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Volume II

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Contacts

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

Questions of a general nature should be directed to:
Robert Schnapp (202/426-1211)
Director, Electric Power Division;
Internet e-mail: robert.schnapp@eia.doe.gov

Contributions to this report were provided by the following employees of the Electric Power Division (fax number 202/426-1311):

Volume II Publication Coordinator:

Jerome A. Sanderson (202/426-1162),
Internet e-mail: jerome.sanderson@eia.doe.gov;

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

Jerome A. Sanderson (202/426-1162),
Internet e-mail: jerome.sanderson@eia.doe.gov;
Roger Sacquety (202/426-1160),
Internet e-mail: roger.sacquety@eia.doe.gov;

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

U.S. Electric Utility Financial Statistics:

Jerome A. Sanderson (202/426-1162) Investor,
Internet e-mail: jerome.sanderson@eia.doe.gov;
Charlene Harris-Russell (202/426-1163) Public,
Internet e-mail:
charlene.harris-russell@eia.doe.gov;
Thomas S. Williams (202/426-1267) Public,
Internet e-mail: thomas.williams@eia.doe.gov;

U.S. Electric Utility Environmental Statistics:

Stephen R. Scott (202/426-1149),
Internet e-mail: sscott@eia.doe.gov;
Natalie Ko (202/426-1697),
Internet e-mail: natalie.ko@eia.doe.gov;

U.S. Electric Power Transactions:

Linda Bromley (202/426-1164),
Internet e-mail: linda.bromley@eia.doe.gov;
Rodney Dunn (202/426-0005),
Internet e-mail: rodney.dunn@eia.doe.gov;

U.S. Electric Utility Demand-Side Management:

Karen McDaniel (202/426-1234),
Internet e-mail: karen.mcdaniel@eia.doe.gov;

U.S. Nonutility Power Producers:

Betty Williams (202/426-1269),
Internet e-mail: betty.williams@eia.doe.gov;

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 Jerome A. Sanderson at (202/426-1162) or Internet e-mail: jerome.sanderson@eia.doe.gov.

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

Preface

Electric Power Annual, Volumes I and II

The *Electric Power Annual* is published in two volumes. Volume I, released August 2000, contains 1999 data on U.S. electric utility net generation; wholesale trade; fossil fuel consumption, stocks, receipts, and cost; preliminary data on generating capability and planned additions; and estimated retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold. Also included in Volume I is information on net generation and associated generating capability from renewable energy sources and estimates for national-level nonutility data.

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

The *Electric Power Annual 1999, Volume II* presents a summary of electric power industry statistics at national, regional, and State levels. The objective of the publication is to provide industry decisionmakers, government policymakers, analysts, and the general public with historical data that may be used in understanding U.S. electricity markets. The *Electric Power Annual, Volume II* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy.

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

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

The *Electric Power Annual, Volume II* presents an overview of the electric power industry in the United States, and a summary of the key statistics for the reporting year. The chapters present information and data in each specific area: electric utility retail sales, revenue, and average revenue per kilowatthour; financial statistics for major electric utilities; wholesale trade among electric utilities; electric utility environmental statistics; electric utility demand-side management activities; and statistics for nonutility power producers. Monetary values in this publication are expressed in nominal terms.

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

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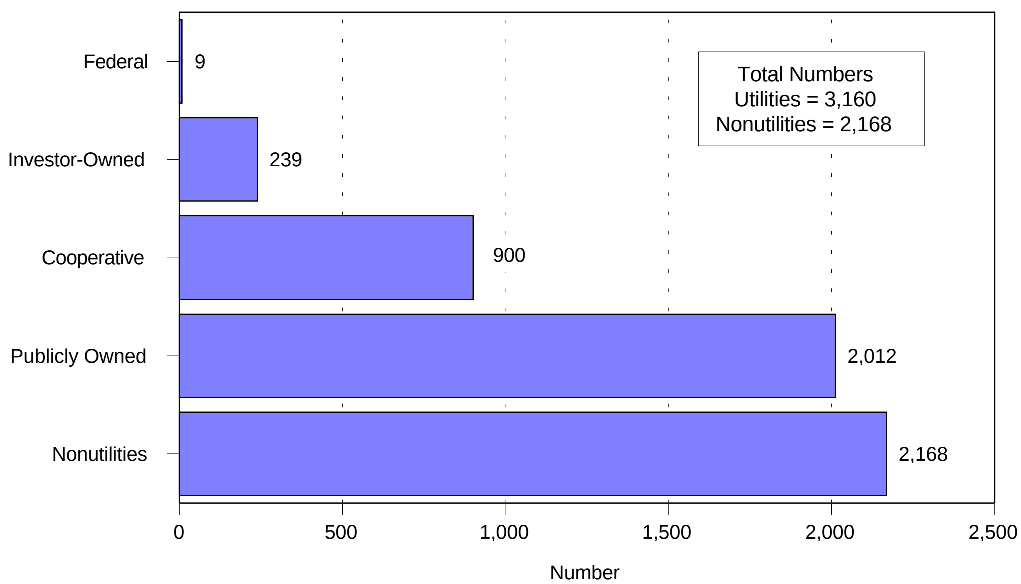
The U.S. Electric Power Industry at a Glance

Industry Profile

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

There are over 3,300 electric utilities (including power marketers) in the United States. Additionally, power marketers, which buy and sell electricity but generally do not own or operate generation, transmission, or distribution facilities, are considered electric utilities. Currently, over 400 power marketers have filed rate tariffs with the Federal Energy Regulatory Commission to sell wholesale electric power. However, fewer than one-third of those actively engaged in wholesale trade. Nonutility power producers are defined as any person, corporation, municipality, State, political subdivision or agency, Federal agency, or other legal entity that is either: (1) a cogeneration qualifying facility under the Public Utilities Regulatory Policies Act of 1978 (PURPA), (2) small power producers qualified under PURPA that provide at least 75 percent of the total energy input in the form of renewable resources, (3) exempt wholesale generators (EWG) under the Energy Policy Act of 1992 (EPACT), (4) cogenerator non-qualifying facilities, and (5) independent power producers (IPP). There are approximately 2,200 nonutility power producers in the United States.

Figure 1. Composition of the Electric Power Industry in the United States, 1999



Notes: •Data are final. •Power marketers, Puerto Rico, and U.S. Territories are not included. •Nonutilities represent the number of generating facilities, as these facilities are generally incorporated, and each is required to file Form EIA-860B.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," Form EIA-860B, "Annual Electric Generator Report – Nonutility."

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

Traditional Electric Utilities

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

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

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

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

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

The number of registered power marketers has grown substantially in the past four years, although in 1999, as in previous years, fewer than one-third of those registered with the FERC actually conducted wholesale electricity transactions. Many registered power marketers undertook only a few transactions, seemingly to test and improve their techniques and procedures and to observe marketplace opportunities.

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

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

Nonutility Power Producers

Cogenerator Qualifying Facilities. These are generating facilities that produce electricity and another form of useful thermal energy, usually heat or steam, for industrial processes, or heating/cooling purposes. Cogenerators are qualified under the Public Utility Regulatory Policies Act of 1978 (PURPA) by meeting certain ownership, operating and efficiency criteria as set forth by the Federal Energy Regulatory Commission (FERC). They are guaranteed that utilities will purchase their output at a price based on the utility's "avoided cost" and will be provided backup service at nondiscriminatory rates.[2]

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

Exempt Wholesale Generators. The Energy Policy Act of 1992 (EPACT) modified the Public Utility Holding Company Act (PUHCA) and created another class of nonutility power producers, exempt wholesale generators (EWG). EPACT exempted EWGs from the corporate and geographic restrictions that PUHCA imposed. With this modification, public utility holding companies are allowed to develop and operate independent power projects anywhere in the world.[3] Lacking transmission facilities and selling wholesale only, EWGs are regulated but usually may charge market-based rates. Utilities are not required to purchase their electricity.

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

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

The Changing Industry

The electric power industry is being transformed from a structure of highly regulated monopolies to one which places growing reliance on competitive markets to establish prices.[4] The implementation of the Energy Policy Act of 1992 (EPACT) by the Federal Energy Regulatory Commission (FERC) and adoption of retail access plans by a growing number of States are introducing greater competition in the generation and retail supply segments of the industry. The EPACT amended the Federal Power Act authorizing the FERC to order public utilities to provide transmission services for competitive wholesale power purchases and sales. Prior to EPACT, the FERC could not mandate an electric utility to provide wheeling services for wholesale electric trade. This change in the law permits generators to make sales for resale to noncontiguous utilities. In 1996, relying on its authority to prevent undue discrimination in the provision of transmission services, the FERC issued Orders 888 and 889, requiring utilities to file open access transmission tariffs. Order 888 guaranteed suppliers and wholesale purchasers access to transmission-owning utilities. Order 888 also provided for utility recovery of costs that may be stranded as a result of open access. Potentially stranded costs are costs that utilities would have had the opportunity to recover at expected market prices.

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

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

Power pools and groups of utilities in most regions of the United States have responded to the FERC rulemakings by proposing the formation of independent system operators (ISO) to ensure nondiscriminatory operation of their transmission

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mergers and acquisitions have been proposed as utilities position themselves for competition. During 1999 there were at least 16 completed and 17 pending significant electric utility merger and acquisition activities. Several are "convergence" mergers, combining electric and gas companies. In December 1996, the FERC revised its merger policy to facilitate decisions on a backlog of merger applications, provide greater certainty to merger applicants, and ensure that merger policies do not impede the development of competitive generation markets. Proponents of mergers cite increased economies of scale through the elimination of duplicate functions, penetration into new and additional customer territory, and the economic and financial advantages that come with increased financial strength and operational size.

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

During 1999, the sale of generating units by utilities to nonutility companies continued to increase. The amount of capability which was sold to nonutilities during 1999 was 50,884 megawatts. Although the effect of the shift from utility to nonutility ownership of generating units was relatively small at the national level, it can be observed more strongly at the State level when restructuring legislation required or encouraged divestiture of the utility's generating assets. This shift in ownership reflects the sale of plants, as well as unit additions and retirements during the year.

Electric utilities added 3,689 megawatts of new capability and retired 427 megawatts during 1999. In addition, nonutility companies added 6,769 megawatts of new capability. Seventy-one percent of this new nonutility capability is gas-fired.

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

A number of States have adopted legislation or approved plans making retail access available to their customers. Pilot programs to initiate and evaluate retail access are being conducted in States where retail access plans are approved or likely to be approved soon. In some jurisdictions, retail access plans face legal challenges related to the recovery of potentially stranded costs and other issues. As of December 1999, 21 States had enacted restructuring legislation. A comprehensive regulatory order had been issued in 3 States. Legislation was either pending, or a commission established, or an investigation was ongoing in the remainder.

A Review of 1999

U.S. Electric Utility Statistics

In 1999, the electric power industry experienced a variety of changes to its sales, finances, power transactions and other industry indicators. The following is a summary of those changes.

Retail Sales and Revenue

Sales of electricity to ultimate consumers by regulated utilities and other energy service providers increased 1.5 percent in 1999 to over 3,312 billion kilowatthours. Sales by traditional utilities providing full service (i.e., both energy and delivery service) decreased slightly from 3,240 billion kilowatthours in 1998 to 3,236 billion kilowatthours in 1999. Sales by competitive energy service providers in State-level "customer choice" programs increased by over 300 percent to 76 billion kilowatthours in 1999. (Further details regarding competitive retail sales in deregulated markets will be provided in *Electric Sales and Revenue 1999*.) Revenue from retail sales by traditional utilities to full-service customers decreased from $218 billion in 1998 to $215 billion in 1999. Reduced revenue receipts for traditional utilities for sales to full-service customers resulted from:

- the large percentage increase in energy sales by competitive suppliers in restructured markets,
- major rate and fuel adjustment caps and reductions in cases affecting large investor-owned utilities in agreements with State regulatory authorities (i.e., Florida, Illinois, and Texas),
- the reallocation to other revenue accounts of retail delivery-service revenue received for service to

customers who selected alternate suppliers in "customer choice" programs, and,

- reduced sales of energy in areas that experienced closer to normal summer weather conditions in 1999 compared to 1998.

The national average revenue in cents per kilowatthour continued to decrease from 6.74 in 1998 to 6.66 in 1999. This is the sixth consecutive year that the national average revenue per kilowatthour has decreased.

On a sectorial basis, sales to residential consumers increased in 1999 by 1.2 percent to 1,141 billion kilowatthours from 1,128 billion kilowatthours in 1998. Sales to the commercial sector increased only 0.2 percent in 1999. The average revenue in cents per kilowatthour for the residential and commercial sectors declined by 1.2 and 2.0 percent to 8.16 and 7.26 percent, respectively. Further reflecting the impact of restructured markets on traditional full-service utilities, industrial sales declined sharply by 2.1 percent to 1,018 billion kilowatthours in 1999 from 1,040 billion kilowatthours in 1998. The average revenue in cents per kilowatthour for industrial sales decreased from 4.48 in 1998 to 4.43 in 1999, a decline of 1.1 percent. Nominal industrial rates in 1999 are the lowest since 1981 and real industrial rates are the lowest since 1973.

The retail sales of investor-owned utilities decreased by 1.2 percent in 1999 while publicly owned utilities increased sales by 2.7 percent and cooperative utilities increased sales by 2.8 percent. Publicly owned and cooperative utilities are not generally affected by various State restructuring programs. Federal sales are primarily in the wholesale market.

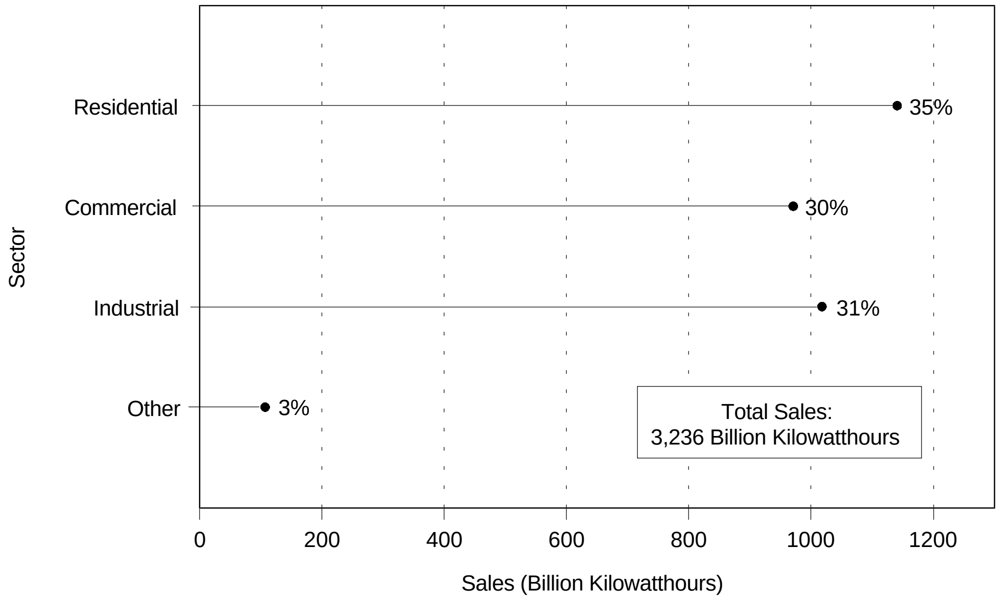
Financial Statistics. Electric operating revenues for the major investor-owned electric utilities were down $4.4 billion to $197.6 billion in 1999. Electric utility operating expenses, led by declines in operation and to maintenance expenses, were also down by a similar amount to $167.3 billion. As a result, electric operating income remained essentially unchanged from 1998. A doubling of extraordinary deductions to $2.8 billion caused net income to decline 1.8 percent to $17.1 billion. Dividends declared on preferred stock continued to decline with the 1999 amount half that reported in 1995. Conversely, common dividends rose 7.3 percent to $18.7 billion. The profit margin remained unchanged at 7.98 percent, while the current ratio of .88 dropped to the 1995 and 1996 levels.

In 1999, the major investor-owned segment continued to position itself in response to restructuring of the industry. Net electric utility plant continued its decline dropping 5.3 percent to $310.3 billion. This is 15.2 percent less than the $366.1 billion reported in 1995. Accumulated depreciation continued its increase to $269.8 billion. Other property and investments increased 11.7 percent, whereas deferred debits dropped 2.2 percent. Current and accrued assets increased 4.4 percent. Total capitalization declined to $345.8 billion primarily due to the $12.0 billion decrease in long-term debt. A $7.2 billion increase occurred in current and accrued liabilities.

In 1999, the major publicly owned generator electric utilities had electric utility operating revenue of $26.8 billion, up by 2.3 percent. Generator electric utility operating expenses increased 1.9 percent, resulting in a decrease in net income ($0.1 billion or 155 million) of 8.0 percent. Total assets for publicly owned generator electric utilities rose ($2.82 billion) ending at $116.3 billion. The electric utility plant per dollar of revenue ratio was 4.0 in 1999.

In 1999, the major publicly owned nongenerator electric utilities had electric utility operating revenue of $9.3 billion, a 6.4-percent growth over 1998. Nongenerator electric utility operating expenses increased by 6.0 percent to end the year at $8.7 billion. Net income for nongenerators increased slightly to $0.6 billion. Total assets for nongenerator electric utilities increased by 8.6 percent to end the year at $13.3 billion. The electric utility plant per dollar of revenue ratio increased to 1.3 in 1999.

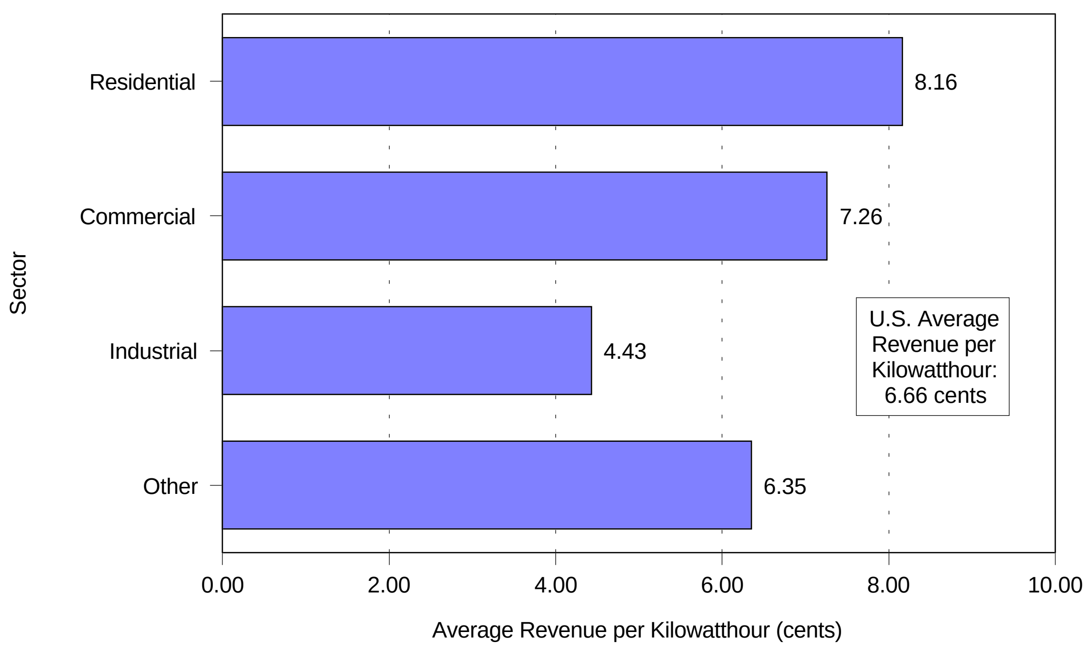
Figure 2. U.S. Electric Utility Sales to Ultimate Consumers by Sector, 1999



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

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

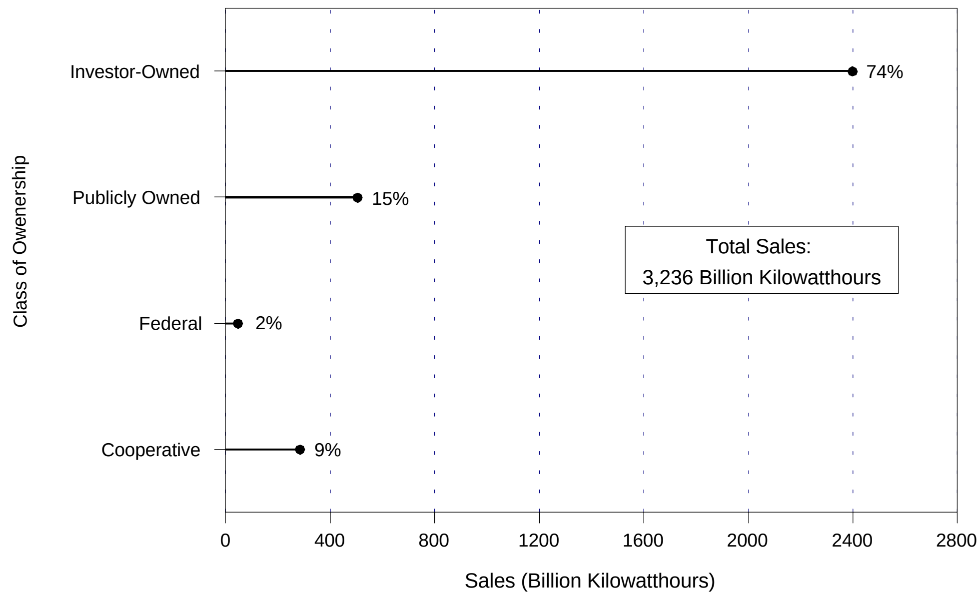
Figure 3. U.S. Electric Utility Average Revenue per Kilowatthour by Sector, 1999



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

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

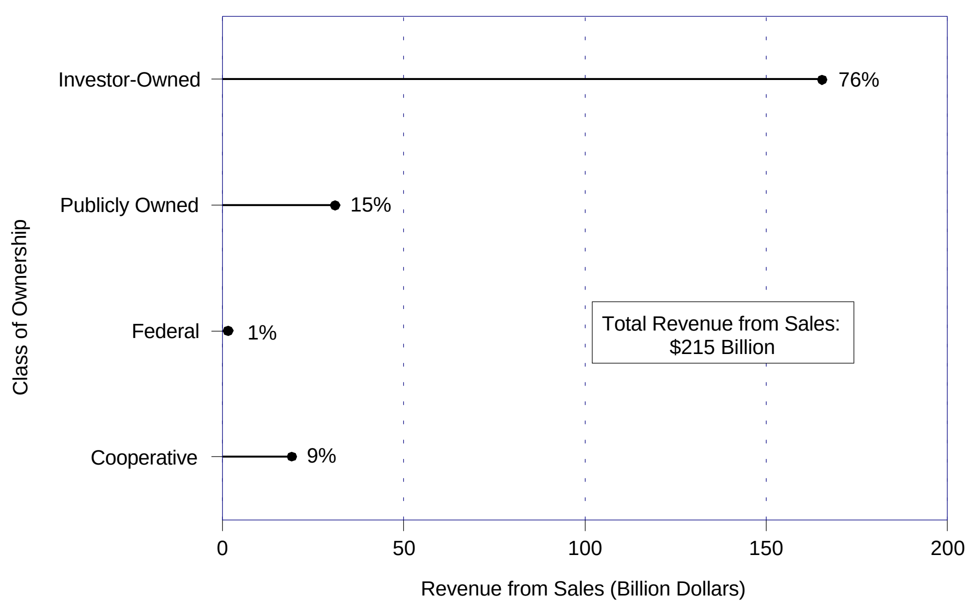
Figure 4. U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1999



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

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

Figure 5. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1999



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

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

Environmental. Air-borne emissions for the electric power industry in the United States (utility plants and nonutility plants) increased overall from 1998 to 1999 (values are expressed in short tons). Sulfur dioxide (SO_2) emissions were up by 2.1 percent, from 13 million tons to 13.3 million tons. Nitrogen oxides (NO_x) emissions rose slightly in 1999 to 7.91 million tons, a rise of 0.1 percent. Carbon dioxide (CO_2) emissions were 3.0 percent greater in 1999, rising from a level of 2,441 million tons in 1998 to about 2,514 million tons in 1999.

In 1999, air emissions from electric utility operated fossil-fueled steam electric plants were estimated to have decreased from the previous year (values are expressed in short tons). Sulfur dioxide (SO_2) emissions were down from 12.4 million tons to about 12 million tons, a decrease of 3.6 percent. Nitrogen oxides (NO_x) emissions decreased from 7.2 million tons to about 7.1 million tons, or 2.2 percent. Carbon dioxide (CO_2) emissions decreased from 2,209 to 2,192 million tons, a drop of 0.8 percent.

