---|---|---|---|---|
| | | | **1993 (1 Megawatt or More)** | | | | |
| New England | 1,692 | 2,919 | W | — | W | — | 4,729 |
| Middle Atlantic | 2,945 | 5,409 | 295 | — | W | W | 8,730 |
| East North Central | 3,015 | 2,141 | 267 | W | W | W | 5,546 |
| West North Central | 702 | 184 | 165 | W | W | W | 1,261 |
| South Atlantic | 5,715 | 4,405 | 84 | W | W | 61 | 10,303 |
| East South Central | 1,676 | 18 | W | W | W | — | 1,734 |
| West South Central | 10,175 | 2,512 | 203 | 180 | — | — | 13,069 |
| Mountain | 431 | 989 | 77 | 245 | — | 278 | 2,020 |
| Pacific | 3,541 | 8,137 | 236 | 1,142 | 239 | 91 | 13,385 |
| **U.S. Total** | **29,892** | **26,714** | **1,444** | **1,860** | **297** | **571** | **60,778** |
| | | | **1994 (1 Megawatt or More)** | | | | |
| New England | 1,455 | 3,322 | 118 | — | — | — | 4,895 |
| Middle Atlantic | 3,311 | 8,170 | W | — | W | W | 11,752 |
| East North Central | 3,059 | 2,492 | 272 | W | W | W | 5,947 |
| West North Central | 706 | 213 | 166 | W | W | W | 1,296 |
| South Atlantic | 6,114 | 6,027 | 102 | W | W | 67 | 12,384 |
| East South Central | 2,029 | 18 | W | 27 | W | — | 2,088 |
| West South Central | 10,604 | 2,778 | 202 | 180 | — | — | 13,764 |
| Mountain | 425 | 1,602 | 58 | 245 | — | 352 | 2,682 |
| Pacific | 3,206 | 8,706 | 293 | 1,142 | 239 | 68 | 13,654 |
| **U.S. Total** | **30,909** | **33,328** | **1,445** | **1,867** | **330** | **581** | **68,461** |
| | | | **1995 (1 Megawatt or More)** | | | | |
| New England | 1,247 | 3,718 | 72 | — | — | — | 5,037 |
| Middle Atlantic | 2,225 | 10,127 | W | W | — | W | 12,477 |
| East North Central | 3,020 | 2,489 | 323 | W | W | W | 5,917 |
| West North Central | 755 | 137 | 131 | W | W | W | 1,232 |
| South Atlantic | 4,653 | 8,104 | 100 | W | W | 64 | 12,995 |
| East South Central | 1,920 | 127 | W | 27 | W | — | 2,088 |
| West South Central | 9,294 | 4,218 | 202 | 177 | — | — | 13,891 |
| Mountain | 393 | 1,716 | 51 | 245 | — | 352 | 2,757 |
| Pacific | 2,396 | 10,346 | 200 | 644 | 188 | 85 | 13,860 |
| **U.S. Total** | **25,902** | **40,982** | **1,186** | **1,369** | **273** | **541** | **70,254** |

W = Withheld to avoid disclosure of individual company data.

Notes: •Data for the above years are final; •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## Table A2. Gross Generation by U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1993 through 1995

(Million Kilowatthours)

| Census Division | Manufacturing | Transportation and Public Utilities | Services | Mining | Public Administration | Other Industry Groups | Total |
|---|---|---|---|---|---|---|---|
| **1993 (1 Megawatt or More)** | | | | | | | |
| New England | 9,833 | 17,930 | 466 | — | (*) | — | 28,229 |
| Middle Atlantic | 16,469 | 30,513 | W | (*) | (*) | W | 48,705 |
| East North Central | 14,763 | 9,981 | 956 | W | W | W | 26,211 |
| West North Central | 2,983 | 341 | 403 | W | W | W | 4,675 |
| South Atlantic | 32,412 | 10,769 | 159 | W | W | W | 43,620 |
| East South Central | 10,531 | 72 | W | W | W | (*) | 10,741 |
| West South Central | 61,708 | 16,627 | 611 | 1,127 | — | — | 80,073 |
| Mountain | 2,443 | 5,701 | W | 523 | — | W | 9,572 |
| Pacific | 20,704 | 41,692 | 1,407 | 7,720 | 1,530 | 346 | 73,400 |
| **U.S. Total** | **171,845** | **133,627** | **5,541** | **10,689** | **1,767** | **1,757** | **325,226** |
| **1994 (1 Megawatt or More)** | | | | | | | |
| New England | 7,840 | 21,613 | 471 | — | (*) | — | 29,925 |
| Middle Atlantic | 17,948 | 37,167 | W | (*) | W | W | 56,457 |
| East North Central | 14,728 | 12,762 | 993 | W | W | W | 28,993 |
| West North Central | 3,150 | 434 | 421 | W | W | W | 5,077 |
| South Atlantic | 35,043 | 16,720 | 166 | W | W | W | 52,152 |
| East South Central | 12,478 | 81 | W | 148 | W | (*) | 12,786 |
| West South Central | 62,636 | 18,351 | 539 | 464 | — | — | 81,989 |
| Mountain | 2,473 | 7,199 | 336 | 563 | — | 701 | 11,273 |
| Pacific | 19,485 | 45,193 | 1,720 | 8,069 | 1,523 | 281 | 76,271 |
| **U.S. Total** | **175,782** | **159,520** | **5,781** | **10,618** | **1,747** | **1,477** | **354,925** |
| **1995 (1 Megawatt or More)** | | | | | | | |
| New England | 6,581 | 22,593 | 175 | — | — | — | 29,350 |
| Middle Atlantic | 12,831 | 56,428 | 419 | W | — | W | 69,768 |
| East North Central | 14,859 | 12,134 | 1,159 | W | W | W | 28,436 |
| West North Central | 3,025 | W | W | W | W | W | 4,702 |
| South Atlantic | 25,931 | 31,284 | 237 | W | W | W | 57,624 |
| East South Central | 11,593 | W | W | 125 | W | (*) | 12,708 |
| West South Central | 57,667 | 24,398 | 614 | 492 | — | — | 83,172 |
| Mountain | 2,190 | 8,455 | 255 | 482 | — | 880 | 12,263 |
| Pacific | 12,714 | 56,952 | 1,022 | 4,338 | 1,104 | 285 | 76,415 |
| **U.S. Total** | **147,392** | **213,784** | **4,196** | **6,440** | **1,217** | **1,408** | **374,438** |