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 1999, there were 192 generators connected to scrubbers at U.S. power plants, compared with 186 in 1998 and 150 in 1989. The average sulfur content of coal delivered to all U.S. electric utility plants decreased slightly from 1.06 percent by weight in 1998 to 1.01 percent by weight in 1999.[5]

Air emissions from nonutility plants increased for all three major pollutants. SO_2 emissions showed the greatest increase, rising from 651 thousand tons in 1998 to 1,369 thousand tons in 1999, a rise of 110.3 percent. NO_x emissions rose from 681 thousand tons to 853 thousand tons, an increase of 25.3 percent from the prior year's level. CO_2 emissions increased by 39.4 percent in 1999 to 324 million tons, from 232 million tons in 1998.

Power Transactions. On a national basis in 1999, wholesale power receipts (purchased power plus exchanges received and wheeling received) increased by 50 billion kilowatthours to reach 2,564 billion kilowatthours. Sales to ultimate consumers totaled 3,312 billion kilowatthours (including sales by retail power marketers), and 1,636 billion kilowatthours of this (49 percent) is from wholesale trade with other electric utilities (requirement and nonrequirement sales for resale). To supply electric energy in 2000, electric utilities will have planned capacity resources on-hand for the summer of 766 million kilowatts and 779 million kilowatts for the winter, resulting in national capacity margins of 14.8 percent and 25.7 percent, respectively.

In 1999, the noncoincidental peak load at electric utilities in the contiguous United States showed an increase of 3.2 percent, from 660 to 681 million kilowatts for the summer. The winter peak load was 571 million kilowatts, increasing 3 million kilowatts, which represented a change of less than 1.0 percent. Both the summer and winter peak loads for the contiguous United States are projected for 2000 to grow to 686 and 592 million kilowatts respectively. By the year 2004, the growth in the noncoincidental peak load will be above the 1999 actual by almost 61 million kilowatts for the summer and 67 million kilowatts for the winter.

Imports of electricity in 1999 by electric utilities in the United States increased 3.7 billion kilowatthours to 43 billion kilowatthours, while exports rose 11.7 percent to over 14 billion kilowatthours. Trade with Canada reached 43 billion kilowatthours of imported electricity and nearly 13 billion kilowatthours of exported electricity. Exports to Mexico were up 21.2 percent to almost 1.3 billion kilowatthours. Mexican imports rebounded from the previous year but were only one-quarter the amount reported in 1996. Over half (53.6 percent) of all imports entered the Northeast Power Coordinating Council (NPCC) region. For exports, about 73 percent exited the NPCC and the Western Systems Coordinating Council (WSCC) Regions.

Demand-Side Management. In 1999, 848 electric utilities reported having demand-side management (DSM) programs. Of these, 459 are classified as large, and 389 are classified as small utilities. This is a decrease of 124 utilities from 1998. DSM costs were almost unchanged at 1.4 billion dollars in both 1998 and 1999.

Energy savings for the 459 large electric utilities increased to 50.6 billion kilowatthours, 1.4 billion kilowatthours more than in 1998. These energy savings represent 1.5 percent of total annual electric sales of 3,312 billion kilowatthours to ultimate consumers in 1999.

Actual peak load reductions for large utilities decreased in 1999 to 26,455 megawatts. Potential peak load reductions of 43,570 megawatts were an increase of 2,140 megawatts over 1998.

In 1999, incremental energy savings for large utilities were 3.1 billion kilowatthours, incremental actual peak load reductions were 2,263 megawatts, and incremental potential peak load reductions were 7,151 megawatts.

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

U.S. Nonutility Generating Facility Statistics

Generation. In 1999, U.S. nonutility generating facilities generated 569 billion kilowatthours of electricity. U.S. nonutility generating facilities received 90 billion kilowatthours from, and delivered 413 billion kilowatthours to, electric utilities and other end users. Nonutility power producers delivered approximately 72.4 percent of their gross generation to electric utilities and other end users and used 250 billion kilowatthours for their own power plant operations and industrial processes. Almost one-third of national nonutility production of electricity occurred in California and Texas, with 108 and 69 billion kilowatthours, respectively.

Gross generation for nonutility generating facilities was 35.1 percent higher in 1999 than a year earlier. Slightly more than half of the generation by nonutility generating facilities was gas-fired, with generation from coal accounting for 22.7 percent of the total. Of the total nonutility generation, 335 billion kilowatthours were from qualifying facilities, approximately 43 percent more than 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 Pacific Census Division (Alaska, California, Hawaii, Oregon, and Washington), followed by the Middle Atlantic Census Division (New Jersey, New York, and Pennsylvania), and by the West South Central Census Division (Arkansas, Louisiana, Oklahoma, and Texas). The manufacturing sector dominates electricity generation and is concentrated in the West South Central Census Division, Middle Atlantic Census Division, and South Atlantic Census Division (Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia) where there is a large potential for cogeneration in both the refining and the paper and pulp industries.

Capacity. The total installed capacity of nonutility generating facilities was 167,357 megawatts at the end of 1999, 70.6 percent more than in 1998. The restructuring of the electric power industry has resulted in 23,397 megawatts during 1998 and 50,884 megawatts during 1999 of net summer capability that have been sold (or reclassified) to nonutilities. Nonutility capacity in 1999 was equivalent to 20.7 percent of the total U.S. electric industry capacity.

Of all energy sources, gas and other gas accounted for the largest amount (50,271 megawatts) of nonutility capacity. The Pacific Census Division accounted for 31.2 percent of that gas-fired capacity. The second largest share of nonutility capacity was provided by coal, followed by petroleum only and natural gas.

The greatest number (529) of nonutility generating facilities was in the Pacific Census Division, with a capacity of 33,254 megawatts. In the Pacific Census Division, California dominated because the State actively promoted alternative energy sources in the 1970's and 1980's by providing incentives to nontraditional electricity producers. Many of these incentives have since expired or been rescinded, but they served to assist in the development of nonutility generation. The second greatest number (399) of nonutility generating facilities was in the Middle Atlantic Census Division. Restructuring of the electric power industry has the selling of plants from electric utilities (regulated) to nonutilities (unregulated) in all three States of New York, Pennsylvania, and New Jersey.

Nonutilities plan approximately 22 gigawatts of capacity additions for 2000; 146 gigawatts are planned for 2000 through 2004, with just 2 gigawatts (generator nameplate capacity) planned for 2000 through 2004 by electric utilities. Of the nonutility planned capacity, 82.9 percent is gas-fired.

Consumption. In 1999, consumption by nonutilities included 2,870 billion cubic feet of natural gas, 86 million short tons of coal, and 75 million barrels of petroleum. Compared to 1998, consumption increased 37.7 percent for petroleum, 52.1 percent for coal, and 7.6 percent for gas.

Emissions. In 1999, estimated air emissions from nonutility facilities were 1,369 thousand short tons of SO_2, 850 thousand short tons of NO_x, and 322,625 thousand short tons of CO_2.

Table 1. Electric Power Industry Summary Statistics for the United States, 1998 and 1999

Item	1998	1999	Percent Change
Electric Power Industry[1]			
Generating Capability (megawatts)[2]	775,885	793,957	2.3
Net Generation (million kilowatthours)	3,617,873	3,728,364	3.1
Emissions (thousand short tons)[3]			
Sulfur Dioxide (SO2)	13,064	13,337	2.1
Nitrogen Oxides (NOX)	7,902	7,901	.0
Carbon Dioxide (CO2)[4]	2,441,413	2,514,201	3.0
Electric Utilities			
Generating Capability (megawatts)[2] [5]	[9] 686,692	[9] 639,324	–6.9
Coal	299,739	277,780	–7.3
Petroleum	62,959	49,153	–21.9
Gas	125,386	118,472	–5.5
Hydroelectric Pumped Storage	18,898	18,945	.2
Nuclear	97,070	95,030	–2.1
Waste Heat	4,818	4,808	–.2
Hydroelectric (conventional)	75,525	74,122	–1.9
Other Renewable			
Geothermal	1,550	273	–82.4
Biomass[6]	504	483	–4.2
Wind	9	29	222.2
Photovoltaic	5	5	.0
Net Generation (million kilowatthours)	3,212,171	3,173,674	–1.2
Coal	1,807,480	1,767,679	–2.2
Petroleum[7]	110,158	86,929	–21.1
Gas	309,222	296,381	–4.2
Nuclear	673,702	725,036	7.6
Hydroelectric Pumped Storage[8]	–4,441	–5,982	34.7
Hydroelectric (conventional)	308,844	299,914	–2.9
Other Renewable			
Geothermal	5,176	1,698	–67.2
Biomass[6]	2,024	1,992	–1.6
Wind	3	23	666.7
Photovoltaic	3	3	.0
Consumption			
Coal (million short tons)	911	894	–1.9
Petroleum (million barrels)[10]	179	144	–19.6
Gas (billion cubic feet)	3,258	3,113	–4.5
Stocks (Year End)			
Coal (million short tons)	121	128	–5.8
Petroleum (million barrels)[11]	54	44	–18.5
Receipts			
Coal (million short tons)	929	908	–2.3
Petroleum (million barrels)[12]	165	131	–20.6
Gas (billion cubic feet)[13]	2,924	2,811	–3.9
Cost (cents per million Btu)[14]			
Coal	125.2	121.6	–2.9
Petroleum[15]	213.6	252.7	18.3
Gas	238.1	257.4	8.1
Sales To Ultimate Consumers (million kilowatthours)[16]	3,239,818	3,235,899	–.1
Residential	1,127,735	1,140,761	1.2
Commercial	968,528	970,601	.2
Industrial	1,040,038	1,017,783	–2.1
Other[17]	103,518	106,754	3.1
Revenue From Ultimate Consumers (million dollars)	218,346	215,473	–1.3
Residential	93,164	93,142	.0
Commercial	71,769	70,492	–1.8
Industrial	46,550	45,056	–3.2
Other[17]	6,863	6,783	–1.2
Average Revenue per Kilowatthour (cents)	6.74	6.66	–1.2
Residential	8.26	8.16	–1.2
Commercial	7.41	7.26	–2.0
Industrial	4.48	4.43	–1.1
Other[17]	6.63	6.35	–4.2
Net Electric Plant Inc Fuel (million dollars)			
Major Investor Owned	332,377	314,583	–5.4
Major Publicly Owned Generator/Nongenerator	69,725	70,594	1.2
Emissions (thousand short tons)[18]			
Sulfur Dioxide (SO2)	12,413	11,968	–3.6
Nitrogen Oxides (NOX)	7,221	7,051	–2.4
Carbon Dioxide (CO2)	2,209,281	2,191,576	–.8
Noncoincidental Summer Peak Load (megawatts)	R 660,293	681,449	3.2
DSM Actual Peak Load Reductions (megawatts)	27,231	26,455	–2.8
DSM Energy Savings (million kilowatthours)	49,167	50,563	2.8
DSM Cost (million dollars)	1,421	1,424	.2

Table 1. Electric Power Industry Summary Statistics for the United States, 1998 and 1999 (Continued)

Item	1998	1999	Percent Change
Nonutility Power Producers			
Generating Capability (megawatts)	89,193	154,633	73.4
Coal[19]	12,830	43,957	242.6
Petroleum Only[20]	2,419	3,360	38.9
Gas Only[21]	33,104	45,586	37.7
Petroleum/Natural Gas (combined)	20,848	37,919	81.9
Nuclear	0	1,542	–-
Hydroelectric (conventional)	4,048	5,974	47.6
Other Renewable			
Geothermal	1,367	2,625	92.0
Biomass[6]	9,760	10,527	7.9
Wind	1,689	2,222	31.6
Solar Thermal	385	325	–15.6
Photovoltaic	14	44	214.3
Other[22]	2,768	550	–80.1
Net Generation (million kilowatthours)	405,702	554,690	36.7
Coal[19]	66,466	125,622	89.0
Petroleum[20]	16,775	21,362	27.3
Gas[21]	239,992	297,067	23.8
Nuclear	0	9,066	–-
Hydroelectric (conventional)	14,486	21,530	48.6
Other Renewable			
Geothermal	9,550	15,114	58.3
Biomass[6]	50,988	55,638	9.1
Wind	2,985	4,465	49.6
Solar Thermal	843	790	–6.3
Photovoltaic	10	55	450.0
Other[22]	3,607	3,982	10.4
Consumption			
Coal (million short tons)	57	86	50.9
Petroleum (million barrels)[23]	R 54	75	38.9
Natural Gas (billion cubic feet)	2,666	2,870	7.7
Other Gas (billion cubic feet)[24]	R 873	660	–24.4
Supply and Disposition (million kilowatthours)			
Gross Generation	421,364	569,336	35.1
Receipts[25]	90,675	89,688	–1.1
Deliveries[26]	275,260	412,522	49.9
Facility Use	236,770	250,227	5.7
Emissions (thousand short tons)[27]			
Sulfur Dioxide (SO2)	651	1,369	110.3
Nitrogen Oxides (NOX)	681	850	24.8
Carbon Dioxide (CO2)	232,132	322,625	39.0

1 Electric utility and nonutility values (capability versus capacity, net versus gross generation, total emissions versus emission for the production of electricity) may not be summed directly--see Technical Notes for summation methodology.

2 Data are based on the initial commercial operation year for the generator.

3 In 1998, the useful utility thermal output produced additional emissions of 197 thousand short tons of sulfur dioxide, 62 thousand short tons of nitrogen oxides, and 17,180 thousand short tons of carbon dioxide. In 1999, the useful utility thermal output produced additional emissions of 186 thousand short tons of sulfur dioxide, 65 thousand short tons of nitrogen oxides, and 18,913 thousand short tons of carbon dioxide. In 1998, the useful nonutility thermal output produced additional emissions of 761 thousand short tons of sulfur dioxide, 492 thousand short tons of nitrogen oxides, and 145,486 thousand short tons of carbon dioxide. In 1999, the useful nonutility thermal output produced additional emissions of 675 thousand short tons of sulfur dioxide, 539 thousand short tons of nitrogen oxides, and 179,301 thousand short tons of carbon dioxide.

4 The report, ''Carbon Dioxide Emissions from the Generation of Electric Power in the United States,'' presented carbon dioxide emissions of 2,441,440 thousand short tons in 1998 and 2,474,473 thousand short tons in 1999. The nonutility data were revised since the July 2000, release of that report.

5 Net summer capability based on primary energy source; waste gases, and waste steam are included in the original primary energy source (i.e., coal, petroleum, or gas)--historical data have been revised to reflect this change.

6 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural byproduct, straw, tires, landfill gases, fish oils.

7 Includes petroleum coke.

8 Represents total pumped storage facility production minus energy used for pumping. Negative generation denotes that electric power consumed for plant use exceeds gross generation.

9 For 1999, includes 211 megawatts multi-fueled capacity and 13 megawatts fueled by hot nitrogen; for 1998, includes 216 megawatts multi-fueled capacity and 13 megawatts fueled by hot nitrogen.

10 Does not include petroleum coke consumption of 1,769 thousand short tons in 1998 and 1,608 thousand short tons in 1999.

11 Does not include petroleum coke stocks of 559 thousand short tons at year end 1998 and 355 thousand short tons at year end 1999.

12 Does not include petroleum coke receipts of 3,217 thousand short tons in 1998 and 2,906 thousand short tons in 1999.

13 Includes small amounts of coke-oven, refinery, blast furnance gas, and landfill gas.

14 Average cost of fuel delivered to electric generating plants with a total steam-electric nameplate capacity of 50 or more megawatts; average cost values are weighted by Btu.

15 Does not include petroleum coke cost of 71.2 cents per million Btu in 1998 and 65.4 cents per million Btu in 1999.

16 Not included in retail sales data are sales by power marketers (non-traditional energy service providers) relating to the restructuring of the electric power industry. For 1998 and 1999, these sales were 24.4 million megawatthours and 76.2 million megawatthours, respectively. For more detailed information regarding sales in restructed markets, see the Energy Information Administration's publication, *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year.

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

18 Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. As of 1998, emission factors for the calculation of carbon dioxide emissions have been changed--historical data were revised to reflect that change--see the Technical

Notes for more information.

19 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, lignite waste, tar coal, and waste coal.

20 Includes petroleum, petroleum coke, diesel, kerosene, light oil, liquid butane, liquid propane, oil waste, sludge oil, and tar oil.

21 Includes natural gas, waste heat, butane, propane, and other gas.

22 Includes batteries, chemicals, hydrogen, pitch, purchased steam, and sulfur.

23 Does not include petroleum coke consumption of 4,470 thousand short tons for 1998 and 4,332 thousand short tons for 1999.

24 Includes butane, propane, and other gas,

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

26 Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in these data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-860B is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures contribute to the disparity.

27 In 1998 and 1999, emission factors for the calculation of carbon dioxide and the reductions from nitrogen oxide and sulfur dioxide have been changed--historical data were revised to reflect that change--see technical notes for more information.

R = Revised data.

Notes: •Data previously published has been reclassified by energy source and has been changed to reflect these changes. •Data for 1999 from Form EIA-767 are final pending approval from the Environmental Protection Agency. Other data in this table are final. •See Technical Notes for estimation methodology. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. •DSM = Demand-Side Management.

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

Renewable Energy Resources

Section 171 of Public Law 102-486, the Energy Policy Act of 1992, requires the Administrator of the Energy Information Administration to annually collect and publish the results of a survey of electricity production from domestic renewable energy resources. This requirement includes reporting data on electricity production (in kilowatthours) and total installed capacity. The renewable energy resources shown in Table 1, "Electric Power Industry Summary Statistics for the United States, 1998 and 1999," are reported in detail in the *Renewable Energy Annual, 1999.*

U.S. Electric Utility Retail Sales and Revenue

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

Background

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

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

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

End-Use Sectors

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

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

Revenue Requirements

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

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

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

Average Revenue per Kilowatthour

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

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

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

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

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

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

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

Source of Data

Summary statistics on retail sales of electricity by electric utilities and average revenue are provided in the following tables. These data were obtained from the Form EIA-861, "Annual Electric Utility Report." The form is an annual census of electric utilities (approximately 3,300) that own and/or operate facilities within the United States, its territories, and Puerto Rico.[6] 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*[7]

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

[7] 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 2. U.S. Electric Utility Sales to Ultimate Consumers and Associated Revenue by Sector, 1995 Through 1999

Item	1995	1996	1997	1998	1999
Sales (million kilowatthours)					
Residential	1,042,501	1,082,491	1,075,767	1,127,735	1,140,761
Commercial	862,685	887,425	928,440	968,528	970,601
Industrial	1,012,693	1,030,356	1,032,653	1,040,038	1,017,783
Other[1]	95,407	97,539	102,901	103,518	106,754
U.S. Total	**3,013,287**	**3,097,810**	**3,139,761**	**3,239,818**	**3,235,899**
Revenue (million dollars)					
Residential	87,610	90,501	90,694	93,164	93,142
Commercial	66,365	67,827	70,482	71,769	70,492
Industrial	47,175	47,385	46,772	46,550	45,056
Other[1]	6,567	6,741	7,110	6,863	6,783
U.S. Total	**207,717**	**212,455**	**215,059**	**218,346**	**215,473**

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

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

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

Table 3. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, 1995 Through 1999
(Cents)

Sector	1995	1996	1997	1998	1999
Residential	8.40	8.36	8.43	8.26	8.16
Commercial	7.69	7.64	7.59	7.41	7.26
Industrial	4.66	4.60	4.53	4.48	4.43
Other[1]	6.88	6.91	6.91	6.63	6.35
All Sectors	**6.89**	**6.86**	**6.85**	**6.74**	**6.66**

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

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

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

Table 4. U.S. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1998 and 1999

(Million Kilowatthours)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1998	1999	1998	1999	1998	1999	1998	1999	1998	1999
New England	**110,647**	**111,472**	**38,769**	**40,949**	**44,276**	**43,893**	**26,059**	**25,167**	**1,544**	**1,463**
Connecticut	28,956	29,803	10,935	11,619	11,683	11,834	5,838	5,836	500	515
Maine	11,599	11,944	3,589	3,704	3,324	3,491	4,622	4,687	63	61
Massachusetts	48,607	47,821	16,388	17,392	21,422	20,459	10,212	9,409	585	560
New Hampshire	9,254	9,723	3,384	3,572	3,328	3,512	2,415	2,510	127	128
Rhode Island	6,868	6,655	2,522	2,663	2,731	2,701	1,439	1,137	177	154
Vermont	5,363	5,527	1,951	1,999	1,786	1,896	1,534	1,587	92	45
Middle Atlantic	**325,581**	**296,439**	**104,788**	**108,332**	**120,478**	**106,601**	**85,918**	**67,152**	**14,397**	**14,355**
New Jersey	68,162	70,582	23,191	24,550	31,127	32,436	13,339	13,071	504	525
New York	131,161	129,834	40,240	42,538	53,164	49,366	25,089	25,202	12,669	12,729
Pennsylvania	126,258	96,023	41,358	41,244	36,188	24,799	47,490	28,879	1,223	1,102
East North Central	**545,637**	**560,270**	**160,431**	**165,220**	**147,552**	**154,212**	**222,901**	**225,609**	**14,752**	**15,229**
Illinois	131,217	132,237	39,685	39,623	39,681	41,891	43,031	41,612	8,820	9,111
Indiana	92,059	96,735	27,334	28,806	19,368	20,161	44,848	47,230	509	539
Michigan	100,506	103,480	29,808	30,661	33,840	35,062	35,983	36,808	875	948
Ohio	159,793	164,271	44,516	46,629	38,472	39,461	72,998	74,293	3,807	3,888
Wisconsin	62,061	63,547	19,087	19,502	16,193	17,638	26,040	25,665	741	743
West North Central	**236,377**	**238,073**	**84,066**	**83,516**	**65,601**	**66,343**	**80,826**	**82,445**	**5,885**	**5,769**
Iowa	37,318	38,034	11,855	11,867	8,034	8,269	16,079	16,499	1,350	1,399
Kansas	34,140	33,820	11,832	11,347	12,073	11,822	9,762	10,215	473	436
Minnesota	56,744	57,399	17,378	17,998	10,436	10,909	28,214	27,764	716	729
Missouri	68,986	68,976	28,265	27,766	23,896	24,042	15,801	16,122	1,024	1,046
Nebraska	23,145	22,810	8,160	7,929	6,594	6,661	6,916	6,883	1,475	1,336
North Dakota	8,220	9,112	3,272	3,307	2,305	2,350	2,187	3,013	456	443
South Dakota	7,824	7,922	3,303	3,302	2,263	2,291	1,868	1,949	390	381
South Atlantic	**679,757**	**688,419**	**274,833**	**276,708**	**218,067**	**224,727**	**165,686**	**165,256**	**21,171**	**21,728**
Delaware	10,398	10,494	3,339	3,532	3,227	3,348	3,779	3,559	53	54
District of Columbia	10,281	10,418	1,596	1,643	8,051	8,146	262	249	372	380
Florida	187,355	187,270	95,768	93,846	67,346	69,055	18,448	18,579	5,792	5,790
Georgia	110,720	112,656	41,519	41,767	32,766	34,093	35,077	35,255	1,358	1,541
Maryland	57,834	59,086	22,407	23,342	24,284	24,988	10,344	9,936	799	819
North Carolina	113,596	115,015	42,890	43,648	33,637	35,069	34,986	34,165	2,083	2,133
South Carolina	72,454	73,304	23,558	23,699	16,370	16,585	31,606	32,117	920	903
Virginia	90,609	93,032	34,703	35,779	26,176	26,968	20,024	20,269	9,705	10,017
West Virginia	26,511	27,144	9,053	9,452	6,208	6,473	11,161	11,126	89	92
East South Central	**289,283**	**296,659**	**100,817**	**101,342**	**66,012**	**67,746**	**116,859**	**121,816**	**5,596**	**5,756**
Alabama	79,173	80,401	27,327	27,048	17,662	18,145	33,539	34,533	644	676
Kentucky	75,850	79,098	21,669	22,548	12,729	13,222	38,260	40,054	3,192	3,274
Mississippi	42,510	43,980	16,392	16,321	10,781	11,151	14,599	15,735	738	772
Tennessee	91,750	93,180	35,428	35,425	24,840	25,228	30,461	31,493	1,021	1,035
West South Central	**469,633**	**466,636**	**170,993**	**167,364**	**115,169**	**117,742**	**162,942**	**161,176**	**20,528**	**20,355**
Arkansas	39,315	39,789	14,339	14,045	8,205	8,374	16,066	16,680	705	690
Louisiana	77,716	78,267	26,709	26,426	17,274	17,581	30,999	31,484	2,734	2,776
Oklahoma	47,897	46,737	19,511	18,301	12,459	12,398	13,175	13,271	2,752	2,766
Texas	304,705	301,844	110,434	108,591	77,231	79,388	102,702	99,741	14,337	14,124
Mountain	**206,019**	**210,123**	**64,980**	**67,411**	**64,275**	**67,990**	**68,508**	**66,795**	**8,256**	**7,927**
Arizona	55,843	57,662	21,611	22,517	18,440	19,776	12,549	12,456	3,244	2,912
Colorado	39,574	40,571	12,652	13,131	15,959	17,006	9,998	9,521	965	913
Idaho	21,276	21,846	6,610	6,806	6,005	6,450	8,393	8,295	268	296
Montana	13,774	12,132	3,722	3,664	3,313	3,025	6,403	5,108	335	334
Nevada	25,037	26,253	7,975	8,386	5,655	6,049	10,518	10,861	889	958
New Mexico	18,173	17,998	4,642	4,645	5,703	5,887	6,186	5,922	1,642	1,543
Utah	20,700	21,879	5,756	6,236	6,709	7,282	7,511	7,568	724	792
Wyoming	11,641	11,782	2,013	2,025	2,490	2,514	6,950	7,065	188	178
Pacific	**362,528**	**353,133**	**123,650**	**125,365**	**122,015**	**116,075**	**105,733**	**97,777**	**11,130**	**13,916**
California	226,396	211,981	74,792	74,490	85,678	78,154	58,856	49,595	7,071	9,743
Oregon	45,083	46,996	17,496	18,058	14,103	14,912	13,070	13,558	414	468
Washington	91,050	94,155	31,362	32,817	22,235	23,009	33,807	34,624	3,645	3,706
Pacific Noncontiguous	**14,356**	**14,674**	**4,409**	**4,555**	**5,083**	**5,273**	**4,606**	**4,591**	**259**	**255**
Alaska	5,095	5,293	1,768	1,866	2,307	2,385	818	844	202	198
Hawaii	9,261	9,381	2,641	2,689	2,776	2,887	3,787	3,748	57	57
U. S. Total	**3,239,818**	**3,235,899**	**1,127,735**	**1,140,761**	**968,528**	**970,601**	**1,040,038**	**1,017,783**	**103,518**	**106,754**