(*) Denotes less than one-half the unit of measure.

Notes: •Data for the above years are final; •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, ''Annual Nonutility Power Producer Report.''

## 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 ton** |
| Bituminous[4] | cyclone | 38.00 x S | 33.8 | See Table A4 |
| | fluidized bed[5] | 39.60 x S | 9.6 | See Table A4 |
| | spreader stoker | 38.00 x S | 13.7 | See Table A4 |
| | tangential | 38.00 x S | 14.4 | See Table A4 |
| | all others | 38.00 x S | 21.7(34) | See Table A4 |
| Subbituminous[4] | cyclone | 35.00 x S | 33.8 | See Table A4 |
| | fluidized bed[5] | 39.60 x S | 9.6 | See Table A4 |
| | spreader stoker | 35.00 x S | 13.7 | See Table A4 |
| | tangential | 35.00 x S | 14.4 | See Table A4 |
| | all others | 35.00 x S | 21.7(34) | See Table A4 |
| Lignite[4] | cyclone | 30.00 x S | 12.50 | See Table A4 |
| | fluidized bed | 10.00 x S | 3.60 | See Table A4 |
| | front/opposed | 30.00 x S | 11.10 | See Table A4 |
| | spreader stoker | 30.00 x S | 5.80 | See Table A4 |
| | tangential | 30.00 x S | 7.30 | See Table A4 |
| | all others | 30.00 x S | 11.10 | See Table A4 |
| Petroleum Coke[6] | fluidized bed[5] | 39.00 x S | 1.80 | 5,680 |
| | all others | 39.00 x S | 18.00 | 5,680 |
| Refuse | all types | 3.46 | 2.69 | 2,344 |
| Wood | all types | 0.08 | 1.50 | 2,100 |
| **Petroleum and Other Liquid Fuels** | | **lbs per $10^3$ gal** | **lbs per $10^3$ gal** | **lbs per $10^3$ gal** |
| Residual Oil[7] | tangential | 162.70 x S | 42.00 | 25,445 |
| | vertical | 162.70 x S | 67.00 | 25,445 |
| | all others | 162.70 x S | 67.00 | 25,445 |
| Distillate Oil[7] | all types | 144.00 x S | 20.00 | 22,572 |
| Methanol | all types | 0.05 | 12.40 | 7,603 |
| Propane (liquid) | all types | 0.05 | 19.00 | 12,500 |
| Coal-Oil Mixture | all types | 185.00 x S | 50.00 | 22,368 |
| **Natural Gas and Other Gaseous Fuels** | | **lbs per $10^6$ cf** | **lbs per $10^6$ cf** | **lbs per $10^6$ cf** |
| Natural Gas | tangential | 0.60 | 275.00 | 120,000 |
| | all others | 0.60 | 550.00 | 120,000 |
| Blast Furnance Gas | all types | 0.60 | 550.00 | 120,000 |
| **Nonutility** | | | | |
| **Coal and Other Solid Fuels** | | **lbs per ton** | **lbs per ton** | **lbs per ton** |
| Anthracite Culm | all types | 39.00 x S | 9.00 | See Table A4 |
| Bituminous[4] | all types | 38.00 x S | 21.70 | See Table A4 |
| Bituminous Gob | all types | 38.00 x S | 21.70 | See Table A4 |
| Subituminous | all types | 35.00 x S | 21.70 | See Table A4 |
| Lignite[4] | all types | 30.00 x S | 11.10 | See Table A4 |
| Lignite Waste | all types | 30.00 x S | 11.10 | See Table A4 |
| Peat | all types | 30.00 x S | 11.10 | See Table A4 |
| Agricultural Waste | all types | 0.08 | 1.20 | 1,560 |
| Black Liquor | all types | 7.00 | 1.50 | 2,725 |
| Chemicals | all types | 7.00 | 1.50 | 2,725 |
| Closed Loop Biomass | all types | 0.08 | 1.50 | 2,100 |
| Internal | all types | 0.08 | 1.50 | 2,100 |

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 ton** |
| Liquid Acetonitrile Waste | all types | 7.00 | 1.50 | 2,725 |
| Liquid Waste | all types | 7.00 | 1.50 | 2,725 |
| Municipal Solid Waste | all types | 3.46 | 2.69 | 2,344 |
| Petroleum Coke[7] | all types | 39.00 x S | 18.00 | 5,680 |
| Pitch | all types | 30.00 x S | 11.10 | See Table A4 |
| Railroad Ties | all types | 0.08 | 1.50 | 2,100 |
| Red Liquor | all types | 7.00 | 1.50 | 2,725 |
| Sludge | all types | 2.80 | 5.00 | 2,100 |
| Sludge Waste | all types | 2.80 | 5.00 | 2,100 |
| Sludge Wood | all types | 2.80 | 5.00 | 2,100 |
| Spent Sulfite Liquor | all types | 7.00 | 1.50 | 2,725 |
| Straw | all types | 0.08 | 1.50 | 2,100 |
| Sulfur | all types | 7.00 | 0.00 | 0 |
| Tar Coal | all types | 30.00 x S | 11.10 | See Table A4 |
| Tires | all types | 38.00 x S | 21.70 | 5,715 |
| Waste Byproducts | all types | 3.46 | 2.69 | 2,344 |
| Waste Coal | all types | 38.00 x S | 21.70 | See Table A4 |
| Wood/Wood Waste | all types | 0.08 | 1.50 | 2,100 |
| **Petroleum and Other Liquid Fuels** | | **lbs per $10^3$ gal** | **lbs per $10^3$ gal** | **lbs per $10^3$ gal** |
| Heavy Oil[7] | all types | 162.70 x S | 67.00 | 25,445 |
| Light Oil[7] | all types | 162.70 x S | 20.00 | 22,572 |
| Diesel | all types | 162.70 x S | 20.00 | 22,572 |
| Kerosene | all types | 162.70 x S | 20.00 | 22,572 |
| Butane (liquid) | all types | 0.60 | 21.00 | 14,700 |
| Fish Oil | all types | 0.50 | 12.40 | 7,603 |
| Methanol | all types | 0.50 | 12.40 | 7,603 |
| Oil Waste | all types | 147.00 x S | 19.00 | 20,000 |
| Propane (liquid) | all types | 0.50 | 19.00 | 12,500 |
| Sludge Oil | all types | 147.00 x S | 19.00 | 20,000 |
| Tar Oil | all types | 162.70 x S | 67.00 | 25,445 |
| Waste Alcohol | all types | 0.50 | 12.40 | 7,603 |
| **Natural Gas and Other Gaseous Fuels** | | **lbs per $10^6$ cf** | **lbs per $10^6$ cf** | **lbs per $10^6$ cf** |
| Natural Gas | all types | 0.60 | 550.00 | 120,000 |
| Butane (gas) | all types | 0.60 | 550.00 | 479,450 |
| Hydrogen | all types | 0.00 | 550.00 | 0 |
| Landfill Gas | all types | 0.60 | 550.00 | 120,000 |
| Methane | all types | 0.60 | 550.00 | 116,436 |
| Other Gas | all types | 0.60 | 550.00 | 120,000 |
| Propane (gas) | all types | 0.60 | 550.00 | 358,333 |

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 A5 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 = U.S. 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 (including supplement A), Research Triangle Park, North Carolina, January, 1996. •For carbon dioxide factors: Department of Energy, ''Carbon Dioxide Emissions from Fossil Fuels: A Procedure for Estimation of Results, 1950-1981,'' June 1983.

## 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, Office of Coal, Nuclear, Electric, and Alternate Fuels.

## Table A5. Nitrogen Oxide Reduction Factors

| Nitrogen Oxide Control Technology | EIA-767 Code(s) | EIA-867 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 A6. 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 monthly revenue by the corresponding total monthly 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 $1 \times 10^{-4}$ 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.

**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.

**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 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 ten regional reliability councils and encompasses essentially all the power regional of the contiguous United States, Canada, and Mexico. The NERC Regions are:

ASCC - Alaskan System Coordination Council

ECAR - East Central Area Reliability Coordination Agreement

ERCOT - Electric Reliability Council of Texas

MAIN - Mid-America Interconnected Network

MAAC - Mid-Atlantic Area Council

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

**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.

**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 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 Authority Service 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.

**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.

**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.