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

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in several State ''retail wheeling'' programs. For 1998 and 1999, these sales were 24.4 million megawatthours and 76.2 million megawatthours, respectively. For more detailed information regarding the sales in restructured markets, see the Energy Information Administration's publication, *Electric Sales and Revenue (DOE/EIA-0540)* for the appropriate year. •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, 1998 and 1999

(Thousands)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1998	1999	1998	1999	1998	1999	1998	1999	1998	1999
New England	**6,412**	**6,468**	**5,663**	**5,715**	**676**	**682**	**29**	**29**	**43**	**42**
Connecticut	1,492	1,503	1,351	1,362	130	131	6	6	5	5
Maine	714	724	618	626	75	76	3	3	18	19
Massachusetts	2,805	2,827	2,473	2,496	306	306	14	14	13	11
New Hampshire	616	624	525	532	82	83	3	3	6	6
Rhode Island	465	468	417	419	45	45	3	2	1	1
Vermont	320	322	279	280	39	40	1	*	1	1
Middle Atlantic	**16,474**	**16,209**	**14,529**	**14,312**	**1,842**	**1,800**	**51**	**45**	**52**	**52**
New Jersey	3,506	3,605	3,076	3,148	407	434	13	13	11	11
New York	7,432	7,499	6,545	6,602	846	856	9	9	32	33
Pennsylvania	5,536	5,104	4,908	4,562	589	510	29	24	10	8
East North Central	**20,221**	**20,260**	**18,072**	**18,099**	**1,998**	**2,005**	**73**	**73**	**77**	**83**
Illinois	5,290	5,140	4,751	4,622	506	481	5	5	28	31
Indiana	2,767	2,817	2,462	2,505	278	284	18	18	10	9
Michigan	4,487	4,534	4,024	4,058	441	451	13	14	8	12
Ohio	5,140	5,197	4,582	4,630	509	517	31	30	19	20
Wisconsin	2,537	2,571	2,253	2,283	266	271	6	5	12	12
West North Central	**9,248**	**9,366**	**7,995**	**8,093**	**1,086**	**1,097**	**47**	**51**	**120**	**126**
Iowa	1,402	1,417	1,214	1,229	169	168	4	4	16	17
Kansas	1,315	1,330	1,111	1,118	180	181	11	14	14	17
Minnesota	2,244	2,276	1,988	2,017	222	224	11	11	23	23
Missouri	2,699	2,737	2,373	2,405	302	308	10	10	14	14
Nebraska	874	886	711	718	117	118	8	8	38	41
North Dakota	339	341	285	286	47	48	2	2	5	5
South Dakota	375	380	314	319	49	50	2	2	10	9
South Atlantic	**23,932**	**24,483**	**21,040**	**21,503**	**2,640**	**2,716**	**77**	**77**	**175**	**188**
Delaware	363	370	325	331	37	38	1	1	1	1
District of Columbia	220	220	194	194	26	26	*	*	*	*
Florida	7,771	7,961	6,851	7,001	840	863	24	23	57	74
Georgia	3,623	3,732	3,205	3,296	377	393	12	11	29	32
Maryland	2,147	2,175	1,928	1,952	210	213	8	8	1	1
North Carolina	3,900	4,006	3,384	3,474	481	501	12	13	23	18
South Carolina	1,970	2,012	1,684	1,725	263	267	5	5	18	16
Virginia	3,003	3,063	2,663	2,716	293	299	5	5	42	42
West Virginia	935	944	807	813	114	116	11	11	3	3
East South Central	**8,148**	**8,310**	**7,020**	**7,151**	**1,054**	**1,082**	**20**	**20**	**54**	**58**
Alabama	2,187	2,225	1,873	1,901	296	304	6	6	11	14
Kentucky	1,956	1,991	1,705	1,735	221	227	7	7	22	23
Mississippi	1,320	1,346	1,129	1,152	178	180	5	5	9	9
Tennessee	2,686	2,748	2,312	2,363	360	370	2	2	12	12
West South Central	**13,852**	**14,143**	**12,015**	**12,279**	**1,551**	**1,597**	**127**	**122**	**159**	**146**
Arkansas	1,316	1,339	1,140	1,160	136	140	26	26	14	14
Louisiana	2,018	2,042	1,772	1,791	209	213	15	15	22	22
Oklahoma	1,709	1,729	1,476	1,495	201	204	16	15	16	15
Texas	8,808	9,033	7,627	7,832	1,005	1,041	70	65	107	94
Mountain	**7,877**	**8,070**	**6,767**	**6,950**	**909**	**933**	**41**	**39**	**160**	**148**
Arizona	2,059	2,122	1,830	1,897	194	200	5	5	29	19
Colorado	1,987	2,048	1,662	1,713	227	236	4	3	94	96
Idaho	602	617	503	517	89	91	7	7	3	3
Montana	511	481	419	393	74	69	5	4	13	14
Nevada	830	871	725	760	103	108	1	1	2	1
New Mexico	813	827	697	712	99	102	6	6	10	6
Utah	808	834	716	739	77	81	9	9	5	5
Wyoming	267	271	216	219	45	46	4	4	3	3
Pacific Contiguous	**17,194**	**17,242**	**15,053**	**15,126**	**1,987**	**1,963**	**72**	**72**	**83**	**81**
California	12,941	12,899	11,331	11,327	1,523	1,487	40	41	47	45
Oregon	1,596	1,635	1,376	1,409	198	203	12	12	11	11
Washington	2,657	2,707	2,346	2,390	267	273	20	19	24	24
Pacific Noncontiguous	**683**	**691**	**583**	**591**	**89**	**90**	**1**	**1**	**10**	**10**
Alaska	265	270	223	227	37	37	*	*	5	6
Hawaii	417	422	360	364	52	53	1	1	4	4
U. S. Average	**124,041**	**125,243**	**108,737**	**109,817**	**13,833**	**13,964**	**538**	**527**	**933**	**934**

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

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

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

Table 6. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1998 and 1999
(Million Dollars)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1998	1999	1998	1999	1998	1999	1998	1999	1998	1999
New England	**11,062**	**10,828**	**4,483**	**4,578**	**4,337**	**4,167**	**2,039**	**1,895**	**203**	**188**
Connecticut	2,983	2,968	1,306	1,332	1,169	1,147	449	433	58	56
Maine	1,131	1,167	467	484	343	367	306	301	15	15
Massachusetts	4,659	4,382	1,737	1,755	2,003	1,821	835	729	84	77
New Hampshire	1,104	1,142	471	494	388	400	228	231	17	16
Rhode Island	658	600	275	270	253	229	109	84	20	17
Vermont	527	568	227	243	181	202	112	117	8	6
Middle Atlantic	**30,899**	**27,920**	**12,244**	**12,252**	**12,314**	**10,642**	**4,976**	**3,716**	**1,364**	**1,310**
New Jersey	6,932	7,054	2,642	2,798	3,141	3,160	1,059	1,005	90	91
New York	14,043	13,503	5,496	5,665	6,184	5,523	1,241	1,203	1,121	1,113
Pennsylvania	9,923	7,363	4,106	3,790	2,989	1,959	2,676	1,508	152	106
East North Central	**35,408**	**35,761**	**13,652**	**13,653**	**10,804**	**11,132**	**9,925**	**10,000**	**1,027**	**976**
Illinois	9,792	9,226	3,908	3,500	3,085	3,095	2,199	2,088	600	542
Indiana	4,914	5,117	1,916	2,005	1,177	1,220	1,770	1,840	50	52
Michigan	7,129	7,387	2,584	2,676	2,642	2,755	1,809	1,860	94	96
Ohio	10,198	10,516	3,875	4,046	2,950	3,025	3,142	3,214	231	232
Wisconsin	3,376	3,515	1,369	1,426	951	1,037	1,004	999	52	53
West North Central	**14,019**	**14,100**	**6,152**	**6,146**	**4,040**	**4,057**	**3,459**	**3,529**	**368**	**368**
Iowa	2,255	2,255	993	991	536	533	641	642	84	88
Kansas	2,145	2,102	905	867	766	739	435	457	38	39
Minnesota	3,239	3,344	1,273	1,334	656	688	1,257	1,267	54	55
Missouri	4,195	4,184	2,001	1,976	1,430	1,436	699	707	64	65
Nebraska	1,227	1,212	527	517	359	362	249	246	92	86
North Dakota	469	500	212	215	143	145	94	122	19	19
South Dakota	489	503	240	245	150	153	83	89	17	16
South Atlantic	**43,745**	**43,860**	**21,443**	**21,374**	**14,048**	**14,252**	**6,957**	**6,910**	**1,297**	**1,324**
Delaware	716	747	305	324	228	248	176	168	7	7
District of Columbia	762	777	128	131	598	609	11	11	24	25
Florida	13,127	12,819	7,557	7,253	4,298	4,297	887	886	385	383
Georgia	7,087	7,025	3,185	3,159	2,297	2,272	1,483	1,463	122	130
Maryland	4,045	4,158	1,890	1,959	1,656	1,703	429	423	70	72
North Carolina	7,332	7,412	3,434	3,486	2,137	2,221	1,620	1,560	142	144
South Carolina	4,008	4,085	1,767	1,790	1,021	1,045	1,165	1,196	55	54
Virginia	5,324	5,454	2,608	2,677	1,469	1,498	764	778	484	501
West Virginia	1,345	1,383	570	593	345	358	422	423	8	8
East South Central	**15,257**	**15,482**	**6,502**	**6,507**	**4,103**	**4,161**	**4,305**	**4,466**	**347**	**348**
Alabama	4,404	4,456	1,897	1,901	1,155	1,187	1,306	1,320	47	47
Kentucky	3,155	3,299	1,216	1,257	675	696	1,115	1,196	149	149
Mississippi	2,543	2,486	1,152	1,102	713	690	616	632	62	61
Tennessee	5,155	5,242	2,238	2,247	1,560	1,586	1,269	1,319	89	90
West South Central	**27,849**	**27,566**	**12,695**	**12,334**	**7,395**	**7,518**	**6,484**	**6,468**	**1,275**	**1,247**
Arkansas	2,272	2,262	1,076	1,043	484	488	669	688	42	43
Louisiana	4,490	4,550	1,889	1,882	1,132	1,159	1,288	1,338	181	172
Oklahoma	2,602	2,511	1,282	1,208	705	692	481	478	134	133
Texas	18,486	18,243	8,448	8,201	5,074	5,179	4,047	3,964	917	899
Mountain	**12,210**	**12,372**	**4,897**	**5,015**	**4,116**	**4,265**	**2,766**	**2,677**	**431**	**415**
Arizona	4,092	4,170	1,875	1,922	1,430	1,484	643	628	144	136
Colorado	2,357	2,415	942	969	904	954	433	417	76	75
Idaho	855	870	349	358	261	271	233	228	12	13
Montana	661	607	242	249	195	192	204	145	20	21
Nevada	1,442	1,556	558	598	368	403	480	518	36	38
New Mexico	1,233	1,184	411	401	445	443	277	252	100	89
Utah	1,069	1,064	394	391	383	385	259	254	33	33
Wyoming	502	506	126	128	131	133	235	236	10	9
Pacific Contiguous	**26,318**	**25,943**	**10,526**	**10,690**	**10,051**	**9,712**	**5,224**	**4,969**	**517**	**572**
California	20,439	19,792	7,930	7,978	8,275	7,856	3,876	3,552	358	406
Oregon	2,209	2,287	1,019	1,038	705	737	457	481	28	31
Washington	3,670	3,864	1,577	1,673	1,070	1,119	891	936	132	136
Pacific Noncontiguous	**1,578**	**1,641**	**568**	**593**	**560**	**587**	**415**	**425**	**35**	**35**
Alaska	508	517	203	208	219	219	59	62	28	28
Hawaii	1,070	1,123	365	384	342	368	357	364	7	7
U. S. Total	**218,346**	**215,473**	**93,164**	**93,142**	**71,769**	**70,492**	**46,550**	**45,056**	**6,863**	**6,783**

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

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

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

Table 7. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, Census Division, and State, 1998 and 1999
(Cents)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1998	1999	1998	1999	1998	1999	1998	1999	1998	1999
New England	**10.00**	**9.71**	**11.56**	**11.18**	**9.80**	**9.49**	**7.82**	**7.53**	**13.16**	**12.83**
Connecticut	10.30	9.96	11.95	11.46	10.01	9.69	7.70	7.42	11.65	10.93
Maine	9.75	9.77	13.02	13.07	10.33	10.51	6.61	6.42	23.64	24.29
Massachusetts	9.59	9.16	10.60	10.09	9.35	8.90	8.18	7.75	14.35	13.73
New Hampshire	11.93	11.75	13.92	13.84	11.64	11.39	9.42	9.21	13.76	12.78
Rhode Island	9.58	9.02	10.91	10.13	9.26	8.49	7.61	7.39	11.51	11.20
Vermont	9.83	10.28	11.61	12.17	10.12	10.67	7.27	7.35	8.91	13.32
Middle Atlantic	**9.49**	**9.42**	**11.68**	**11.31**	**10.22**	**9.98**	**5.79**	**5.53**	**9.47**	**9.13**
New Jersey	10.17	9.99	11.39	11.40	10.09	9.74	7.94	7.69	17.92	17.43
New York	10.71	10.40	13.66	13.32	11.63	11.19	4.95	4.77	8.85	8.74
Pennsylvania	7.86	7.67	9.93	9.19	8.26	7.90	5.63	5.22	12.45	9.63
East North Central	**6.49**	**6.38**	**8.51**	**8.26**	**7.32**	**7.22**	**4.45**	**4.43**	**6.96**	**6.41**
Illinois	7.46	6.98	9.85	8.83	7.77	7.39	5.11	5.02	6.80	5.95
Indiana	5.34	5.29	7.01	6.96	6.08	6.05	3.95	3.89	9.83	9.70
Michigan	7.09	7.14	8.67	8.73	7.81	7.86	5.03	5.05	10.74	10.17
Ohio	6.38	6.40	8.70	8.68	7.67	7.67	4.30	4.33	6.07	5.96
Wisconsin	5.44	5.53	7.17	7.31	5.87	5.88	3.86	3.89	7.01	7.11
West North Central	**5.93**	**5.92**	**7.32**	**7.36**	**6.16**	**6.12**	**4.28**	**4.28**	**6.25**	**6.38**
Iowa	6.04	5.93	8.38	8.35	6.67	6.45	3.99	3.89	6.21	6.30
Kansas	6.28	6.22	7.65	7.64	6.34	6.25	4.46	4.47	7.96	8.91
Minnesota	5.71	5.83	7.33	7.41	6.28	6.31	4.45	4.56	7.48	7.49
Missouri	6.08	6.07	7.08	7.12	5.99	5.97	4.43	4.38	6.25	6.26
Nebraska	5.30	5.31	6.46	6.52	5.45	5.44	3.60	3.57	6.27	6.47
North Dakota	5.70	5.49	6.49	6.50	6.20	6.19	4.30	4.04	4.27	4.23
South Dakota	6.26	6.35	7.27	7.42	6.62	6.70	4.44	4.55	4.28	4.17
South Atlantic	**6.44**	**6.37**	**7.80**	**7.72**	**6.44**	**6.34**	**4.20**	**4.18**	**6.13**	**6.10**
Delaware	6.88	7.12	9.13	9.17	7.07	7.39	4.65	4.73	13.17	13.24
District of Columbia	7.41	7.45	8.00	8.00	7.43	7.47	4.38	4.59	6.56	6.55
Florida	7.01	6.85	7.89	7.73	6.38	6.22	4.81	4.77	6.64	6.61
Georgia	6.40	6.24	7.67	7.56	7.01	6.67	4.23	4.15	8.99	8.47
Maryland	6.99	7.04	8.44	8.39	6.82	6.82	4.14	4.26	8.82	8.77
North Carolina	6.45	6.44	8.01	7.99	6.35	6.33	4.63	4.57	6.79	6.74
South Carolina	5.53	5.57	7.50	7.55	6.24	6.30	3.69	3.72	5.99	5.98
Virginia	5.88	5.86	7.51	7.48	5.61	5.55	3.82	3.84	4.98	5.00
West Virginia	5.07	5.09	6.29	6.27	5.56	5.53	3.78	3.80	9.39	9.10
East South Central	**5.27**	**5.22**	**6.45**	**6.42**	**6.22**	**6.14**	**3.68**	**3.67**	**6.20**	**6.04**
Alabama	5.56	5.54	6.94	7.03	6.54	6.54	3.89	3.82	7.26	7.02
Kentucky	4.16	4.17	5.61	5.58	5.30	5.27	2.91	2.99	4.67	4.55
Mississippi	5.98	5.65	7.03	6.75	6.62	6.19	4.22	4.02	8.45	7.93
Tennessee	5.62	5.63	6.32	6.34	6.28	6.29	4.17	4.19	8.71	8.71
West South Central	**5.93**	**5.91**	**7.42**	**7.37**	**6.42**	**6.38**	**3.98**	**4.01**	**6.21**	**6.12**
Arkansas	5.78	5.68	7.51	7.43	5.90	5.82	4.16	4.12	5.98	6.26
Louisiana	5.78	5.81	7.07	7.12	6.56	6.59	4.15	4.25	6.62	6.20
Oklahoma	5.43	5.37	6.57	6.60	5.66	5.58	3.65	3.60	4.88	4.80
Texas	6.07	6.04	7.65	7.55	6.57	6.52	3.94	3.97	6.40	6.36
Mountain	**5.93**	**5.89**	**7.54**	**7.44**	**6.40**	**6.27**	**4.04**	**4.01**	**5.22**	**5.23**
Arizona	7.33	7.23	8.68	8.53	7.76	7.51	5.12	5.04	4.43	4.66
Colorado	5.95	5.95	7.45	7.38	5.67	5.61	4.34	4.38	7.92	8.23
Idaho	4.02	3.98	5.28	5.26	4.34	4.20	2.77	2.74	4.59	4.47
Montana	4.80	5.01	6.50	6.78	5.87	6.35	3.19	2.84	6.07	6.34
Nevada	5.76	5.93	7.00	7.13	6.50	6.66	4.57	4.77	4.02	3.94
New Mexico	6.78	6.58	8.85	8.62	7.80	7.53	4.47	4.25	6.11	5.76
Utah	5.16	4.86	6.84	6.27	5.71	5.29	3.45	3.36	4.50	4.21
Wyoming	4.31	4.30	6.28	6.34	5.25	5.28	3.38	3.34	5.15	5.27
Pacific Contiguous	**7.26**	**7.35**	**8.51**	**8.53**	**8.24**	**8.37**	**4.94**	**5.08**	**4.65**	**4.11**
California	9.03	9.34	10.60	10.71	9.66	10.05	6.59	7.16	5.06	4.16
Oregon	4.90	4.87	5.82	5.75	5.00	4.94	3.50	3.55	6.67	6.68
Washington	4.03	4.10	5.03	5.10	4.81	4.86	2.64	2.70	3.61	3.66
Pacific Noncontiguous	**10.99**	**11.18**	**12.89**	**13.01**	**11.03**	**11.14**	**9.01**	**9.27**	**13.37**	**13.83**
Alaska	9.97	9.78	11.50	11.16	9.48	9.20	7.17	7.32	13.68	14.16
Hawaii	11.56	11.97	13.82	14.30	12.31	12.74	9.41	9.70	12.28	12.66
U. S. Average	**6.74**	**6.66**	**8.26**	**8.16**	**7.41**	**7.26**	**4.48**	**4.43**	**6.63**	**6.35**

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

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

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

U.S. Electric Utility Financial Statistics

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

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

Background

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

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

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

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

Composite Statement of Income

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

Composite Balance Sheet

The balance sheet represents an accounting at a particular time. For this section, the composite balance sheets are presented for major investor-owned electric utilities at the end of a calendar year and for major publicly owned electric utilities for the 12-month fiscal year ending in 1999. 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 1999. Publicly owned electric utilities were responsible for about 10 percent of the total U.S. utility generation, while the remainder was accounted for by Federal and cooperative electric utilities. Operating expenses per unit of output (kilowatthour) for the major investor-owned electric utilities from 1994 through 1998 are provided grouped into the following categories: fossil-fueled steam, nuclear, hydroelectric, and other (includes gas turbine and small scale electric plants).

Data Sources

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

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

Effective for 1997 through 1999, FERC Form 1 data in this publication have been edited by Navigant Consulting, Inc. Detailed data for 1995 through 1996 are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.* This publication has now been discontinued. However, complete 1997 through 1999 FERC Form 1 data may be obtained on a utility-by-utility basis from the FERC World Wide Website (http://www.ferc.fed.us).

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

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

The 1995-1997 data represents those public electric utilities meeting a threshold of 120,000 megawatthours ultimate consumers' sales and or resales. Approximately 500 publicly owned electric utilities are required to submit the Form EIA-412 for 1999. These major publicly owned electric utilities represent about one-fourth of all publicly owned electric utilities. Relating to the major publicly owned utilities, there were 493 respondents in 1999 compared to 487 respondents in 1998. These respondents represent over 85 percent of the sales of electricity to ultimate consumers and over 81 percent of the revenues from the sales to ultimate consumers for all publicly owned electric utilities. These electric utilities are requested, but not required, to follow the FERC Uniform System of Accounts. Detailed financial statistics on public electric utilities, Federal electric utilities, and rural electric cooperatives are published in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities.*[8]

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

Table 8. Composite Statement of Income for Major U.S. Investor-Owned Electric Utilities, 1995 Through 1999
(Thousand Dollars)

Description	1995	1996	1997	1998[1]	1999
Operating Revenue	**199,966,979**	**207,459,078**	**215,082,593**	**218,174,613**	**214,160,472**
Electric	183,655,263	188,900,781	195,897,868	201,970,019	197,577,518
Gas	15,580,382	17,869,394	18,662,611	15,734,812	16,033,291
Other Utility	731,333	688,903	522,114	469,782	549,662
Operating Expenses	**165,321,023**	**173,920,492**	**182,796,184**	**186,497,546**	**182,258,470**
Electric	150,598,710	156,937,816	165,443,479	171,688,890	167,266,172
Operation	91,880,940	97,206,642	104,337,106	110,758,800	108,460,803
Maintenance	11,767,040	12,049,844	12,367,646	12,485,809	12,276,436
Depreciation[2]	19,885,482	21,193,742	23,072,100	24,122,208	23,968,285
Taxes Other Than Income Taxes	13,519,143	13,569,490	13,611,714	12,867,359	12,336,492
Regulatory Debits (net)	1,142,138	683,185	615,575	–455,682	–708,435
Income Taxes	11,479,763	11,194,656	11,862,201	13,037,021	14,843,421
Deferred Income Tax	1,473,977	1,616,998	25,433	–476,064	–2,216,263
Investment Tax Credit (Net)	–549,772	–576,741	–448,296	–650,561	–1,694,568
Gas	14,073,160	16,257,611	16,925,438	14,395,995	14,493,318
Income Taxes	531,748	223,871	584,937	667,681	633,531
Other	13,541,412	16,033,740	16,340,501	13,718,314	13,859,787
Other Utility	649,154	725,066	427,267	412,661	498,980
Income Taxes	5,807	–21,775	1,945	–3,782	–9,568
Other	643,347	746,841	425,321	416,444	508,547
Operating Income	**34,645,955**	**33,538,586**	**32,286,409**	**31,677,067**	**31,902,002**
Electric	33,056,553	31,962,965	30,454,389	30,281,129	30,311,346
Gas	1,507,223	1,611,783	1,737,173	1,338,817	1,539,973
Other	82,180	–36,163	94,847	57,121	50,683
Other Income and Deductions	**1,811,414**	**1,614,287**	**1,813,459**	**1,111,163**	**1,665,449**
Allowance for Other Funds Used During Construction	315,651	230,791	201,208	189,183	203,702
Less Taxes	350,716	597,230	1,006,783	1,741,612	–1,813,496
Deferred Earnings (Misc.) (acct 421)	372,642	774,012	665,506	2,722,008	3,273,402
Less Other Income and Expenses[3]	–1,473,837	–1,206,714	–1,953,528	58,417	3,625,151
Total Income Before Interest Charges	**36,457,369**	**35,152,873**	**34,099,868**	**32,788,230**	**33,567,451**
Net Interest Charges	**14,421,406**	**13,990,388**	**14,085,736**	**14,056,616**	**13,691,495**
Interest Expense	14,169,979	13,645,951	13,767,563	13,670,318	13,376,175
Less Allowance for Borrowed Funds Used During Construction	435,386	326,158	331,057	328,378	330,928
Other Charges--Net	686,814	670,597	649,300	714,675	646,248
Net Income Before Extraordinary Charges	**22,035,963**	**21,162,485**	**20,014,132**	**18,731,615**	**19,875,956**
Less Extraordinary Items After Taxes[3]	**–24,691**	**–65,696**	**3,151,490**	**1,343,507**	**2,793,032**
Net Income	**22,060,655**	**21,228,180**	**16,862,642**	**17,388,108**	**17,082,923**
Dividends Declared - Preferred Stock	**1,518,904**	**1,248,409**	**1,005,367**	**750,305**	**686,774**
Earnings Available for Common Stocks	**20,541,751**	**19,979,771**	**15,857,275**	**16,637,803**	**16,396,150**
Dividends Declared - Common Stock	**16,249,715**	**16,810,054**	**17,756,067**	**17,414,045**	**18,686,752**
Additions Total Earnings	**4,281,899**	**2,193,444**	**–1,959,552**	**–198,753**	**–2,784,590**

1 Data for 1998 have been revised by Navigant Consulting, Inc.
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.

Notes: •Data for 1995 through 1998 are final; whereas data for 1999 are preliminary. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.'' The 1997 through 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 9. Composite Balance Sheet for Major U.S. Investor-Owned Electric Utilities, 1995 Through 1999

(Thousand Dollars)

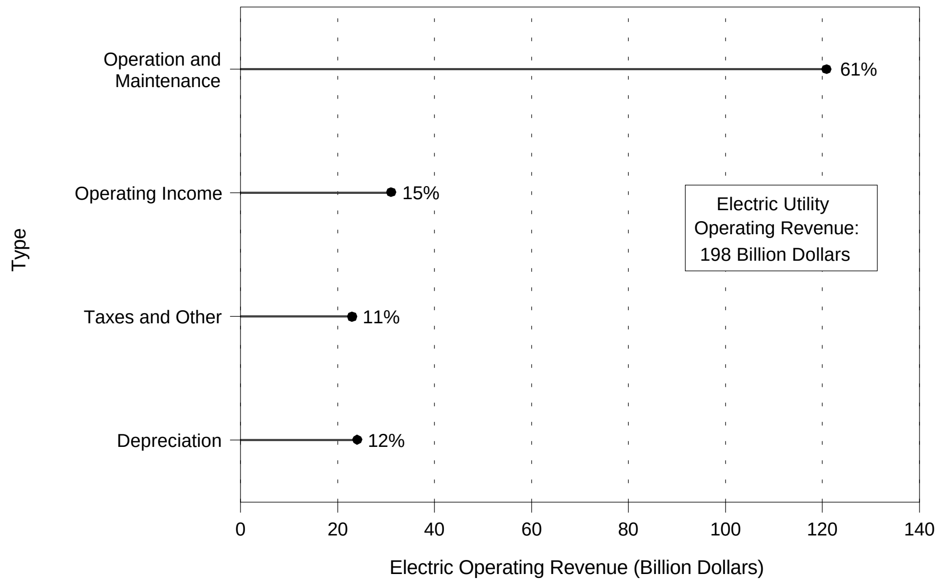
Description	1995	1996	1997	1998[1]	1999
Assets					
Utility Plant - Net	**397,383,148**	**396,437,823**	**385,258,389**	**362,387,812**	**344,111,676**
Electric Utility Plant - Net	366,116,061	363,853,762	351,426,794	327,646,043	310,317,423
Electric Utility Plant	553,857,823	569,968,617	579,042,425	575,651,242	567,824,719
Construction Work in Progress	13,523,358	11,395,525	11,163,637	11,886,399	12,305,936
Less Accumulated Depreciation	201,265,120	217,510,379	238,779,268	259,891,598	269,813,232
Nuclear Fuel - Net	5,285,850	5,443,854	5,218,574	4,731,088	4,265,436
Other Utility Plant - Net	25,981,238	27,140,206	28,613,021	30,010,680	29,528,818
Other Property and Investments	**27,987,677**	**33,119,898**	**43,247,896**	**48,853,135**	**54,546,121**
Current and Accrued Assets	**44,139,661**	**43,515,064**	**47,639,268**	**54,901,305**	**57,324,293**
Deferred Debits	**109,423,227**	**108,918,179**	**110,095,573**	**132,713,547**	**129,844,600**
Total Assets and other Debits	**578,933,714**	**581,990,963**	**586,241,128**	**598,855,799**	**585,826,690**
Capitalization and Liabilities					
Capitalization	**365,774,716**	**365,782,779**	**369,079,448**	**367,052,433**	**345,786,166**
Common Stock Equity (End of Year)	170,497,132	174,325,424	174,467,159	172,239,056	165,340,710
Common Stock	111,301,825	112,633,284	113,889,942	113,200,530	109,187,900
Retained Earnings (Adjusted)	59,195,307	61,692,140	60,577,217	59,038,526	56,152,810
Preferred Stock	21,569,105	18,830,248	16,080,195	14,447,351	12,061,103
Long-term Debt	173,708,479	172,627,107	178,532,093	180,366,026	168,384,353
Current Liabilities and Deferred Credits	**213,158,998**	**216,208,185**	**217,161,680**	**231,803,366**	**240,040,524**
Other Noncurrent Liabilities	14,352,102	15,309,391	17,085,609	18,027,365	19,153,475
Current and Accrued Liabilities	49,929,403	49,341,620	51,594,407	57,591,036	64,777,564
Deferred Credits	148,877,493	151,557,174	148,481,665	156,184,964	156,109,484
Accumulated Deferred Income Taxes	108,615,175	110,537,249	106,393,740	106,405,740	101,171,234
Accumulated Deferred Investment Tax Credit	12,138,942	11,491,332	10,782,506	9,731,454	8,647,413
Other Deferred Credits (Adjusted)	28,123,375	29,528,592	31,305,418	40,047,770	46,290,839
Total Liabilities and Other Credits	**578,933,714**	**581,990,963**	**586,241,128**	**598,855,799**	**585,826,690**

1 Data for 1998 have been revised by Navigant Consulting, Inc.

Notes: •Data for 1995 through 1998 are final; whereas data for 1999 are preliminary. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.'' The 1997 through 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

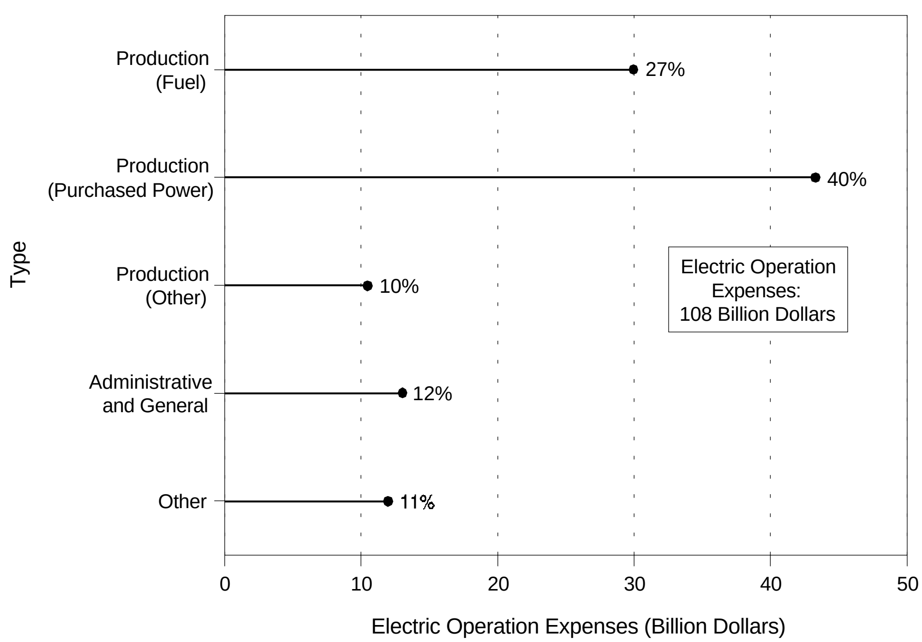
Figure 6. Allocation of the Revenue Dollar from Electric Operations for Major U.S. Investor-Owned Electric Utilities, 1999



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

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." The 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Figure 7. Electric Operation Expenses for Major U.S. Investor-Owned Electric Utilities, 1999



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

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." The 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 10. Composite Financial Indicators for Major U.S. Investor-Owned Electric Utilities, 1995 Through 1999

Description[1]	1995	1996	1997	1998[2]	1999
Activity					
1. Electric Fixed Asset (Net Plant) Turnover	0.50	0.52	0.56	0.62	0.64
2. Total Asset Turnover	.35	.36	.37	.36	.37
Leverage					
3. Current Assets to Current Liabilities	.88	.88	.92	.95	.88
4. Long-term Debt to Capitalization	47.49	47.19	48.37	49.14	48.70
5. Preferred Stock to Capitalization	5.90	5.15	4.36	3.94	3.49
6. Common Stock Equity to Capitalization	46.61	47.66	47.27	46.92	45.98
7. Total Debt to Total Assets[3]	31.89	31.57	32.23	31.97	31.10
8. Common Stock Equity to Total Assets	29.45	29.95	29.76	28.76	28.22
9. Interest Coverage Before Taxes without AFUDC	3.37	3.36	3.33	3.36	3.66
Profitability					
10. Profit Margin	11.03	10.23	7.84	7.97	7.98
11. Return on Average Common Stock Equity[4]	13.17	12.31	9.67	10.03	10.12
12. Return on Investment	3.81	3.65	2.88	2.90	2.92

[1] Indicators 1, 2, 3, and 9 are ratios. Indicators 4 through 8 and 10 through 12 are percentages.
[2] Data for 1998 have been revised by Navigant Consulting, Inc.
[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) $13,802,174,000 for 1999; $11,064,893,000 for 1998; $10,417,018,000 for 1997; $11,129,401,000 for 1996; and $10,895,101,000 for 1995.
[4] The Average Common Stock Equity is the average of the beginning and ending year balances. The value for the beginning of 1995 was $164,482,824,000.

AFUDC=Allowance for Funds Used During Construction.

Notes: •Data for 1995 through 1998 are final; whereas data for 1999 are preliminary. •Formulas for computing the financial indicators are in Appendix A. •Indicators 4, 5, and 6 may not sum to 100 percent because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.'' The 1997 through 1999 data are edited by Navigant Consulting, Inc. 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, 1995 Through 1999

(Thousand Dollars)

Description	1995	1996	1997	1998[1]	1999
Utility Operating Revenues	**199,966,979**	**207,459,078**	**215,082,593**	**218,174,613**	**214,160,472**
Electric Utility	183,655,263	188,900,781	195,897,868	201,970,019	197,577,518
Other Utility	16,311,715	18,558,297	19,184,725	16,204,594	16,582,954
Utility Operating Expenses	**165,321,023**	**173,920,492**	**182,796,184**	**186,497,546**	**182,258,470**
Electric Utility	150,598,710	156,937,816	165,443,479	171,688,890	167,266,172
Operation	91,880,940	97,206,642	104,337,106	110,758,800	108,460,803
Production	68,983,410	73,436,927	80,152,500	85,956,077	83,554,665
Cost of Fuel	29,121,982	30,706,261	31,860,594	31,251,880	29,826,376
Purchased Power	29,981,379	32,987,034	37,990,963	42,611,883	43,258,418
Other	9,880,049	9,743,632	10,300,942	12,092,314	10,469,871
Transmission	1,425,058	1,503,196	1,915,174	2,197,331	2,423,452
Distribution	2,560,835	2,604,058	2,699,803	2,803,526	2,955,635
Customer Accounts	3,613,101	3,848,302	3,767,257	4,021,303	4,194,579
Customer Service	1,922,475	1,920,450	1,197,459	1,955,451	1,889,234
Sales	348,345	435,477	500,934	514,388	492,039
Administrative and General	13,027,716	13,458,234	13,383,979	13,310,724	12,951,199
Maintenance	11,767,040	12,049,844	12,367,646	12,485,809	12,276,436
Depreciation	19,885,482	21,193,742	23,072,100	24,122,208	23,968,285
Taxes and Other	27,065,248	26,487,588	25,666,627	24,322,072	22,560,647
Other Utility	14,722,314	16,982,677	17,352,705	14,808,656	14,992,298
Net Utility Operating Income	**34,645,955**	**33,538,586**	**32,286,409**	**31,677,067**	**31,902,002**

[1] Data for 1998 have been revised by Navigant Consulting, Inc.

Notes: •Data for 1995 through 1998 are final; whereas data for 1999 are preliminary. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.'' The 1997 through 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 12. Revenue and Expense Percentages for Major U.S. Investor-Owned Electric Utilities, 1995 Through 1999

Description	1995	1996	1997	1998[1]	1999
Utility Operating Revenues	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Electric Utility	91.8	91.1	91.1	92.6	92.3
Other Utility	8.2	8.9	8.9	7.4	7.7
Utility Operating Expenses	**82.7**	**83.8**	**85.0**	**85.5**	**85.1**
Electric Utility	75.3	75.6	76.9	78.7	78.1
Operation	45.9	46.9	48.5	50.8	50.6
Production	34.5	35.4	37.3	39.4	39.0
Cost of Fuel	14.6	14.8	14.8	14.3	13.9
Purchased Power	15.0	15.9	17.7	19.5	20.2
Other	4.9	4.7	4.8	5.5	4.9
Transmission	.7	.7	.9	1.0	1.1
Distribution	1.3	1.3	1.3	1.3	1.4
Customer Accounts	1.8	1.9	1.8	1.8	2.0
Customer Service	1.0	.9	.9	.9	.9
Sales	.2	.2	.2	.2	.2
Administrative and General	6.5	6.5	6.2	6.1	6.0
Maintenance	5.9	5.8	5.8	5.7	5.7
Depreciation	9.9	10.2	10.7	11.1	11.2
Taxes and Other	13.5	12.8	11.9	11.1	10.5
Other Utility	7.4	8.2	8.1	6.8	7.0
Net Utility Operating Income	**17.3**	**16.2**	**15.0**	**14.5**	**14.9**

[1] Data for 1998 have been revised by Navigant Consulting, Inc.

Notes: •Data for 1995 through 1998 are final; whereas data for 1999 are preliminary. •Percents in this table are percentage of utility operating revenues. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.'' The 1997 through 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 13. Average Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1995 Through 1999

(Mills per Kilowatthour)

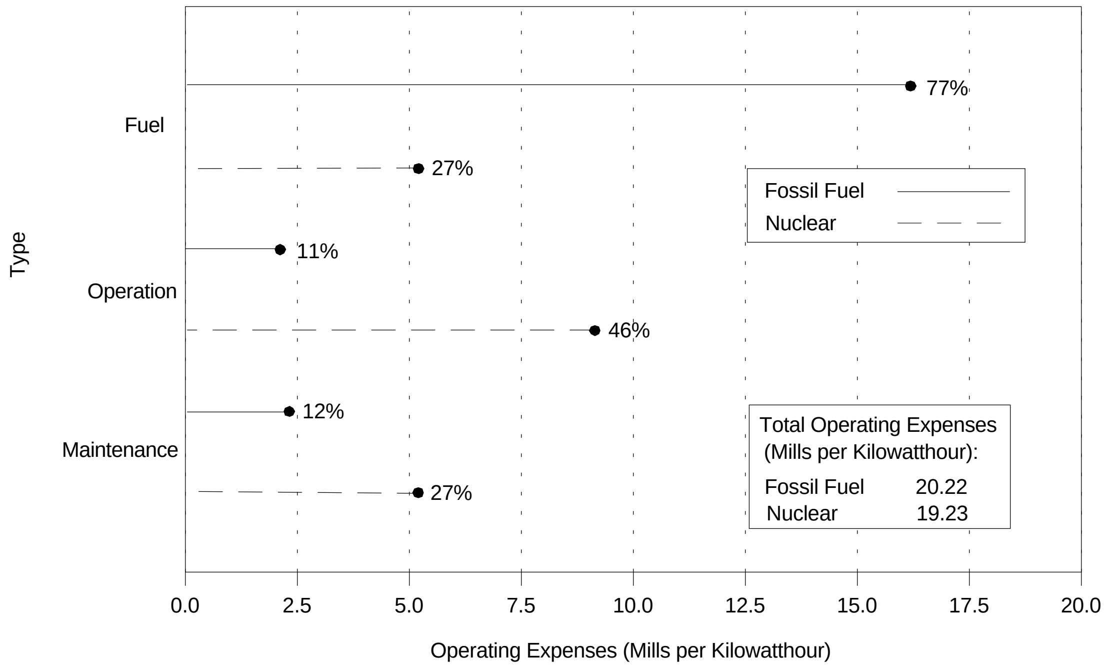
Plant Type	1995	1996	1997	1998[1]	1999
			Operation		
Nuclear	9.43	9.47	11.02	9.98	8.93
Fossil Steam	2.38	2.25	2.22	2.17	2.21
Hydroelectric[2]	3.69	3.87	3.29	3.85	4.17
Gas Turbine and Small Scale[3]	3.57	5.08	4.43	3.85	5.16
			Maintenance		
Nuclear	5.21	5.68	6.90	5.79	5.13
Fossil Steam	2.65	2.49	2.43	2.41	2.38
Hydroelectric[2]	2.19	2.08	2.49	2.00	2.60
Gas Turbine and Small Scale[3]	4.28	4.98	3.43	3.43	4.80
			Fuel		
Nuclear	5.75	5.50	5.42	5.39	5.17
Fossil Steam	16.07	16.51	16.80	15.94	15.62
Hydroelectric[2]	—	—	—	—	—
Gas Turbine and Small Scale[3]	20.83	30.58	24.94	23.02	28.72
			Total[4]		
Nuclear	20.39	20.65	23.33	21.16	19.23
Fossil Steam	21.11	21.25	21.45	20.52	20.22
Hydroelectric[2]	5.89	5.95	5.78	5.86	6.77
Gas Turbine and Small Scale[3]	28.67	40.64	32.80	30.30	38.68

1 Data for 1998 have been revised by Navigant Consulting, Inc.
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 for 1995 through 1998 are final; whereas data for 1999 are preliminary. •Expenses are average expenses weighted by net generation. •A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).

Source: Federal Energy Regulatory Commission, FERC Form 1, ''Annual Report of Major Electric Utilities, Licensees and Others.'' The 1997 through 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Figure 8. Average Operating Expenses of Fossil-Fueled and Nuclear Steam-Electric Plants for Major U.S. Investor-Owned Electric Utilities, 1999



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

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." The 1999 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

Table 14. Composite Statement of Income for Major U.S. Publicly Owned Generator Electric Utilities, 1995 Through 1999

(Thousand Dollars)

Description	1995	1996	1997	1998	1999
Operating Revenue - Electric	**23,472,888**	**24,207,226**	**25,397,219**	**26,154,732**	**26,766,900**
Operating Expenses - Electric	**18,958,876**	**19,083,980**	**20,425,111**	**20,880,194**	**21,273,860**
Operation Excluding Fuel	**11,167,114**	**11,270,829**	**11,819,689**	**11,949,846**	**11,992,638**
Fuel	2,485,770	2,497,215	3,097,486	3,169,838	3,393,281
Maintenance	1,575,208	1,637,828	1,608,781	1,631,484	1,686,120
Depreciation and Amortization	2,933,594	3,015,664	3,239,454	3,458,805	3,504,605
Taxes and Tax Equivalents	797,189	662,443	659,702	670,221	697,215
Operating Income - Electric	**4,514,013**	**5,123,246**	**4,972,108**	**5,274,538**	**5,493,040**
Other Income and Deductions	**1,174,316**	**1,237,173**	**1,351,939**	**1,352,927**	**937,809**
Income from Electric Plant Leased to Others	16,365	25,914	17,953	17,528	11,341
Allowance for Funds Used During Construction	9,145	6,660	4,320	5,208	5,802
Other Income Net	1,371,621	1,440,435	1,478,106	1,506,383	1,358,155
Less Other Electric Deductions	222,815	235,836	148,440	176,192	437,489
Total Income Before Interest Charges	**5,688,329**	**6,360,419**	**6,324,047**	**6,627,465**	**6,430,849**
Net Interest Charges	**4,728,063**	**4,634,548**	**4,681,830**	**4,574,910**	**4,467,834**
Interest Expenses	4,206,294	4,155,829	4,119,946	3,984,982	3,810,418
Other Income Deductions	521,769	478,719	561,883	589,928	657,416
Net Income Before Extraordinary Charges	**960,266**	**1,725,871**	**1,642,217**	**2,052,555**	**1,963,015**
Less **Extraordinary Items**	**–250,918**	**–2,304**	**13,258**	**120,722**	**186,344**
Net Income	**1,211,184**	**1,723,567**	**1,628,959**	**1,931,833**	**1,776,671**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 226 for 1999, 228 for 1998, 245 for 1997, 231 for 1996, and 226 for 1995.

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, 1995 Through 1999

(Thousand Dollars)

Description	1995	1996	1997	1998	1999
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**63,412,608**	**64,159,411**	**63,939,798**	**62,854,031**	**63,156,349**
Electric Utility Plant Inc Nuclear Fuel	93,771,319	97,433,005	100,346,538	101,775,589	105,804,369
Accumulated Provision for Depreciation and Amortization	30,358,711	33,273,595	36,406,740	38,921,558	42,648,020
Other Property and Investments	**20,996,914**	**19,674,912**	**20,156,959**	**19,969,531**	**21,456,288**
Current and Accrued Assets	**15,086,442**	**16,521,745**	**17,148,023**	**17,245,072**	**17,963,595**
Deferred Debits	**14,242,677**	**13,520,724**	**13,619,929**	**13,381,374**	**13,691,266**
Total Assets and Other Debits	**113,738,640**	**113,876,791**	**114,864,710**	**113,450,008**	**116,267,499**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**25,447,162**	**27,472,346**	**29,111,977**	**30,001,524**	**31,865,580**
Long-Term Debt	**74,982,156**	**73,950,415**	**73,035,157**	**70,145,214**	**69,554,404**
Other Noncurrent Liabilities	**714,354**	**766,093**	**593,007**	**608,049**	**618,451**
Current and Accrued Liabilities	**9,084,862**	**8,167,668**	**8,554,223**	**8,714,034**	**9,012,772**
Deferred Credits	**3,510,106**	**3,520,270**	**3,570,346**	**3,981,187**	**5,216,292**
Total Liabilities and Other Credits	**113,738,640**	**113,876,791**	**114,864,710**	**113,450,008**	**116,267,499**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 226 for 1999, 228 for 1998, 245 for 1997, 231 for 1996, and 226 for 1995.

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, 1995 Through 1999

Description	1995	1996	1997	1998	1999
Electric Utility Plant per Dollar of Revenue	4.0	4.0	4.0	3.9	4.0
Current Assets to Current Liabilities	1.7	2.0	2.0	2.0	2.0
Electric Utility Plant as a Percent of Total Assets	82.4	85.6	87.4	89.7	91.0
Net Electric Utility Plant as a Percent of Total Assets	55.8	56.3	55.7	55.4	54.3
Debt as a Percent of Total Liabilities	73.9	72.1	71.0	69.5	67.6
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	32.4	34.2	36.3	38.2	40.3
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	64.9	63.6	65.1	64.0	63.8
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	11.9	11.9	12.1	12.4	12.1
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	3.4	2.7	2.6	2.6	2.6
Interest Expenses as a Percent of Electric Operating Revenues	17.9	17.2	16.2	15.2	14.2
Net Income as a Percent of Electric Operating Revenues	5.2	7.1	6.4	7.4	6.6
Purchase Power Cents Per Kilowatthour	3.6	3.8	3.2	3.2	3.2
Generated Cents Per Kilowatthour	1.8	1.5	1.7	1.7	1.7
Total Power Supply Per Kilowatthour Sold	2.5	2.4	2.4	2.4	2.3

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 226 for 1999, 228 for 1998, 245 for 1997, 231 for 1996, and 226 for 1995.

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, 1995 Through 1999
(Thousand Dollars)

Description	1995	1996	1997	1998	1999
Operating Revenue - Electric	**23,472,888**	**24,207,226**	**25,397,219**	**26,154,732**	**26,766,900**
Operating Expenses - Electric	**18,958,876**	**19,083,980**	**20,425,111**	**20,880,194**	**21,273,860**
Operation Including Fuel	13,652,884	13,768,044	14,917,174	15,119,684	15,385,920
Production	10,384,858	11,080,348	11,481,328	11,608,407	11,922,977
Transmission	628,098	344,371	725,471	772,598	732,289
Distribution	425,831	497,019	538,320	603,199	515,985
Customer Accounts	323,122	365,277	390,231	390,430	414,545
Customer Service	102,061	103,390	133,257	126,813	160,158
Sales	19,617	17,528	46,181	50,804	49,112
Administrative and General	1,769,298	1,360,111	1,602,386	1,567,434	1,590,854
Maintenance	1,575,208	1,637,828	1,608,781	1,631,484	1,686,120
Depreciation and Amortization	2,933,594	3,015,664	3,080,165	3,240,505	3,241,178
Taxes and Tax Equivalents	797,189	662,443	659,702	670,221	697,215
Income from Electric Utility Operations	**4,514,013**	**5,123,246**	**4,972,108**	**5,274,538**	**5,493,040**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 226 for 1999, 228 for 1998, 245 for 1997, 231 for 1996, and 226 for 1995.

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, 1995 Through 1999
(Thousand Dollars)

Description	1995	1996	1997	1998	1999
Operating Revenue - Electric	**8,435,445**	**8,581,642**	**8,585,879**	**8,790,223**	**9,354,023**
Operating Expenses - Electric	**7,978,811**	**8,122,815**	**8,033,488**	**8,245,380**	**8,737,044**
Operation Excluding Fuel	**7,172,612**	**7,358,592**	**7,117,155**	**7,437,112**	**7,873,718**
Fuel	247	—	—	–540	–141
Maintenance	249,580	244,115	337,769	263,356	272,299
Depreciation and Amortization	312,724	313,720	353,948	330,433	368,552
Taxes and Tax Equivalents	243,648	206,389	224,617	215,019	222,615
Operating Income - Electric	**456,634**	**458,827**	**552,391**	**544,843**	**616,979**
Other Income and Deductions	**142,214**	**153,864**	**102,307**	**130,282**	**137,738**
Income from Electric Plant Leased to Others	4,345	12,569	12,989	4,248	4,465
Allowance for Funds Used During Construction	41	70	311	192	197
Other Income Net	215,559	207,859	165,655	185,272	205,362
Less Other Electric Deductions	77,731	66,634	76,649	59,430	72,285
Total Income Before Interest Charges	**598,847**	**612,691**	**654,698**	**675,126**	**754,717**
Net Interest Charges	**168,632**	**148,146**	**148,297**	**152,428**	**155,798**
Interest Expenses	127,013	99,768	107,351	102,729	107,842
Other Income Deductions	41,619	48,378	40,947	49,699	47,956
Net Income Before Extraordinary Charges	**430,215**	**464,545**	**506,400**	**522,698**	**598,919**
Less **Extraordinary Items**	**6,659**	**4,066**	**–3,050**	**–9,842**	**–7,038**
Net Income	**423,556**	**460,479**	**509,451**	**532,539**	**605,956**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 267 for 1999, 259 for 1998, 299 for 1997, 284 for 1996, and 286 for 1995.

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, 1995 Through 1999
(Thousand Dollars)

Description	1995	1996	1997	1998	1999
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**6,272,158**	**6,259,916**	**8,447,445**	**6,871,025**	**7,437,385**
Electric Utility Plant Inc Nuclear Fuel	9,936,064	9,925,097	12,831,306	10,963,297	11,952,629
Accumulated Provision for Depreciation and Amortization	3,663,906	3,665,181	4,383,861	4,092,272	4,515,244
Other Property and Investments	**2,196,898**	**1,885,263**	**2,067,375**	**2,123,546**	**2,328,518**
Current and Accrued Assets	**2,884,088**	**2,701,644**	**2,925,365**	**2,857,991**	**3,180,710**
Deferred Debits	**492,691**	**407,965**	**465,338**	**358,010**	**313,893**
Total Assets and Other Debits	**11,841,016**	**11,254,787**	**13,905,523**	**12,210,573**	**13,260,506**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**6,938,969**	**7,150,022**	**8,543,320**	**7,871,482**	**8,808,622**
Long-Term Debt	**3,441,757**	**2,593,375**	**3,808,733**	**2,676,839**	**2,716,531**
Other Noncurrent Liabilities	**16,179**	**17,991**	**14,808**	**137,989**	**128,768**
Current and Accrued Liabilities	**1,232,623**	**1,263,814**	**1,259,125**	**1,317,256**	**1,407,290**
Deferred Credits	**211,487**	**229,585**	**279,537**	**207,007**	**199,295**
Total Liabilities and Other Credits	**11,841,016**	**11,254,787**	**13,905,523**	**12,210,573**	**13,260,506**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 267 for 1999, 259 for 1998, 299 for 1997, 284 for 1996, and 286 for 1995.

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, 1995 Through 1999

Description	1995	1996	1997	1998	1999
Electric Utility Plant per Dollar of Revenue	1.2	1.2	1.5	1.2	1.3
Current Assets to Current Liabilities	2.3	2.1	2.3	2.2	2.3
Electric Utility Plant as a Percent of Total Assets	83.9	88.2	92.3	89.8	90.1
Net Electric Utility Plant as a Percent of Total Assets	52.9	55.6	60.7	56.3	56.1
Debt as a Percent of Total Liabilities	39.5	34.3	36.4	32.7	31.1
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	36.9	36.9	34.2	37.3	37.8
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	88.0	88.6	86.8	87.6	87.1
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	3.7	3.6	4.1	3.7	3.9
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.9	2.4	2.6	2.4	2.4
Interest Expenses as a Percent of Electric Operating Revenues	1.5	1.2	1.3	1.2	1.2
Net Income as a Percent of Electric Operating Revenues	5.0	5.4	5.9	6.1	6.5
Purchase Power Cents Per Kilowatthour	4.3	4.0	4.0	4.1	4.1

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 267 for 1999, 259 for 1998, 299 for 1997, 284 for 1996, and 286 for 1995.

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, 1995 Through 1999

(Thousand Dollars)

Description	1995	1996	1997	1998	1999
Operating Revenue - Electric	**8,435,445**	**8,581,642**	**8,585,879**	**8,790,223**	**9,354,023**
Operating Expenses - Electric	**7,978,811**	**8,122,816**	**8,033,488**	**8,245,380**	**8,737,044**
Operation Including Fuel	7,172,858	7,358,592	7,117,155	7,436,572	7,873,577
Production	6,421,965	6,578,344	6,239,721	6,660,705	7,015,036
Transmission	35,184	50,812	56,969	44,443	47,501
Distribution	204,130	233,630	303,983	229,609	261,223
Customer Accounts	125,143	141,458	139,156	129,856	142,717
Customer Service	17,934	18,229	16,379	20,862	22,182
Sales	9,535	11,616	12,897	8,868	13,785
Administrative and General	358,367	324,503	348,051	342,228	371,133
Maintenance	249,580	244,115	337,769	263,356	272,299
Depreciation and Amortization	312,724	313,720	350,862	326,863	364,603
Taxes and Tax Equivalents	243,648	206,389	224,617	215,019	222,615
Income from Electric Utility Operations	**456,634**	**458,826**	**552,391**	**544,843**	**616,979**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1995-1997 data represent those utilities meeting a threshold of 120 million kilowatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 267 for 1999, 259 for 1998, 299 for 1997, 284 for 1996, and 286 for 1995.

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

U.S. Electric Utility Environmental Statistics

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

Background

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

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

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

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

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

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

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

Emission Standards

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

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

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

Emission Reductions

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

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

Environmental Equipment

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

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

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

Data Sources

Estimates are provided in the following tables for SO_2, NO_x, and CO_2 emissions from fossil-fueled steam-electric generating units. The methodology for computing emission estimates is described in Appendix A. Emissions of SO_2 and NO_x have been revised from the updated Air Pollutant Emissions Factors (AP-42 5th edition, through supplement E) of the Environment Protection Agency on July 1999. Emissions of CO_2 have been revised from the *Emissions of Greenhouse Gases in the United States 1998*, November 1999. Additional detailed information on emissions from electric utilities can be obtained in Chapter 6 of the *Annual Energy Outlook*.[9] Also presented in the following tables are the number and capacity of fossil-fueled steam-electric generators with environmental equipment (scrubbers, particulate collectors, and cooling towers). Because power plants can have more than one type of environmental equipment, the generators at these plants can be included in more than one category. Also, not all utility plants have environmental equipment. Data regarding the quality of fossil fuels used to produce electricity by electric utilities, including heat, sulfur, and ash content, are also provided in the following tables. Lastly, average flue gas desulfurization costs (that is, operation and maintenance costs per kilowatthour of generation and installation costs per kilowatt of nameplate capacity) are presented.

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

[9] Energy Information Administration, *Annual Energy Outlook 2000* DOE/EIA-0383(00)(Washington, DC, 1999).

Table 22. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities, 1995 Through 1999
(Thousand Short Tons)

Emission[1]	1995	1996	1997	1998	1999
Sulfur Dioxide (SO2)	11,437	12,053	12,317	12,413	11,968
Nitrogen Oxides (NOx)	6,737	6,996	7,227	7,221	7,051
Carbon Dioxide (CO2)	1,995,471	2,065,339	2,142,118	2,209,281	2,191,576

[1] In 1995, the useful utility thermal output produced additional emissions of 141 thousand short tons of sulfur dioxide, 44 thousand short tons of nitrogen oxides, and 11,378 thousand short tons of carbon dioxide. In 1996, the useful utility thermal output produced additional emissions of 172 thousand short tons of sulfur dioxide, 58 thousand short tons of nitrogen oxides, and 15,837 thousand short tons of carbon dioxide. In 1997, the useful utility thermal output produced additional emissions of 192 thousand short tons of sulfur dioxide, 66 thousand short tons of nitrogen oxides, and 18,159 thousand short tons of carbon dioxide. In 1998, the useful utility thermal output produced additional emissions of 197 thousand short tons of sulfur dioxide, 62 thousand short tons of nitrogen oxides, and 17,180 thousand short tons of carbon dioxide. In 1999, the useful utility thermal output produced additional emissions of 186 thousand short tons of sulfur dioxide, 65 thousand short tons of nitrogen oxides, and 18,913 thousand short tons of carbon dioxide.

Notes: •Data for 1999 are final pending approval by the Environmental Protection Agency. Data for prior years are final. •Emissions of NOx, and SO2 have been revised from the updated (July 1999) Air Pollutant Emissions Factors (AP-42, 5th edition, Supplement E) of the Environmental Protection Agency; emissions of CO2 have been revised from ''Emissions of Greenhouse Gases in the United States 1998,'' November 1999 (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data. Historical data have been revised to reflect additional data reported by respondents and additional emissions data from plants 10 megawatts or less.

Sources: Energy Information Administration, Form EIA-767, ''Steam-Electric Plant Operation and Design Report,'' Form EIA-759, ''Monthly Power Plant Report.''

Table 23. Number and Capacity of Fossil-Fueled Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment, 1995 Through 1999

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1995	178	84,677	1,134	351,198
1996	182	86,359	1,136	352,254
1997	183	86,605	1,136	352,254
1998	186	87,783	1,130	351,790
1999	192	89,666	1,148	353,480

Environmental Equipment	Cooling Towers		Total[2]	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1995	471	165,295	1,295	375,691
1996	477	166,749	1,301	377,244
1997	480	166,886	1,304	377,381
1998	474	166,896	1,294	377,117
1999	505	175,520	1,343	387,192

[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 1999 are final pending approval by the Environmental Protection Agency. Data for prior years are final. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. •Historical data have been revised to reflect additional data reported by respondents.

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

Table 24. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Census Division and State, 1998 and 1999

(Thousand Short Tons)

Census Division State	1998			1999		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide
New England	**209**	**60**	**35,692**	**189**	**57**	**33,208**
Connecticut	48	12	10,143	23	6	5,370
Maine	12	2	1,550	5	1	849
Massachusetts	98	33	18,307	113	41	22,100
New Hampshire	51	12	4,935	48	9	4,837
Rhode Island	*	2	697	0	0	9
Vermont	0	0	60	0	0	43
Middle Atlantic	**1,408**	**424**	**172,088**	**1,075**	**312**	**135,916**
New Jersey	44	28	8,525	48	30	9,353
New York	268	103	49,776	161	55	33,813
Pennsylvania	1,096	293	113,788	866	226	92,749
East North Central	**3,433**	**1,795**	**451,923**	**3,250**	**1,739**	**450,870**
Illinois	695	329	80,024	616	338	80,470
Indiana	803	473	119,709	811	465	122,711
Michigan	411	286	76,098	401	281	75,691
Ohio	1,315	522	130,543	1,225	468	126,691
Wisconsin	209	186	45,549	197	186	45,307
West North Central	**813**	**906**	**234,967**	**798**	**923**	**234,488**
Iowa	147	151	36,402	144	152	36,558
Kansas	98	129	34,014	89	137	36,395
Minnesota	83	133	34,856	85	125	33,056
Missouri	265	268	70,749	248	284	69,379
Nebraska	56	95	21,176	58	91	20,431
North Dakota	144	112	34,149	152	115	34,464
South Dakota	20	17	3,621	23	19	4,206
South Atlantic	**3,250**	**1,332**	**459,508**	**3,579**	**1,285**	**462,447**
Delaware	35	15	5,920	27	12	5,319
District of Columbia	1	0	267	1	0	259
Florida	710	334	119,453	645	319	114,481
Georgia	483	205	75,283	482	210	77,302
Maryland	265	93	33,066	306	88	33,766
North Carolina	448	199	68,411	429	178	68,006
South Carolina	250	90	33,079	248	94	35,894
Virginia	204	100	35,088	214	94	36,181
West Virginia	853	296	88,941	1,227	289	91,240
East South Central	**1,796**	**813**	**240,386**	**1,775**	**826**	**250,872**
Alabama	511	243	75,079	480	254	77,361
Kentucky	739	314	87,135	796	336	95,613
Mississippi	128	69	22,472	109	70	22,381
Tennessee	419	186	55,700	390	166	55,518
West South Central	**908**	**966**	**337,135**	**806**	**978**	**340,426**
Arkansas	74	89	28,162	71	94	30,121
Louisiana	179	126	41,946	128	128	43,414
Oklahoma	89	149	45,535	91	149	45,070
Texas	566	602	221,492	516	607	221,821
Mountain	**503**	**818**	**235,313**	**387**	**808**	**236,005**
Arizona	96	133	41,070	64	131	43,112
Colorado	94	132	36,495	86	134	36,919
Idaho	0	0	*	0	0	*
Montana	18	60	18,835	17	60	18,706
Nevada	54	74	23,146	50	72	22,908
New Mexico	120	127	32,246	56	126	32,121
Utah	30	102	34,447	28	102	34,671
Wyoming	91	190	49,074	85	183	47,567
Pacific Contiguous	**75**	**94**	**33,943**	**87**	**93**	**36,244**
California	0	27	17,703	0	29	21,007
Oregon	11	19	5,354	14	20	5,389
Washington	64	48	10,885	73	44	9,847
Pacific Noncontiguous	**18**	**15**	**8,325**	**22**	**32**	**11,100**
Alaska	0	6	2,654	5	23	5,254
Hawaii	18	8	5,671	17	9	5,847
U.S. Total	**12,413**	**7,221**	**2,209,281**	**11,968**	**7,051**	**2,191,576**

* =Value less than 0.5.

Notes: •Data for 1999 are final pending approval by the Environmental Protection Agency. Data for 1998 are final. •Emissions of NOx, and SO2 have been revised from the updated (July 1999) Air Pollutant Emissions Factors (AP-42, 5th edition, Supplement E) of the Environmental Protection Agency; emissions of CO2 have been revised from ''Emissions of Greenhouse Gases in the United States 1998,'' November 1999 (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

Sources: Energy Information Administration, Form EIA-767, ''Steam-Electric Plant Operation and Design Report,'' Form EIA-759, ''Monthly Power Plant Report.''

Table 25. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Fossil Fuel, Census Division, and State, 1999
(Thousand Short Tons)

Census Division State	Coal			Petroleum			Gas			Other[1]		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide
New England	**93**	**35**	**14,277**	**96**	**17**	*****	*****	**5**	**2,559**	*****	**0**	**0**
Connecticut	0	0	0	23	4	*	*	1	816	*	0	0
Maine	0	0	0	5	1	849	0	0	0	0	0	0
Massachusetts	58	28	10,889	55	10	*	*	3	1,698	*	0	0
New Hampshire	34	8	3,388	14	1	*	0	*	30	*	0	0
Rhode Island	0	0	0	0	*	9	0	0	0	0	0	0
Vermont	0	0	0	0	*	29	0	*	14	*	0	0
Middle Atlantic	**991**	**273**	**107,414**	**83**	**16**	**14,498**	*****	**22**	**14,004**	*****	**0**	**0**
New Jersey	46	25	6,838	2	1	604	*	4	1,911	*	0	0
New York	106	28	12,113	55	11	10,409	*	16	11,292	0	0	0
Pennsylvania	839	220	88,463	27	5	3,485	*	2	802	*	0	0
East North Central	**3,222**	**1,715**	**440,081**	**28**	**5**	**3,126**	*****	**16**	**7,664**	*****	**3**	**0**
Illinois	601	331	76,572	16	2	736	*	5	3,162	0	0	0
Indiana	810	463	121,797	*	*	295	*	2	619	0	0	0
Michigan	395	274	71,887	6	2	1,372	*	6	2,432	*	0	0
Ohio	1,225	466	125,618	*	*	442	*	1	630	0	0	0
Wisconsin	192	181	44,206	5	1	281	*	2	821	*	3	0
West North Central	**782**	**908**	**227,766**	**16**	**2**	**1,352**	*****	**10**	**4,529**	**1**	**2**	**841**
Iowa	139	150	35,839	5	1	285	*	1	340	*	*	94
Kansas	87	132	33,935	2	*	325	*	5	2,135	0	0	0
Minnesota	84	122	31,829	*	*	91	*	1	393	1	2	743
Missouri	239	280	67,686	9	1	554	*	3	1,135	*	*	5
Nebraska	58	90	20,128	*	*	33	*	1	270	0	0	0
North Dakota	152	115	34,429	*	*	35	0	0	0	0	0	0
South Dakota	23	19	3,921	*	*	29	*	1	256	0	0	0
South Atlantic	**3,241**	**1,171**	**396,028**	**338**	**62**	**41,895**	*****	**53**	**24,503**	*****	*****	**22**
Delaware	23	9	3,155	4	1	1,059	*	2	1,105	0	0	0
District of Columbia	0	0	0	1	*	259	0	0	0	0	0	0
Florida	356	228	63,129	289	50	32,603	*	41	18,727	*	*	22
Georgia	479	207	75,373	3	1	684	*	2	1,244	0	0	0
Maryland	284	80	28,824	22	5	3,838	*	2	1,104	0	0	0
North Carolina	429	176	67,078	*	*	306	0	1	622	0	0	0
South Carolina	248	93	35,229	1	*	364	0	1	301	0	0	0
Virginia	197	88	32,170	17	3	2,633	0	3	1,378	0	0	0
West Virginia	1,226	289	91,070	*	*	148	*	*	22	0	0	0
East South Central	**1,732**	**803**	**238,468**	**43**	**6**	**4,598**	*****	**17**	**7,806**	**0**	**0**	**0**
Alabama	476	250	75,380	4	1	762	*	3	1,219	0	0	0
Kentucky	796	335	94,450	*	*	818	0	1	345	0	0	0
Mississippi	70	53	13,782	38	5	2,561	*	13	6,039	0	0	0
Tennessee	390	165	54,857	*	*	458	0	*	203	0	0	0
West South Central	**756**	**780**	**234,809**	**50**	**5**	**3,056**	*****	**194**	**102,561**	**0**	**0**	**0**
Arkansas	68	89	27,174	3	1	377	*	5	2,569	0	0	0
Louisiana	81	89	22,394	47	4	2,526	*	35	18,494	0	0	0
Oklahoma	91	124	33,481	*	*	9	*	25	11,580	0	0	0
Texas	515	478	151,760	*	*	144	*	129	69,917	0	0	0
Mountain	**386**	**785**	**225,290**	*****	*****	**192**	**1**	**23**	**10,522**	**0**	**0**	**0**
Arizona	64	125	40,072	*	*	42	*	6	2,999	0	0	0
Colorado	86	131	35,748	*	*	29	1	3	1,142	0	0	0
Idaho	0	0	0	0	0	*	0	0	0	0	0	0
Montana	17	60	18,680	*	*	7	*	*	20	0	0	0
Nevada	50	63	19,041	*	*	23	*	9	3,844	0	0	0
New Mexico	56	122	29,972	*	*	28	*	4	2,121	0	0	0
Utah	28	101	34,261	*	*	24	*	1	386	0	0	0
Wyoming	85	183	47,518	*	*	39	0	*	10	0	0	0
Pacific Contiguous	**87**	**59**	**13,461**	*****	*****	**66**	*****	**33**	**22,716**	**0**	**0**	**0**
California	0	0	0	*	*	51	*	29	20,957	0	0	0
Oregon	14	16	4,016	*	*	6	0	3	1,367	0	0	0
Washington	73	43	9,445	*	*	9	0	1	393	0	0	0
Pacific Noncontiguous	**5**	**18**	**2,710**	**17**	**10**	**6,599**	**0**	**4**	**1,792**	**0**	**0**	**0**
Alaska	5	18	2,710	*	1	752	0	4	1,792	0	0	0
Hawaii	0	0	0	17	9	5,847	0	0	0	0	0	0
U.S. Total	**11,295**	**6,547**	**1,900,304**	**670**	**123**	**91,753**	**2**	**376**	**198,655**	**1**	**5**	**863**

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

Notes: •Data for 1999 are final pending approval by the Environmental Protection Agency. •Emissions of NOx, and SO2 have been revised from the updated (July 1999) Air Pollutant Emissions Factors (AP-42, 5th edition, Supplement E) of the Environmental Protection Agency; emissions of CO2 have been revised from ''Emissions of Greenhouse Gases in the United States 1998,'' November 1999 (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data. •*=Value less than 0.5.

Sources: Energy Information Administration, Form EIA-767, ''Steam-Electric Plant Operation and Design Report,'' Form EIA-759, ''Monthly Power Plant 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, 1999

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**	**2,613**	**0**	**0**	**15**	**2,613**	**0**	**0**
Connecticut	1	239	0	0	1	239	0	0
Maine	0	0	0	0	0	0	0	0
Massachusetts	9	1,764	0	0	9	1,764	0	0
New Hampshire	5	609	0	0	5	609	0	0
Rhode Island	0	0	0	0	0	0	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	**89**	**26,839**	**16**	**7,112**	**87**	**24,992**	**18**	**13,213**
New Jersey	6	1,685	1	163	6	1,685	0	0
New York	27	4,296	2	810	27	4,296	0	0
Pennsylvania	56	20,858	13	6,139	54	19,011	18	13,213
East North Central	**301**	**82,646**	**26**	**12,043**	**298**	**81,743**	**44**	**21,393**
Illinois	55	17,123	3	821	55	17,123	2	562
Indiana	70	21,217	14	5,964	68	21,125	25	9,487
Michigan	52	13,206	0	0	51	12,394	3	1,010
Ohio	85	24,047	7	5,097	85	24,047	11	8,854
Wisconsin	39	7,053	2	160	39	7,053	3	1,479
West North Central	**140**	**38,203**	**24**	**10,890**	**134**	**35,731**	**44**	**14,341**
Iowa	31	6,307	1	176	30	5,709	7	2,278
Kansas	19	5,604	7	3,920	17	5,547	10	3,315
Minnesota	25	7,054	8	3,333	22	5,236	12	5,604
Missouri	38	11,448	2	455	38	11,448	7	789
Nebraska	14	3,127	0	0	14	3,127	4	430
North Dakota	12	4,207	6	3,007	12	4,207	4	1,925
South Dakota	1	456	0	0	1	456	0	0
South Atlantic	**218**	**71,817**	**24**	**12,393**	**218**	**71,817**	**67**	**37,666**
Delaware	7	997	0	0	7	997	2	461
District of Columbia	0	0	0	0	0	0	0	0
Florida	29	12,205	9	4,971	29	12,205	12	6,757
Georgia	37	14,491	1	123	37	14,491	12	9,774
Maryland	15	4,943	0	0	15	4,943	2	1,370
North Carolina	45	12,494	0	0	45	12,494	6	3,126
South Carolina	26	6,333	6	2,509	26	6,333	15	4,795
Virginia	26	5,397	2	848	26	5,397	5	1,561
West Virginia	33	14,958	6	3,942	33	14,958	13	9,822
East South Central	**138**	**42,517**	**29**	**12,307**	**135**	**40,578**	**30**	**14,669**
Alabama	41	14,362	4	1,597	39	12,586	6	4,376
Kentucky	54	15,985	21	7,710	53	15,822	21	9,394
Mississippi	6	2,150	2	400	6	2,150	3	900
Tennessee	37	10,020	2	2,600	37	10,020	0	0
West South Central	**59**	**33,703**	**16**	**10,562**	**59**	**33,703**	**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	20,737	14	9,321	36	20,737	14	7,109
Mountain	**88**	**30,712**	**57**	**24,360**	**88**	**30,712**	**75**	**26,165**
Arizona	14	5,749	12	5,287	14	5,749	12	5,347
Colorado	26	4,984	9	2,648	26	4,984	23	4,480
Idaho	0	0	0	0	0	0	0	0
Montana	5	2,518	4	2,327	5	2,518	4	2,327
Nevada	8	2,769	5	879	8	2,769	7	1,951
New Mexico	10	4,375	10	4,375	10	4,375	5	2,105
Utah	10	4,461	7	3,826	10	4,461	10	4,461
Wyoming	15	5,856	10	5,018	15	5,856	14	5,494
Pacific Contiguous	**8**	**2,328**	**0**	**0**	**5**	**2,220**	**6**	**1,668**
California	5	308	0	0	2	200	4	208
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	**1,056**	**331,379**	**192**	**89,666**	**1,039**	**324,109**	**316**	**146,377**

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

Notes: •Data for 1999 are final pending final approval by the Environmental Protection Agency. •Totals may not equal sum of components because of independent rounding. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts.

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

Table 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, 1999

Census Division State	Generating Units[1]		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**28**	**6,270**	**26**	**5,760**	**2**	**510**
Connecticut	11	1,866	10	1,452	1	415
Maine	7	953	7	953	0	0
Massachusetts	9	3,037	8	2,942	1	95
New Hampshire	1	414	1	414	0	0
Rhode Island	0	0	0	0	0	0
Vermont	0	0	0	0	0	0
Middle Atlantic	**34**	**10,362**	**32**	**8,661**	**3**	**1,877**
New Jersey	7	952	7	952	1	176
New York	16	6,060	16	6,060	0	0
Pennsylvania	11	3,351	9	1,650	2	1,701
East North Central	**9**	**2,170**	**5**	**625**	**4**	**1,544**
Illinois	1	210	0	0	1	210
Indiana	0	0	0	0	0	0
Michigan	6	1,743	4	512	2	1,231
Ohio	2	217	1	114	1	104
Wisconsin	0	0	0	0	0	0
West North Central	**16**	**1,549**	**3**	**181**	**13**	**1,367**
Iowa	1	19	1	19	0	0
Kansas	10	1,307	0	0	10	1,307
Minnesota	2	163	2	163	0	0
Missouri	3	61	0	0	3	61
Nebraska	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0
South Atlantic	**46**	**14,406**	**33**	**11,157**	**16**	**4,406**
Delaware	3	635	3	635	1	114
District of Columbia	2	580	0	0	2	580
Florida	30	9,112	21	7,761	9	1,351
Georgia	1	46	1	46	0	0
Maryland	6	2,131	4	813	3	1,480
North Carolina	0	0	0	0	0	0
South Carolina	0	0	0	0	0	0
Virginia	4	1,902	4	1,902	1	882
West Virginia	0	0	0	0	0	0
East South Central	**4**	**666**	**1**	**460**	**3**	**206**
Alabama	1	460	1	460	0	0
Kentucky	0	0	0	0	0	0
Mississippi	3	206	0	0	3	206
Tennessee	0	0	0	0	0	0
West South Central	**94**	**14,484**	**4**	**2,258**	**92**	**13,325**
Arkansas	6	546	0	0	6	546
Louisiana	14	2,433	2	1,184	13	1,841
Oklahoma	19	4,350	1	567	18	3,783
Texas	55	7,155	1	507	55	7,155
Mountain	**35**	**3,233**	**2**	**101**	**35**	**3,233**
Arizona	16	1,501	0	0	16	1,501
Colorado	3	437	2	101	3	437
Idaho	0	0	0	0	0	0
Montana	0	0	0	0	0	0
Nevada	4	243	0	0	4	243
New Mexico	9	800	0	0	9	800
Utah	3	252	0	0	3	252
Wyoming	0	0	0	0	0	0
Pacific Contiguous	**21**	**2,673**	**3**	**167**	**21**	**2,673**
California	21	2,673	3	167	21	2,673
Oregon	0	0	0	0	0	0
Washington	0	0	0	0	0	0
Pacific Noncontiguous	**0**	**0**	**0**	**0**	**0**	**0**
Alaska	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	**287**	**55,812**	**109**	**29,371**	**189**	**29,142**

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

Notes: •Data for 1999 are final pending final approval by the Environmental Protection Agency. •Totals may not equal sum of components because of independent rounding. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts.

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

Table 28. Average Quality of Fossil Fuels Burned at U.S. Electric Utilities by Census Division and State, 1998 and 1999

Census Division State	Coal						Petroleum				Gas	
	1998			1999			1998		1999		1998	1999
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Cubic Foot	
New England	**12,627**	**0.86**	**8.1**	**12,656**	**0.88**	**7.9**	**150,910**	**1.06**	**151,119**	**0.99**	**1,030**	**1,030**
Connecticut	13,123	.53	6.8	—	—	—	151,221	.88	151,540	.87	1,034	1,028
Maine	—	—	—	—	—	—	151,063	1.28	150,653	1.03	—	—
Massachusetts	12,453	.71	8.6	12,527	.72	8.1	150,695	1.09	151,055	.96	1,029	1,032
New Hampshire	12,939	1.41	6.9	13,077	1.39	7.1	150,919	1.64	150,751	1.58	1,019	1,011
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	136,130	.07	136,000	.05	1,013	1,012
Middle Atlantic	**12,517**	**2.02**	**11.1**	**12,616**	**2.04**	**10.6**	**150,035**	**.75**	**149,848**	**.79**	**1,034**	**1,028**
New Jersey	12,862	1.22	9.2	12,862	1.24	9.5	149,192	.66	150,210	.70	1,042	1,032
New York	12,960	1.70	8.0	13,062	1.75	8.1	149,866	.76	149,803	.83	1,034	1,027
Pennsylvania	12,403	2.13	11.9	12,506	2.16	11.2	150,828	.69	149,993	.61	1,031	1,032
East North Central	**10,535**	**1.36**	**8.3**	**10,529**	**1.32**	**8.3**	**144,406**	**.61**	**144,449**	**.62**	**1,017**	**1,019**
Illinois	9,706	1.12	7.1	9,648	1.01	6.9	145,307	.48	143,121	.46	1,018	1,021
Indiana	10,468	1.65	8.1	10,571	1.65	8.4	137,143	.31	137,202	.28	1,020	1,024
Michigan	10,416	.66	6.6	10,392	.65	6.7	147,020	.83	147,970	.83	1,016	1,015
Ohio	11,851	2.04	11.5	11,900	1.99	11.5	137,796	.29	138,008	.28	1,030	1,029
Wisconsin	9,220	.50	5.6	9,075	.47	5.4	140,116	.28	139,999	.22	1,011	1,007
West North Central	**8,344**	**.49**	**6.2**	**8,310**	**.48**	**6.3**	**140,519**	**.44**	**144,187**	**.75**	**1,003**	**1,010**
Iowa	8,579	.42	5.6	8,558	.42	5.5	138,382	.42	138,522	.44	1,012	1,014
Kansas	8,682	.48	5.6	8,602	.46	5.6	138,273	.32	147,939	1.00	1,000	1,009
Minnesota	8,908	.49	6.3	8,918	.50	6.3	137,482	.17	137,792	.16	1,010	1,014
Missouri	8,906	.40	5.2	8,875	.37	5.1	141,381	.49	138,282	.34	1,010	1,009
Nebraska	8,547	.28	4.7	8,500	.29	5.0	146,135	.90	142,010	.69	999	1,005
North Dakota	6,487	.77	9.2	6,481	.77	9.4	142,908	.51	139,722	.49	—	—
South Dakota	8,681	.60	8.8	8,614	.60	8.2	139,923	.39	139,958	.39	1,003	1,021
South Atlantic	**12,257**	**1.29**	**10.0**	**12,288**	**1.28**	**9.9**	**151,141**	**1.40**	**151,379**	**1.35**	**1,016**	**1,022**
Delaware	12,778	.97	8.3	12,661	.99	8.9	149,024	.78	150,201	.68	1,044	1,035
District of Columbia	—	—	—	—	—	—	143,280	.77	143,522	.87	—	—
Florida	11,977	1.63	8.1	12,116	1.63	8.0	151,587	1.49	151,705	1.45	1,014	1,019
Georgia	11,731	.84	9.3	11,632	.81	9.2	146,199	1.93	147,423	1.55	1,024	1,025
Maryland	12,931	1.18	9.0	12,905	1.37	9.2	150,633	.96	150,808	.99	1,047	1,041
North Carolina	12,370	.88	10.4	12,415	.85	10.4	139,459	.20	139,299	.20	—	1,032
South Carolina	12,783	1.28	8.8	12,775	1.16	8.7	139,522	.13	143,047	.77	1,037	1,025
Virginia	12,559	.98	10.7	12,729	1.05	10.3	149,854	1.11	151,935	1.15	1,059	1,080
West Virginia	12,316	1.89	12.4	12,362	1.86	12.0	139,128	.34	138,933	.34	1,000	1,000
East South Central	**11,578**	**1.61**	**10.0**	**11,435**	**1.55**	**9.6**	**148,335**	**2.20**	**149,209**	**1.73**	**1,032**	**1,019**
Alabama	11,472	1.11	10.3	11,009	.98	9.4	139,116	.29	152,011	.97	1,068	1,019
Kentucky	11,707	2.12	11.0	11,679	2.10	10.8	137,855	.32	138,106	.30	1,023	1,021
Mississippi	10,580	.76	6.3	11,018	.73	6.7	149,052	2.33	148,129	2.43	1,030	1,019
Tennessee	11,755	1.66	8.7	11,739	1.62	8.6	138,105	.24	138,039	.22	—	—
West South Central	**7,760**	**.61**	**9.2**	**7,743**	**.55**	**9.3**	**150,392**	**1.19**	**148,135**	**1.01**	**1,025**	**1,022**
Arkansas	8,570	.30	4.7	8,592	.26	4.7	145,967	1.29	148,484	1.16	1,016	1,018
Louisiana	7,932	.56	7.5	8,008	.53	7.0	152,101	1.26	150,954	1.17	1,035	1,031
Oklahoma	8,637	.31	4.9	8,614	.33	5.2	138,763	.32	138,834	.32	1,030	1,030
Texas	7,435	.73	11.1	7,403	.64	11.2	139,951	.25	138,038	.15	1,022	1,019
Mountain	**9,763**	**.56**	**11.3**	**9,781**	**.55**	**11.2**	**140,519**	**.21**	**139,018**	**.23**	**1,022**	**1,020**
Arizona	10,214	.55	12.7	10,225	.53	12.7	139,153	.08	139,549	.33	1,012	1,010
Colorado	9,841	.39	6.8	9,776	.38	6.6	138,645	.10	135,178	.22	1,009	980
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	8,433	.72	9.5	8,437	.73	9.8	141,000	.50	141,000	.50	1,052	1,095
Nevada	11,903	.48	9.7	11,958	.46	9.4	148,935	.47	144,874	.40	1,042	1,043
New Mexico	9,064	.80	22.7	9,088	.80	22.9	134,722	.10	134,722	.10	1,012	1,012
Utah	11,485	.49	11.7	11,642	.47	10.3	139,123	.13	139,220	.12	1,042	1,043
Wyoming	8,757	.55	7.5	8,736	.52	7.5	139,301	.15	139,088	.17	1,044	1,045
Pacific Contiguous	**8,118**	**.53**	**10.8**	**8,229**	**.64**	**10.7**	**141,842**	**.41**	**139,915**	**.31**	**1,023**	**1,019**
California	—	—	—	—	—	—	146,226	.55	145,548	.25	1,023	1,019
Oregon	8,707	.33	5.2	9,026	.38	6.1	138,800	.50	138,800	.50	—	—
Washington	7,927	.60	12.6	7,935	.73	12.4	140,000	.05	139,900	.07	1,037	1,052
Pacific Noncontiguous	**7,596**	**.16**	**10.8**	**7,675**	**.18**	**9.8**	**149,143**	**.63**	**149,425**	**.60**	**—**	**—**
Alaska	7,596	.16	10.8	7,675	.18	9.8	133,973	.29	132,349	.29	—	—
Hawaii	—	—	—	—	—	—	149,207	.63	149,457	.61	—	—
U.S. Average	**10,218**	**1.07**	**9.2**	**10,197**	**1.03**	**9.1**	**150,419**	**1.17**	**150,528**	**1.12**	**1,025**	**1,022**

Notes: •Data for 1999 are final pending approval by the Environmental Protection Agency. Data for 1998 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, 1995 Through 1999

Census Division State	Average O&M Costs (mills per kilowatthour)					Average Installed Costs (dollars per kilowatt)				
	1995	1996	1997	1998	1999	1995	1996	1997	1998	1999
New England	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Connecticut	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—
New Hampshire	—	—	—	—	—	—	—	—	—	—
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**3.02**	**2.25**	**2.21**	**2.19**	**2.17**	**184**	**183**	**183**	**183**	**183**
New Jersey	3.36	3.66	3.24	4.85	NM	398	398	398	398	398
New York	1.18	1.33	1.35	1.19	1.02	331	331	331	331	331
Pennsylvania	3.40	2.38	2.36	2.35	2.42	158	156	156	157	157
East North Central	**1.79**	**1.84**	**3.39**	**2.68**	**3.07**	**128**	**129**	**129**	**125**	**125**
Illinois	2.51	2.28	3.54	3.08	3.16	147	147	147	112	112
Indiana	1.52	1.68	1.59	1.51	1.79	144	145	146	145	145
Michigan	—	—	—	—	—	—	—	—	—	—
Ohio	1.93	1.92	5.47	3.79	4.43	88	90	90	90	90
Wisconsin	2.08	2.13	.10	.08	.12	16	16	16	16	16
West North Central	**.58**	**.53**	**.56**	**.63**	**.54**	**78**	**78**	**78**	**78**	**77**
Iowa	1.56	1.37	1.39	1.41	1.21	202	202	202	202	202
Kansas	.49	.35	.38	.55	.34	61	61	61	61	61
Minnesota	.37	.39	.37	.46	.49	73	73	73	73	73
Missouri	1.20	1.36	1.05	NM	NM	50	50	50	50	50
Nebraska	—	—	—	—	—	—	—	—	—	—
North Dakota	.74	.72	.82	.83	.75	102	102	102	101	99
South Dakota	—	—	—	—	—	—	—	—	—	—
South Atlantic	**.95**	**.91**	**.83**	**1.00**	**1.05**	**120**	**120**	**116**	**117**	**118**
Delaware	—	—	—	—	—	—	—	—	—	—
District of Columbia	—	—	—	—	—	—	—	—	—	—
Florida	.87	.96	.90	.84	.95	73	73	67	72	72
Georgia	5.13	4.82	4.85	4.04	3.61	NM	NM	NM	NM	NM
Maryland	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	—	—	—	—
South Carolina	.48	.59	.49	.64	.89	43	43	43	43	43
Virginia	—	.20	.02	.02	.14	—	NM	NM	NM	NM
West Virginia	1.44	1.35	1.28	1.62	1.48	216	216	217	224	225
East South Central	**1.05**	**1.09**	**1.00**	**1.16**	**1.13**	**143**	**143**	**143**	**143**	**143**
Alabama	.57	.62	.75	1.02	.69	80	80	80	80	80
Kentucky	1.58	1.50	1.59	1.67	1.63	140	140	140	139	139
Mississippi	.35	.50	.68	.45	.46	70	70	70	70	70
Tennessee	.36	.37	.11	.18	.19	204	204	204	204	204
West South Central	**.91**	**.82**	**.81**	**.86**	**.82**	**71**	**83**	**86**	**89**	**91**
Arkansas	—	—	—	—	—	—	—	—	—	—
Louisiana	NM	NM	NM	NM	.81	75	75	75	75	75
Oklahoma	.59	1.14	1.26	.91	1.10	92	92	92	92	92
Texas	.93	.81	.79	.86	.81	70	83	87	90	92
Mountain	**.79**	**.70**	**.60**	**.57**	**.59**	**150**	**149**	**152**	**139**	**135**
Arizona	.88	.72	.33	.40	.52	175	175	180	180	175
Colorado	.85	.60	.49	.40	.43	69	69	64	64	70
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	1.14	.92	.97	.76	.80	274	274	274	274	267
Nevada	1.57	1.07	.47	.66	.72	126	126	126	126	126
New Mexico	1.03	.92	.90	.83	.74	165	162	162	93	93
Utah	.47	.52	.48	.47	.47	101	101	101	101	101
Wyoming	.61	.62	.63	.60	.64	137	137	137	137	137
Pacific Contiguous	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
California	—	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	—	—	—	—	—	—	—
Washington	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Alaska	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—
U.S. Average	**1.16**	**1.07**	**1.09**	**1.12**	**1.13**	**126**	**128**	**129**	**126**	**125**

O&M = Operation and Maintenance

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

Notes: •Data for 1999 are final pending approval by the Environmental Protection Agency. Data for prior years are final. •Totals may not equal sum of components because of independent rounding. •A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).

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

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Alabama Electric Coop, Inc							
Charles R Lowman 2	538	236	7903	1.90	Spray	Limestone	85.0
Charles R Lowman 3	—	236	8005	1.90	Spray	Limestone	85.0
Arizona Electric Pwr Coop, Inc							
Apache Station 2	464	195	7901	.70	Packed	Limestone	85.0
Apache Station 3	—	195	7901	.70	Packed	Limestone	85.0
Arizona Public Service Company							
Cholla 1	1,105	114	7312	1.00	Venturi	Lime	80.0
Cholla 2	—	289	7806	1.20	Venturi	Lime	90.0
Cholla 4	—	414	8106	1.20	Packed	Lime	95.0
Four Corners 1	2,270	190	7201	.80	Venturi	Lime	72.0
Four Corners 2	—	190	7201	.80	Venturi	Lime	72.0
Four Corners 3	—	253	7201	.80	Venturi	Lime	72.0
Four Corners 4	—	818	8501	.80	Tray	Dolomitic Limestone	72.0
Four Corners 5	—	818	8501	.80	Tray	Dolomitic Limestone	72.0
Atlantic City Electric Company							
B L England 2	476	163	9501	3.20	Spray	Limestone	93.0
AES Cayuga LLC							
AES Cayuga 1	322	322	9506	3.20	Spray	Limestone	95.0
AES Cayuga 2	—	322	9501	3.20	Spray	Limestone	95.0
AES Somerset LLC							
AES Somerset 1	655	655	8408	3.60	Spray	Limestone	90.0
Basin Electric Power Coop							
Antelope Valley FGD1	870	435	8307	1.20	Spray Dry	Lime/Alkaline Fly Ash	81.0
Antelope Valley FGD2	—	435	8511	1.20	Spray Dry	Lime/Alkaline Fly Ash	81.0
Laramie R Station 1	1,710	570	8007	.80	Spray	Limestone	90.0
Laramie R Station 2	—	570	8107	.80	Spray	Limestone	90.0
Laramie R Station 3	—	570	8405	.50	Spray Dry	Lime/Alkaline Fly Ash	85.0
Black Hills Corporation							
Neil Simpson II 2	—	—	9511	.90		Lime	92.0
Central Illinois Light Company							
Duck Creek 1	441	441	7607	3.40	Venturi	Limestone	86.0
Central Louisiana Elec Co Inc							
Dolet Hills 1	721	721	8604	.70	Spray	Limestone	76.0
Cincinnati Gas & Electric Co							
East Bend 2	669	669	8103	5.20	Spray Dry	Lime	99.0
W H Zimmer 1	1,426	1,426	9103	4.50	Spray	Lime	99.0
Columbus Southern Power Co							
Conesville 5	2,175	444	7705	7.90	Spray	Lime	89.7
Conesville 6	—	444	7708	7.90	Spray	Lime	89.7
Deseret Generation & Tran Coop							
Bonanza 1-1	400	400	8605	.50	Spray	Limestone	95.0
Duquesne Light Company							
Elrama SCRB	510	510	7609	2.50	Venturi	Lime	83.0
F R Phillips SCRB	411	411	7406	2.50	Venturi	Lime	83.0
East Kentucky Power Coop, Inc							
H L Spurlock 2	814	508	8306	3.60	Spray Dry	Lime	90.0
Georgia Power Company							
Yates Y1FG	1,488	123	9210	2.50	Bubbling Reactor	Limestone	90.0

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999 (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					
Grand Haven City of							
J B Sims 3	78	58	8308	2.80	Tray	Lime	90.0
Grand River Dam Authority							
GRDA 2	1,010	520	8604	1.50	Spray Dry	Lime/Alkaline Fly Ash	85.0
Great River Energy							
Coal Creek 1	1,210	605	7908	1.00	Spray	Lime	90.0
Coal Creek 2	—	605	8107	1.00	Spray	Lime	90.0
Elk River 1	46	46	8903	—	Spray Dry	Lime	90.0
Stanton 10	172	172	8206	.70	Spray Dry	Lime	70.0
Hamilton Dept of Public Utils							
Hamilton 9	111	51	9904	3.40	Other	Lime	90.0
Hoosier Energy R E C, Inc							
Merom 1FGD	1,080	540	8309	3.00	Spray	Limestone	90.0
Merom 2FGD	—	540	8202	3.00	Spray	Limestone	90.0
Indianapolis Power & Light Co							
Petersburg 1	1,873	253	9605	4.50	Spray	Limestone	95.0
Petersburg 2	—	471	9605	4.50	Spray	Limestone	95.0
Petersburg 3	—	574	7711	—	Tray	Limestone	85.0
Petersburg 4	—	574	8604	—	Spray	Limestone	95.0
JEA							
St Johns River Power 1	1,358	679	8703	2.20	Spray	Limestone	90.0
St Johns River Power 2	—	679	8805	2.20	Spray	Limestone	90.0
Kansas City Power & Light Co							
Lacygne 1	1,579	893	7306	5.40	Venturi	Limestone	80.0
Kentucky Utilities Company							
Ghent 1	2,226	557	9412	3.50	Spray	Limestone	95.0
Green River 1	264	75	7510	3.80	Venturi	Lime	80.0
Lakeland City of							
C D McIntosh Jr 3	593	364	8209	1.80	Spray	Limestone	85.0
Los Angeles Dept of Wtr & Pwr							
Intermountain 1CCC	1,640	820	8607	.60	Spray	Limestone	90.0
Intermountain 2CCC	—	820	8707	.60	Spray	Limestone	90.0
Louisville Gas & Electric Co							
Cane Run 4	645	163	7612	3.50	Spray	Other	85.0
Cane Run 5	—	209	7805	3.50	Spray	Other	85.0
Cane Run 6	—	272	7904	3.50	Tray	Other	90.0
Mill Creek 1	1,717	356	8112	6.00	Spray	Limestone	90.0
Mill Creek 2	—	356	8012	6.00	Spray	Limestone	90.0
Mill Creek 3	—	463	8510	5.00	Spray	Limestone	90.0
Mill Creek 4	—	544	8207	6.30	Spray	Limestone	90.0
Trimble County 1	566	566	9012	4.50	Spray	Limestone	90.7
Lower Colorado River Authority							
Sam Seymour 3	1,703	475	8804	1.70	Spray	Limestone	90.0
Marquette City of							
Shiras 3	40	40	8307	.50	Spray Dry	Limestone	80.0
Michigan South Central Pwr Agy							
Endicott Generating 1	55	50	8305	4.30	Spray	Limestone	90.0
Minnesota Power, Inc.							
Clay Boswell AQCS2	1,073	558	8004	1.00	Spray	Alkaline Fly Ash	83.2
Clay Boswell SCR3	—	365	7302	1.00	Spray	Alkaline Fly Ash	25.4

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Minnesota Power, Inc.							
Syl Laskin SCR1	116	58	7105	1.00	Spray	Alkaline Fly Ash	—
Syl Laskin SCR2	—	58	7105	1.00	Spray	Alkaline Fly Ash	—
Minnkota Power Coop, Inc							
Milton R Young FGD2	734	477	7806	1.20	Spray	Lime/Alkaline Fly Ash	77.9
Monongahela Power Company							
Harrison 1	2,052	684	9411	4.00	Spray	Lime	98.0
Harrison 2	—	684	9411	4.00	Spray	Lime	98.0
Harrison 3	—	684	9411	4.00	Spray	Lime	98.0
Pleasants 1	1,368	684	7903	4.50	Tray	Lime	90.0
Pleasants 2	—	684	8012	4.50	Tray	Lime	90.0
Montana Power Company							
Colstrip 1	2,327	358	7511	.80	Venturi	Lime/Alkaline Fly Ash	58.8
Colstrip 2	—	358	7608	.80	Venturi	Lime/Alkaline Fly Ash	58.8
Colstrip 3	—	805	8401	.80	Venturi	Lime/Alkaline Fly Ash	95.0
Colstrip 4	—	805	8604	.80	Venturi	Lime/Alkaline Fly Ash	95.0
Muscatine Power and Water							
Muscatine Plant # 1 9	294	176	8306	3.20	Spray	Limestone	96.0
Nevada Power Company							
Reid Gardner 1	612	114	7404	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 2	—	114	7404	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 3	—	114	7607	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 4	—	270	8307	.90	Spray	Sodium Carbonate	85.0
Northern Indiana Pub Serv Co							
Bailly 78	616	616	9206	—	Packed	Limestone	90.0
R M Schahfer 17	1,943	424	8304	3.20	Spray	Other	90.0
R M Schahfer 18	—	424	8602	3.20	Spray	Other	90.0
Northern States Power Company							
Riverside 7	404	165	8101	1.30	Spray Dry	Lime/Alkaline Fly Ash	70.0
Sherburne Co 1	2,129	660	7605	.90	Venturi	Limestone/Alk Fly Ash	50.0
Sherburne Co 2	—	660	7704	.90	Spray	Limestone/Alk Fly Ash	50.0
Sherburne Co 3	—	809	8711	.90	Spray Dry	Lime/Alkaline Fly Ash	72.3
Wilmarth 1	—	—	9101	—	Spray	Lime	70.0
Wilmarth 2	—	—	9101	—	Spray	Lime	70.0
Ohio Edison Company							
Niles 1	266	266	9510	3.00	Spray	Limestone	90.0
Ohio Power Company							
Gen J M Gavin 1	2,600	1,300	9412	3.50	Spray	Lime	95.0
Gen J M Gavin 2	—	1,300	9503	3.50	Spray	Lime	95.0
Orlando Utilities Commission							
Stanton Energy Ctr 1	929	465	8707	3.50	Spray	Limestone	90.0
Stanton Energy Ctr 2	—	465	9606	3.40	Spray	Limestone	95.0
Otter Tail Power Company							
Coyote FGD1	450	450	8105	.80	Spray Dry	Lime/Alkaline Fly Ash	70.0
Owensboro Municipal Utilities							
Elmer Smith FGD	445	445	9411	3.50	Spray	Limestone	96.0
PacifiCorp							
Dave Johnston SC44	817	360	7202	.40	Venturi	Lime	—
Hunter 1	1,339	446	7806	.60	Spray	Lime	80.0
Hunter 2	—	446	8006	.60	Spray	Lime	80.0
Hunter 3	—	446	8306	.60	Spray	Limestone	90.0
Huntington 1	893	446	7802	.60	Spray	Lime	80.0
Jim Bridger SC71	2,260	561	9009	1.00	Tray	Soda Liquor Waste	86.4

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
PacifiCorp							
Jim Bridger SC72	—	561	8609	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC73	—	578	8809	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC74	—	561	7911	1.00	Tray	Soda Liquor Waste	91.0
Naughton 3	707	326	8110	.80	Tray	Sodium Carbonate	70.0
Wyodak SC91	362	362	8612	.80	Spray Dry	Lime	75.2
Pennsylvania Power Company							
Bruce Mansfield 1	2,741	914	7604	4.80	Venturi	Lime	92.1
Bruce Mansfield 2	—	914	7710	4.80	Venturi	Lime	92.1
Bruce Mansfield 3	—	914	8009	4.80	Spray	Lime	92.1
Plains Elec Gen&Trans Coop Inc							
Escalante 1	257	257	8412	.80	Spray	Limestone	95.0
Platte River Power Authority							
Rawhide 101	294	294	8404	.30	Spray Dry	Lime/Alkaline Fly Ash	80.0
Public Service Co of Colorado							
Arapahoe 4	232	100	9306	.40	Spray Dry	Other	20.0
Cherokee 1	710	100	9802	.40	Spray Dry	Other	50.0
Cherokee 4	—	350	8905	.40	Spray Dry	Other	26.0
Hayden H1	465	190	9812	.40	Spray Dry	Lime/Alkaline Fly Ash	85.0
Hayden H2	—	275	9906	.40	Spray Dry	Lime/Alkaline Fly Ash	85.0
Public Service Company of NM							
San Juan 1	1,848	369	9810	.90	Spray	Limestone	75.0
San Juan 2	—	369	9810	.90	Spray	Limestone	75.0
San Juan 3	—	555	9810	.90	Spray	Limestone	75.0
San Juan 4	—	555	9810	.90	Spray	Limestone	75.0
PECO Energy Company							
Cromby 1	418	188	8212	2.60	Spray	Magnesium Oxide	95.0
Eddystone 1	1,489	354	8212	2.60	Spray	Magnesium Oxide	92.0
Eddystone 2	—	354	8212	2.60	Spray	Magnesium Oxide	92.0
PSI Energy Inc							
Gibson 4	3,340	668	9501	3.50	Spray	Limestone	92.0
Gibson 5	—	668	8210	4.40	Spray	Limestone	86.0
Reliant Energy HL&P							
Limestone FGD1	1,627	813	8510	3.10	Spray	Limestone	90.0
Limestone FGD2	—	813	8610	3.10	Spray	Limestone	90.0
W A Parish FGD8	3,953	615	8212	.50	Spray	Limestone	85.0
Richmond City of							
Whitewater Valley LFC	—	—	9410	2.10	Spray Dry	Limestone	72.5
Salt River Project							
Coronado FGD1	822	411	7912	1.00	Spray	Limestone	82.5
Coronado FGD2	—	411	8011	1.00	Spray	Limestone	82.5
Navajo 1	2,409	803	9908	.60	Spray	Limestone	92.0
Navajo 2	—	803	9811	.60	Spray	Limestone	92.0
Navajo 3	—	803	9711	.60	Spray	Limestone	92.0
San Antonio Public Service Bd							
J K Spruce FGD1	546	546	9212	.60	Spray	Limestone	70.0
San Miguel Electric Coop, Inc							
San Miguel SM-1	410	410	8201	2.00	Spray	Limestone	86.0
Seminole Electric Coop, Inc							
Seminole 1	1,429	715	8402	3.00	Spray	Limestone	90.0
Seminole 2	—	715	8412	3.00	Spray	Limestone	90.0

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999 (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					
Sierra Pacific Power Company							
Valmy 2	521	267	8507	0.50	Spray Dry	Lime	70.0
Sikeston City of							
Sikeston 1	261	261	8111	2.80	Venturi	Limestone	75.5
South Carolina Electric&Gas Co							
Cope COP1	417	417	9511	1.90	Spray Dry	Lime	95.0
South Carolina Pub Serv Auth							
Cross 1	1,147	591	9505	1.10	Spray	Limestone	90.0
Cross 2	—	556	8312	1.60	Spray	Limestone	81.4
Winyah 2	1,260	315	7707	1.10	Venturi	Limestone	45.0
Winyah 3	—	315	8006	2.30	Spray	Limestone	90.0
Winyah 4	—	315	8111	1.70	Spray	Limestone	90.4
South Mississippi El Pwr Assn							
R D Morrow 1	400	200	7809	1.50	Spray	Limestone	52.7
R D Morrow 2	—	200	7906	1.50	Spray	Limestone	52.7
Southern Illinois Power Coop							
Marion 4	272	173	7904	4.40	Venturi	Limestone	89.4
Southern Indiana Gas & Elec Co							
A B Brown 1	530	265	7904	4.50	Spray	Sodium Ash	85.0
A B Brown 2	—	265	8602	4.50	Spray	Sodium Ash	90.0
F B Culley 2-3	415	369	9501	3.80	Spray	Limestone	95.0
Southwestern Electric Power Co							
Pirkey 1	721	721	8501	1.50	Spray	Limestone	85.0
Soyland Power Coop Inc							
Pearl Station 1A	22	22	7611	3.40	Venturi	Other	11.8
Springfield City of							
Southwest Power St 1	194	194	7704	3.20	Tray	Limestone	87.0
Springfield Water Light&Power							
Dallman 33	388	207	8012	3.30	Packed	Limestone	95.0
Sunflower Electric Power Corp							
Holcomb SDA1	349	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb SDA2	—	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb SDA3	—	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
SITHE Northeast Managment Co							
Conemaugh 1	1,872	936	9412	2.70	Spray	Limestone	95.0
Conemaugh 2	—	936	9511	2.70	Spray	Limestone	95.0
Tampa Electric Company							
Big Bend FGD1	1,823	891	9912	3.30	Spray	Limestone	95.0
Big Bend FGD4	—	932	8502	3.50	Spray	Limestone	95.0
Tennessee Valley Authority							
Cumberland 1	2,600	1,300	9501	4.00	Spray	Limestone	95.0
Cumberland 2	—	1,300	9501	4.00	Spray	Limestone	95.0
Paradise 1	2,558	704	8309	3.20	Spray	Limestone	84.2
Paradise 2	—	704	8312	3.20	Spray	Limestone	84.2
Widows Creek 7	1,969	575	8112	4.00	Spray	Limestone	83.4
Widows Creek 8	—	550	7801	4.50	Tray	Limestone	80.0
Texas Municipal Power Agency							
Gibbons Creek 1	444	444	8310	.30	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 1999 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Tri-State G & T Assn, Inc							
Craig C1	1,339	446	8010	0.60	Spray	Limestone	85.0
Craig C2	—	446	8005	.60	Spray	Limestone	85.0
Craig C3	—	446	8410	.70	Spray Dry	Lime	85.0
Tucson Electric Power Company							
Springerville 1	850	425	8506	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3
Springerville 2	—	425	9006	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3
TXU Electric Company							
Martin Lake 1	2,380	793	7705	.90	Spray	Limestone	91.0
Martin Lake 2	—	793	7805	.90	Spray	Limestone	91.0
Martin Lake 3	—	793	7904	.90	Spray	Limestone	91.0
Monticello 3	1,980	793	7808	1.50	Spray	Limestone	74.0
Sandow 4	591	591	8105	1.60	Spray	Limestone	73.9
Virginia Electric & Power Co							
Clover 1	848	424	9510	2.00	Spray	Limestone	90.0
Clover 2	—	424	9603	2.00	Spray	Limestone	90.0
Mt Storm 3	1,662	522	9501	2.00	Spray	Limestone	90.0
West Penn Power Company							
Mitchell 33	449	299	8208	4.00	Spray	Lime	95.0
West Texas Utilities Company							
Oklaunion 1	720	720	8612	.40	Spray	Limestone	86.8
Western Kentucky Energy Corp							
D B Wilson W1	509	509	8611	3.80	Spray	Limestone	90.0
HMP&L Station 2 H1	365	180	9506	4.20	Tray	Lime	95.0
HMP&L Station 2 H2	—	185	9506	4.20	Tray	Lime	95.0
R D Green G1	527	264	7912	4.00	Spray	Lime	90.0
R D Green G2	—	264	8101	4.00	Spray	Lime	90.0
Western Resources, Inc							
Jeffrey EC 1	2,160	720	7807	.30	Spray	Limestone	60.0
Jeffrey EC 2	—	720	8005	.30	Spray	Limestone	60.0
Jeffrey EC 3	—	720	8305	.30	Spray	Limestone	60.0
Lawrence EC 4N	604	114	6906	.90	Venturi	Limestone	73.0
Lawrence EC 4S	—	114	6906	.90	Venturi	Limestone	73.0
Lawrence EC 5	—	403	7105	.90	Venturi	Limestone	52.0
Wisconsin Electric Power Co							
Port Washington 1	320	80	9308	1.20	Spray	Sodium Carbonate	50.0
Port Washington 4	—	80	9408	1.20	Spray	Sodium Carbonate	50.0

Notes: •Data for 1999 are final pending approval by the Environmental Protection Agency. • SO2 = Sulfur Dioxide; WT=weight; FGD=Flue Gas Desulfurization.

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

U.S. Electric Power Transactions

This chapter provides summary information for the U.S. electric power industry on its operations and wholesale electricity trade at the international (Canada and Mexico), national, and North American Electric Reliability Council (NERC) region levels.[10] 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.

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

Electric Utility Transactions

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

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

Power Pool Transactions

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

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

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

NERC Profile

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

Regulation of U.S. Electric Utility Transactions

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

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

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

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

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

Other Wholesale Electricity Trade Concerns

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

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

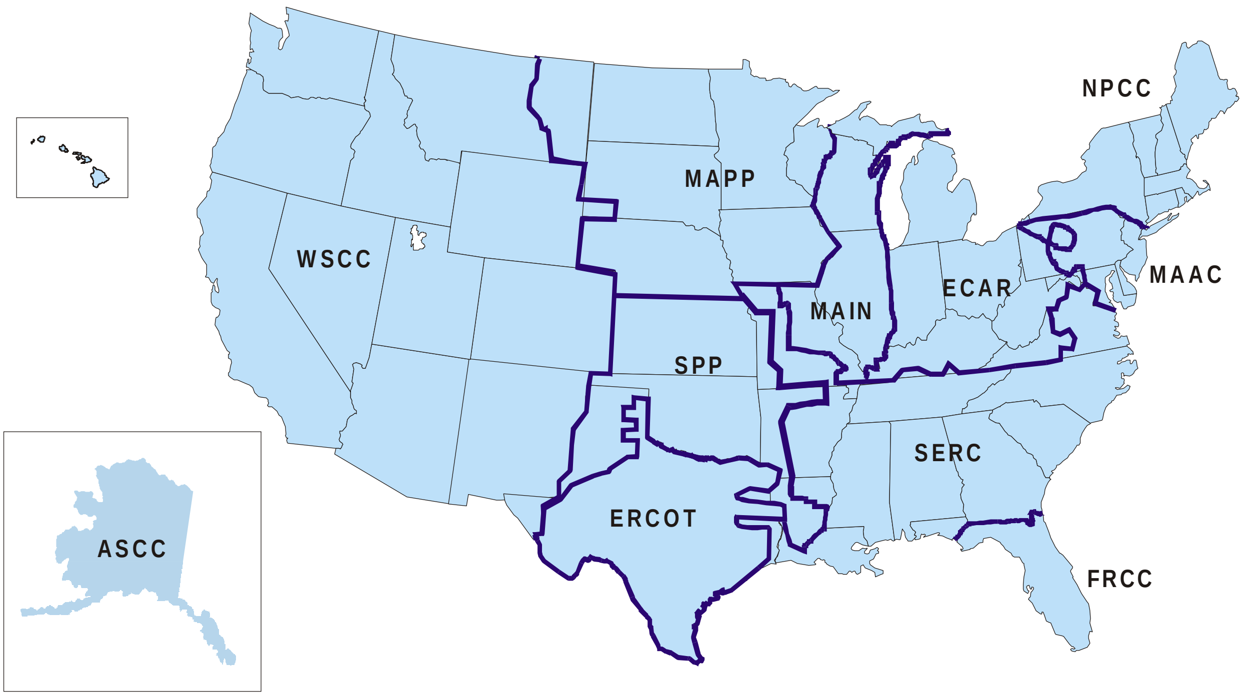
International Transactions

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

Data Sources

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

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



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

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

Table 31. Sources and Disposition of Electricity at U.S. Electric Utilities, 1995 Through 1999
(Million Kilowatthours)

Item	1995	1996	1997	1998	1999
Source					
Net Generation	3,002,304	3,099,945	3,144,756	3,219,994	3,189,466
Purchases from Utilities	1,284,995	1,465,174	1,634,886	1,668,665	1,633,818
Purchases from Nonutilities	222,092	229,018	243,213	258,534	315,757
Net Exchange	66	–11,677	–17,088	–858	1,787
Net Wheeling	7,016	7,324	7,135	8,076	8,361
Disposition					
Sales to Ultimate Consumers	3,013,287	3,097,810	3,139,761	3,239,818	3,235,899
Requirements and Nonrequirements Sales for Resale	1,255,618	1,431,179	1,616,318	1,664,081	1,635,614
Energy Furnished Without Charge	5,362	6,205	6,318	5,109	5,054
Energy Used by Utility Electric Department	12,455	13,886	13,424	10,808	12,557
Energy Losses[1]	228,076	238,695	234,926	232,112	250,193

[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 are final. •Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Differences in this net generation data and net generation reported on the Form EIA-759, ''Monthly Power Plant Report,'' (Table 1) occur due to the time frame in reporting. Since the components of net generation are provided monthly by the Form EIA-759 by prime mover and energy source, the Form EIA-759 is used as the official Energy Information Administration source for net generation. •Totals may not equal sum of components because of independent rounding. •''Sales to Ultimate Consumers'' for the years 1996, 1997, 1998 and 1999 do not include sales by retail power marketers in state-level deregulated markets. For further information on these transactions see *Electric Sales and Revenue* for those years. •The source and disposition of electricity represent the total volume of energy transactions between utilities. These data should not be summed as they are the aggregation of data reported for each utility and could be double counted due to the nature and types of electricity trade. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist.

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

Table 32. Net Generation from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1995	1996	1997	1998	1999
ECAR	509,468	528,214	530,896	528,252	529,712
ERCOT	210,596	218,497	221,407	237,176	232,726
FRCC	—	—	146,217	167,910	165,058
MAAC	203,801	200,669	204,269	222,509	217,624
MAIN	229,424	231,315	216,732	221,883	237,971
MAPP(U.S.)	130,637	132,689	133,885	139,209	146,186
NPCC(U.S.)	183,021	185,521	188,063	178,096	138,380
SERC	703,899	740,784	617,191	747,031	748,523
SPP	274,475	276,205	278,701	184,483	179,774
WSCC(U.S.)	546,208	574,878	596,496	582,768	582,448
Contiguous U.S.	**2,991,529**	**3,088,772**	**3,133,858**	**3,209,317**	**3,178,401**
ASCC	4,925	5,178	5,013	4,719	4,949
Hawaii[1]	5,851	5,994	5,886	5,958	6,115
U.S. Total	**3,002,304**	**3,099,945**	**3,144,756**	**3,219,994**	**3,189,466**

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

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

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

Table 33. U.S. Electric Utility Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1995 Through 1999

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1995		
ECAR	477,126	147,019	116,092	204,072	9,942
ERCOT	222,465	81,158	59,065	72,542	9,700
FRCC	—	—	—	—	—
MAAC	227,532	79,483	86,687	58,440	2,922
MAIN	218,728	66,039	62,774	80,711	9,204
MAPP(U.S.)	134,495	47,489	29,530	53,636	3,840
NPCC(U.S.)	238,492	78,615	94,185	51,661	14,031
SERC	686,458	273,502	172,424	221,297	19,234
SPP	266,912	93,533	67,399	97,392	8,588
WSCC(U.S.)	527,641	171,479	169,704	168,739	17,719
Contiguous U.S.	**2,999,849**	**1,038,317**	**857,860**	**1,008,492**	**95,179**
ASCC	4,631	1,713	2,200	546	172
Hawaii	8,806	2,471	2,625	3,655	55
U.S. Total	**3,013,287**	**1,042,501**	**862,685**	**1,012,693**	**95,407**
			1996		
ECAR	483,750	149,381	117,924	206,397	10,048
ERCOT	235,780	87,324	60,959	77,113	10,383
FRCC	—	—	—	—	—
MAAC	229,013	81,141	87,597	57,336	2,939
MAIN	219,978	66,015	63,919	80,655	9,390
MAPP(U.S.)	137,767	48,099	30,233	55,600	3,835
NPCC(U.S.)	241,258	79,650	95,532	52,236	13,840
SERC	714,441	288,556	178,815	227,381	19,689
SPP	277,115	96,689	70,230	101,332	8,864
WSCC(U.S.)	544,937	181,329	177,304	167,988	18,316
Contiguous U.S.	**3,084,040**	**1,078,184**	**882,513**	**1,026,039**	**97,304**
ASCC	4,779	1,766	2,250	584	179
Hawaii	8,991	2,540	2,662	3,733	55
U.S. Total	**3,097,810**	**1,082,491**	**887,425**	**1,030,356**	**97,539**
			1997		
ECAR	485,244	146,537	119,440	209,236	10,030
ERCOT	243,029	88,459	61,965	81,583	11,022
FRCC	149,249	73,598	56,159	14,364	5,128
MAAC	228,115	79,143	88,156	57,952	2,864
MAIN	222,714	65,456	64,920	82,790	9,548
MAPP(U.S.)	141,200	48,375	30,738	58,069	4,019
NPCC(U.S.)	242,428	79,286	97,605	51,641	13,896
SERC	571,424	208,635	152,495	195,263	15,030
SPP	282,082	97,417	71,826	103,442	9,398
WSCC(U.S.)	560,473	184,603	180,278	173,858	21,734
Contiguous U.S.	**3,125,958**	**1,071,510**	**923,583**	**1,028,197**	**102,668**
ASCC	4,840	1,726	2,180	756	178
Hawaii	8,963	2,531	2,677	3,701	55
U.S. Total	**3,139,761**	**1,075,767**	**928,440**	**1,032,653**	**102,901**

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, 1995 Through 1999 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1998		
ECAR	494,942	149,895	124,956	210,679	9,411
ERCOT	258,684	96,749	66,654	83,395	11,886
FRCC	175,214	89,614	63,480	16,384	5,736
MAAC	230,855	79,331	90,719	58,007	2,798
MAIN	224,576	67,011	66,753	81,167	9,646
MAPP(U.S.)	143,942	48,651	31,625	59,725	3,941
NPCC(U.S.)	243,180	79,623	97,862	51,396	14,298
SERC	723,580	266,502	187,200	251,340	18,538
SPP	165,351	58,274	48,405	51,991	6,680
WSCC(U.S.)	565,531	187,814	185,893	171,497	20,327
Contiguous U.S.	**3,225,854**	**1,123,463**	**963,546**	**1,035,583**	**103,261**
ASCC	5,095	1,768	2,307	818	202
Hawaii[2]	8,870	2,504	2,675	3,636	55
U.S. Total	**3,239,818**	**1,127,735**	**968,528**	**1,040,038**	**103,518**
			1999		
ECAR	506,007	155,266	126,202	214,969	9,571
ERCOT	257,735	95,278	68,391	82,090	11,975
FRCC	174,971	87,680	65,042	16,519	5,729
MAAC	207,250	81,379	83,213	39,893	2,765
MAIN	228,164	67,191	70,514	80,503	9,956
MAPP(U.S.)	147,503	50,094	33,181	60,257	3,970
NPCC(U.S.)	244,211	84,779	94,474	50,674	14,284
SERC	733,887	267,208	192,739	254,914	19,026
SPP	160,826	55,463	48,130	50,833	6,400
WSCC(U.S.)	561,067	192,006	183,548	162,689	22,824
Contiguous U.S.	**3,221,621**	**1,136,345**	**965,434**	**1,013,341**	**106,502**
ASCC	5,293	1,866	2,385	844	198
Hawaii[2]	8,985	2,551	2,782	3,598	55
U.S. Total	**3,235,899**	**1,140,761**	**970,601**	**1,017,783**	**106,754**

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

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

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

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

Table 34. Generating Capability at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1995	1996	1997	1998	1999
ECAR	104,426	103,360	102,518	101,115	102,942
ERCOT	53,400	53,903	53,711	54,018	54,184
FRCC	—	32,751	32,616	34,904	34,980
MAAC	52,083	53,163	53,588	53,168	42,944
MAIN	51,430	52,155	52,093	49,020	35,762
MAPP(U.S.)	31,311	30,610	34,820	34,815	34,813
NPCC(U.S.)	55,567	52,177	R 51,310	R 43,166	R 26,031
SERC	153,434	125,079	155,786	154,320	153,682
SPP	71,375	71,593	42,871	42,669	42,801
WSCC(U.S.)	129,751	131,292	129,232	116,159	107,832
Contiguous U.S.	**702,777**	**706,083**	R **708,545**	R **683,354**	R **635,971**
ASCC	1,732	1,734	1,750	1,721	1,744
Hawaii	1,602	1,610	R 1,595	R 1,616	R 1,608
U.S. Total	**706,111**	**709,942**	**711,889**	**686,692**	**639,324**

R = Revised data.

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

Sources: Energy Information Administration, Data for 1999 and 1998: Form EIA-860A, ''Annual Electric Generator Report - Utility''; Data for 1997 and prior: Form EIA-860, ''Annual Electric Generator Report''.

Table 35. Noncoincidental Peak Load, Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1995 Through 2004
(Megawatts)

North American Electric Reliability Council Region and Hawaii	Actual				
	1995	1996	1997[1]	1998[1]	1999
	Summer				
ECAR	92,619	90,798	93,492	93,784	99,239
ERCOT	46,618	47,480	50,541	54,666	55,529
FRCC	NA	NA	35,375	38,730	37,493
MAAC	48,577	44,302	49,464	48,445	51,645
MAIN	45,782	46,402	45,887	47,509	51,535
MAPP(U.S.)	29,192	28,253	29,787	30,722	31,903
NPCC(U.S.)	47,705	45,094	49,269	49,566	52,855
SERC	146,569	145,650	137,382	143,226	149,012
SPP	59,595	60,072	36,479	37,724	38,609
WSCC(U.S.)	103,592	108,739	110,001	115,921	113,629
Contiguous U.S.	**620,249**	**616,790**	**637,677**	**660,293**	**681,449**
ASCC	622	(2)	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**620,871**	**616,790**	**637,677**	**660,293**	**681,449**
	Winter				
ECAR	83,465	84,534	75,760	84,401	86,239
ERCOT	36,965	38,868	37,966	41,876	39,164
FRCC	NA	NA	33,076	39,975	40,178
MAAC	40,790	40,468	37,217	36,532	40,220
MAIN	35,734	37,162	34,973	37,410	39,081
MAPP(U.S.)	23,429	24,251	25,390	26,080	25,200
NPCC(U.S.)	42,755	41,208	41,338	44,119	45,227
SERC	142,032	143,060	122,649	127,416	128,563
SPP	44,626	49,095	27,437	27,847	27,963
WSCC(U.S.)	94,890	95,435	94,158	101,822	99,080
Contiguous U.S.	**544,684**	**554,081**	**529,874**	**567,558**	**570,915**
ASCC	676	(2)	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**545,360**	**554,081**	**529,874**	**567,558**	**570,915**

See footnotes at end of table.

Table 35. Noncoincidental Peak Load, Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1995 Through 2004 (Continued)

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Projected				
	2000	2001	2002	2003	2004
	Summer				
ECAR	97,557	99,562	101,256	103,299	105,105
ERCOT	54,817	56,501	58,079	59,637	61,129
FRCC	37,728	38,445	39,282	40,157	41,004
MAAC	51,206	51,762	52,509	53,474	54,288
MAIN	51,271	52,128	52,922	53,780	54,697
MAPP(U.S.)	32,899	33,490	33,643	33,737	34,040
NPCC(U.S.)	53,450	54,170	54,836	55,588	56,205
SERC	151,065	156,533	160,446	163,643	166,505
SPP	39,383	40,127	41,087	41,876	42,715
WSCC(U.S.)	116,440	119,130	121,465	123,974	126,477
Contiguous U.S.	**685,816**	**701,848**	**715,525**	**729,165**	**742,165**
ASCC	(2)	(2)	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**685,816**	**701,848**	**715,525**	**729,165**	**742,165**
	Winter				
ECAR	86,455	87,892	89,424	90,924	92,429
ERCOT	44,287	45,757	46,926	48,243	49,642
FRCC	40,894	41,811	42,739	43,663	44,638
MAAC	43,139	43,717	44,455	45,143	45,767
MAIN	39,742	40,399	41,060	41,739	42,432
MAPP(U.S.)	27,363	27,869	27,940	27,917	28,192
NPCC(U.S.)	45,170	45,610	46,163	46,773	47,369
SERC	134,488	137,753	140,207	142,549	145,638
SPP	28,375	28,950	29,904	30,575	31,262
WSCC(U.S.)	102,435	104,876	106,837	108,869	110,945
Contiguous U.S.	**592,348**	**604,634**	**615,655**	**626,395**	**638,314**
ASCC	(2)	(2)	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**592,348**	**604,634**	**615,655**	**626,395**	**638,314**

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

Notes: •Actual data are final. •Projected data are updated annually. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of indepent rounding. •Represents an hour of a day during the associated peak period. •The summer peak period begins on June 1 and extends through September 30. •The winter peak period begins on December 1 and extends through March 31 of the following year. For example, winter 2000 begins December 1, 2000, and extends through March 31, 2001. Thus, the winter referred to here would be the winter of 2000/2001.

Sources: Data for 1996 and beyond: Form EIA-411, ‘‘Coordinated Bulk Power Supply Program’’; Data for 1995: 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, 1995 Through 1999

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts	Purchased Power	Exchange Received	Wheeling Received
		1995		
ECAR	223,966	188,679	2,158	33,128
ERCOT	145,430	62,215	50,420	33,795
FRCC	—	—	—	—
MAAC	114,216	98,773	528	14,915
MAIN	67,367	60,707	389	6,270
MAPP(U.S.)	112,956	92,315	2,826	17,816
NPCC(U.S.)	262,947	199,059	3,998	59,890
SERC	426,796	354,477	41,550	30,769
SPP	176,109	147,082	5,525	23,502
WSCC(U.S.)	484,202	297,960	51,633	134,610
Contiguous U.S.	**2,013,988**	**1,500,268**	**159,026**	**354,694**
ASCC	4,217	3,301	137	779
Hawaii	3,522	3,518	4	0
U.S. Total	**2,021,728**	**1,507,087**	**159,167**	**355,473**
		1996		
ECAR	264,825	203,637	1,361	59,827
ERCOT	148,971	73,590	55,354	20,027
FRCC	—	—	—	—
MAAC	141,448	120,701	474	20,272
MAIN	75,234	67,287	252	7,695
MAPP(U.S.)	124,893	102,960	4,189	17,744
NPCC(U.S.)	276,773	209,271	3,799	63,703
SERC	454,193	384,930	31,998	37,264
SPP	198,090	166,768	5,340	25,982
WSCC(U.S.)	574,451	358,142	51,859	164,449
Contiguous U.S.	**2,258,877**	**1,687,286**	**154,627**	**416,964**
ASCC	4,257	3,338	99	820
Hawaii	3,572	3,568	4	0
U.S. Total	**2,266,707**	**1,694,192**	**154,731**	**417,784**
		1997		
ECAR	319,495	259,081	1,764	58,650
ERCOT	134,715	78,170	56,545	[1] 0
FRCC	50,820	40,140	33	10,647
MAAC	151,729	135,582	518	15,629
MAIN	105,159	88,743	294	16,121
MAPP(U.S.)	132,758	108,253	3,814	20,691
NPCC(U.S.)	290,015	201,349	4,879	83,786
SERC	425,460	343,939	29,589	51,932
SPP	210,562	169,136	9,780	31,645
WSCC(U.S.)	645,818	446,733	47,919	151,166
Contiguous U.S.	**2,466,530**	**1,871,127**	**155,135**	**440,268**
ASCC	4,267	3,348	79	840
Hawaii	3,627	3,625	2	0
U.S. Total	**2,474,424**	**1,878,099**	**155,217**	**441,108**

See footnotes at end of table.

Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts	Purchased Power	Exchange Received	Wheeling Received
		1998		
ECAR	350,223	276,928	6,974	66,322
ERCOT	137,785	82,765	54,389	[1] 631
FRCC	67,693	55,730	42	11,921
MAAC	158,175	145,124	733	12,318
MAIN	117,000	88,766	570	27,664
MAPP(U.S.)	136,784	109,152	4,222	23,409
NPCC(U.S.)	272,560	209,550	4,798	58,212
SERC	532,068	434,074	19,662	78,332
SPP	110,978	84,182	5,229	21,568
WSCC(U.S.)	622,881	433,920	36,989	151,972
Contiguous U.S.	**2,506,147**	**1,920,191**	**133,607**	**452,350**
ASCC	4,064	3,570	115	379
Hawaii	3,440	3,437	3	0
U.S. Total	**2,513,651**	**1,927,198**	**133,725**	**452,728**
		1999		
ECAR	337,502	265,186	1,326	70,991
ERCOT	120,461	84,138	35,991	[1] 332
FRCC	73,564	57,944	27	15,592
MAAC	136,548	122,286	3,419	10,843
MAIN	102,812	72,580	577	29,654
MAPP(U.S.)	141,133	109,527	3,505	28,101
NPCC(U.S.)	323,278	229,339	4,031	89,909
SERC	531,326	435,424	25,258	70,644
SPP	120,514	87,651	4,586	28,277
WSCC(U.S.)	669,330	478,550	34,162	156,618
Contiguous U.S.	**2,556,468**	**1,942,625**	**112,882**	**500,961**
ASCC	3,840	3,562	108	170
Hawaii	3,394	3,387	6	0
U.S. Total	**2,563,702**	**1,949,574**	**112,997**	**501,131**

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

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

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

Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1995		
ECAR	221,627	186,464	2,270	32,893
ERCOT	118,456	34,017	50,644	33,796
FRCC	—	—	—	—
MAAC	71,357	56,800	9	14,548
MAIN	61,427	55,044	209	6,175
MAPP(U.S.)	95,503	74,621	4,285	16,596
NPCC(U.S.)	186,345	124,463	2,256	59,626
SERC	393,683	327,687	37,116	28,880
SPP	161,207	132,687	5,113	23,406
WSCC(U.S.)	449,423	260,585	57,080	131,758
Contiguous U.S.	**1,759,028**	**1,252,369**	**158,981**	**347,678**
ASCC	4,138	3,250	109	779
Hawaii	11	0	11	0
U.S. Total	**1,763,177**	**1,255,618**	**159,101**	**348,457**
		1996		
ECAR	274,275	213,373	1,381	59,522
ERCOT	115,163	39,924	55,230	20,009
FRCC	—	—	—	—
MAAC	93,421	73,221	22	20,177
MAIN	69,301	61,421	330	7,550
MAPP(U.S.)	104,835	82,899	5,479	16,457
NPCC(U.S.)	201,223	135,832	1,991	63,400
SERC	429,948	352,216	42,307	35,425
SPP	174,435	143,548	5,017	25,870
WSCC(U.S.)	541,181	325,405	54,546	161,230
Contiguous U.S.	**2,003,783**	**1,427,839**	**166,304**	**409,640**
ASCC	4,257	3,340	97	820
Hawaii	7	0	7	0
U.S. Total	**2,008,047**	**1,431,179**	**166,407**	**410,460**
		1997		
ECAR	329,876	269,688	1,782	58,406
ERCOT	96,812	40,346	56,467	[1] 0
FRCC	37,627	27,182	19	10,426
MAAC	108,060	92,418	16	15,626
MAIN	83,187	66,939	331	15,918
MAPP(U.S.)	112,294	89,619	3,306	19,370
NPCC(U.S.)	215,175	128,369	3,315	83,491
SERC	431,021	336,819	44,850	49,352
SPP	183,461	141,120	10,656	31,685
WSCC(U.S.)	621,041	420,704	51,476	148,860
Contiguous U.S.	**2,218,554**	**1,613,202**	**172,219**	**433,133**
ASCC	4,037	3,115	82	840
Hawaii	4	0	4	0
U.S. Total	**2,222,596**	**1,616,318**	**172,305**	**433,973**

See footnotes at end of table.

Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1998		
ECAR	347,326	275,006	7,043	65,277
ERCOT	98,143	42,958	54,570	[1] 615
FRCC	47,955	36,226	56	11,673
MAAC	131,873	119,627	13	12,233
MAIN	99,397	71,254	618	27,525
MAPP(U.S.)	117,460	92,457	3,623	21,380
NPCC(U.S.)	188,205	126,177	4,127	57,902
SERC	503,114	399,718	26,469	76,927
SPP	115,035	88,547	5,051	21,438
WSCC(U.S.)	591,499	409,307	32,888	149,304
Contiguous U.S.	**2,240,008**	**1,661,277**	**134,458**	**444,274**
ASCC	3,301	2,803	119	379
Hawaii	6	0	6	0
U.S. Total	**2,243,316**	**1,664,081**	**134,583**	**444,652**
		1999		
ECAR	324,482	252,377	1,437	70,668
ERCOT	78,721	41,992	36,675	[1] 55
FRCC	51,856	36,505	24	15,327
MAAC	129,074	118,311	5	10,758
MAIN	94,847	64,279	1,010	29,559
MAPP(U.S.)	124,835	96,041	3,063	25,731
NPCC(U.S.)	201,577	108,857	3,016	89,704
SERC	492,886	398,431	25,910	68,545
SPP	123,909	91,299	4,576	28,035
WSCC(U.S.)	614,319	424,720	35,380	154,219
Contiguous U.S.	**2,236,507**	**1,632,810**	**111,096**	**492,601**
ASCC	3,086	2,804	111	170
Hawaii	2	0	2	0
U.S. Total	**2,239,595**	**1,635,614**	**111,210**	**492,771**

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

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

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

Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1995	
ECAR	2,339	223,966	221,627
ERCOT	26,974	145,430	118,456
FRCC	—	—	—
MAAC	42,859	114,216	71,357
MAIN	5,940	67,367	61,427
MAPP(U.S.)	17,453	112,956	95,503
NPCC(U.S.)	76,602	262,947	186,345
SERC	33,112	426,796	393,683
SPP	14,902	176,109	161,207
WSCC(U.S.)	34,779	484,202	449,423
Contiguous U.S.	**254,960**	**2,013,988**	**1,759,028**
ASCC	79	4,217	4,138
Hawaii	3,512	3,522	11
U.S. Total	**258,551**	**2,021,728**	**1,763,177**
		1996	
ECAR	–9,450	264,825	274,275
ERCOT	33,808	148,971	115,163
FRCC	—	—	—
MAAC	48,027	141,448	93,421
MAIN	5,933	75,234	69,301
MAPP(U.S.)	20,058	124,893	104,835
NPCC(U.S.)	75,550	276,773	201,223
SERC	24,245	454,193	429,948
SPP	23,655	198,090	174,435
WSCC(U.S.)	33,270	574,451	541,181
Contiguous U.S.	**255,095**	**2,258,877**	**2,003,783**
ASCC	0	4,257	4,257
Hawaii	3,565	3,572	7
U.S. Total	**258,660**	**2,266,707**	**2,008,047**
		1997	
ECAR	–10,381	319,495	329,876
ERCOT	37,903	134,715	96,812
FRCC	13,192	50,820	37,627
MAAC	43,669	151,729	108,060
MAIN	21,971	105,159	83,187
MAPP(U.S.)	20,463	132,758	112,294
NPCC(U.S.)	74,840	290,015	215,175
SERC	–5,561	425,460	431,021
SPP	27,101	210,562	183,461
WSCC(U.S.)	24,778	645,818	621,041
Contiguous U.S.	**247,976**	**2,466,530**	**2,218,554**
ASCC	230	4,267	4,037
Hawaii	3,623	3,627	4
U.S. Total	**251,828**	**2,474,424**	**2,222,596**

See footnotes at end of table.

Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1998	
ECAR	2,897	350,223	347,326
ERCOT	39,642	137,785	98,143
FRCC	19,738	67,693	47,955
MAAC	26,302	158,175	131,873
MAIN	17,603	117,000	99,397
MAPP(U.S.)	19,324	136,784	117,460
NPCC(U.S.)	84,355	272,560	188,205
SERC	28,954	532,068	503,114
SPP	–4,057	110,978	115,035
WSCC(U.S.)	31,382	622,881	591,499
Contiguous U.S.	**266,139**	**2,506,147**	**2,240,008**
ASCC	763	4,064	3,301
Hawaii	3,434	3,440	6
U.S. Total	**270,336**	**2,513,651**	**2,243,316**
		1999	
ECAR	13,020	337,502	324,482
ERCOT	41,740	120,461	78,721
FRCC	21,708	73,564	51,856
MAAC	7,474	136,548	129,074
MAIN	7,964	102,812	94,847
MAPP(U.S.)	16,298	141,133	124,835
NPCC(U.S.)	121,701	323,278	201,577
SERC	38,440	531,326	492,886
SPP	–3,395	120,514	123,909
WSCC(U.S.)	55,011	669,330	614,319
Contiguous U.S.	**319,961**	**2,556,468**	**2,236,507**
ASCC	755	3,840	3,086
Hawaii	3,392	3,394	2
U.S. Total	**324,108**	**2,563,702**	**2,239,595**

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

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

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

Table 39. U.S. Electric Utility Purchases of Nonutility Generated Electricity by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1995	1996	1997	1998	1999
ECAR	13,131	15,861	15,989	14,692	15,113
ERCOT	22,653	23,916	25,908	26,562	22,159
FRCC	—	—	11,824	13,254	16,591
MAAC	23,870	23,892	24,019	24,360	25,079
MAIN	447	468	971	3,348	2,161
MAPP(U.S.)	585	706	1,053	1,863	2,834
NPCC(U.S.)	57,511	56,207	58,858	63,557	72,241
SERC	29,184	31,276	15,324	17,289	20,432
SPP	5,345	6,090	5,130	484	4,527
WSCC(U.S.)	65,842	67,028	80,502	89,372	130,866
Contiguous U.S.	**218,567**	**225,445**	**239,577**	**254,779**	**312,003**
ASCC	7	5	10	317	366
Hawaii	3,518	3,568	3,625	3,437	3,387
U.S. Total	**222,092**	**229,018**	**243,213**	**258,534**	**315,757**

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

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

Table 40. Net Internal Demand, Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region and Hawaii, 2000 Through 2004
(Megawatts)

North American Electric Reliability Council Region and Hawaii	2000			2001		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	94,072	107,451	12.5	95,914	108,641	11.7
ERCOT	51,697	65,423	21.0	53,414	69,769	23.4
FRCC	34,832	40,645	14.3	35,560	42,840	17.0
MAAC	49,325	57,831	14.7	49,884	59,805	16.6
MAIN	47,165	55,984	15.8	48,020	59,509	19.3
MAPP(U.S)	30,606	35,373	13.5	31,026	35,064	11.5
NPCC(U.S)	53,450	63,077	15.3	54,170	66,687	18.8
SERC	142,725	160,780	11.2	148,200	164,520	9.9
SPP	37,807	43,111	12.3	38,631	45,157	14.5
WSCC(U.S)	112,177	136,274	17.7	114,830	141,068	18.6
Contiguous U.S	**653,856**	**765,949**	**14.6**	**669,649**	**793,060**	**15.6**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**653,856**	**765,949**	**14.6**	**669,649**	**793,060**	**15.6**

	2002			2004		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	97,473	109,880	11.3	101,230	114,862	11.9
ERCOT	54,952	71,646	23.3	57,932	71,978	19.5
FRCC	36,432	43,734	16.7	38,164	46,652	18.2
MAAC	50,630	64,621	21.7	52,406	74,496	29.7
MAIN	48,803	60,941	19.9	50,567	62,530	19.1
MAPP(U.S)	31,162	34,923	10.8	31,488	35,399	11.0
NPCC(U.S)	54,836	77,324	29.1	56,205	79,967	29.7
SERC	152,007	169,685	10.4	158,441	179,345	11.7
SPP	39,503	46,089	14.3	41,056	46,966	12.6
WSCC(U.S)	117,166	150,024	21.9	122,151	157,805	22.6
Contiguous U.S	**682,964**	**828,867**	**17.6**	**709,640**	**870,000**	**18.4**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**682,964**	**828,867**	**17.6**	**709,640**	**870,000**	**18.4**

	2000			2001		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Winter					
ECAR	83,331	108,339	23.1	84,672	108,392	21.9
ERCOT	41,418	67,856	39.0	42,920	70,500	39.1
FRCC	36,814	43,916	16.2	37,753	44,849	15.8
MAAC	42,307	60,815	30.4	42,885	66,458	35.5
MAIN	37,491	55,607	32.6	38,144	60,094	36.5
MAPP(U.S)	26,273	33,770	22.2	26,754	34,093	21.5
NPCC(U.S)	45,170	65,355	30.9	45,610	73,457	37.9
SERC	128,237	163,139	21.4	131,422	168,114	21.8
SPP	27,452	42,651	35.6	28,096	44,795	37.3
WSCC(U.S)	101,096	137,376	26.4	103,500	142,465	27.4
Contiguous U.S	**569,625**	**778,824**	**26.9**	**581,756**	**813,217**	**28.5**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**569,625**	**778,824**	**26.9**	**581,756**	**813,217**	**28.5**

See footnotes at end of table.

Table 40. Net Internal Demand, Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region and Hawaii, 2000 Through 2004 (Continued)

(Megawatts)

North American Electric Reliability Council Region and Hawaii	2002			2004		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Winter					
ECAR	86,198	108,908	20.9	89,193	113,364	21.3
ERCOT	44,049	72,075	38.9	46,696	72,359	35.5
FRCC	38,679	47,434	18.5	40,551	49,267	17.7
MAAC	43,622	74,375	41.3	44,933	79,309	43.3
MAIN	38,795	61,566	37.0	40,155	62,783	36.0
MAPP(U.S)	26,803	34,231	21.7	26,952	34,729	22.4
NPCC(U.S)	46,163	80,510	42.7	47,369	82,193	42.4
SERC	133,711	173,741	23.0	139,007	185,832	25.2
SPP	28,972	45,586	36.4	30,275	46,406	34.8
WSCC(U.S)	105,462	152,355	30.8	109,543	158,713	31.0
Contiguous U.S	**592,454**	**850,781**	**30.4**	**614,674**	**884,955**	**30.5**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**592,454**	**850,781**	**30.4**	**614,674**	**884,955**	**30.5**

(1) Data for ASCC (Alaska) were not filed.
(2) Data for Hawaii are not submitted on this form.
Notes: •Data are projected and updated annually. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding. •Represents an hour of a day during the associated peak period. •The summer peak period begins on June 1 and extends through September 30. •The winter peak period begins on December 1 and extends through March 31 of the following year. For example, winter 2000 begins December 1, 2000, and extends through March 31, 2001. Thus, the winter referred to here would be the winter of 2000/2001.
Source: Form EIA-411, ''Coordinated Bulk Power Supply Program''.

Table 41. Net Imports at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1995	1996	1997	1998	1999
ECAR	5,759,606	1,906,706	1,379,798	–1,533,577	–219,085
ERCOT	–925,370	–1,024,062	–577,345	–288,303	–949,077
FRCC	–-	–-	–-	–-	–-
MAAC	15,725	199,333	113,318	–163,858	–16,410
MAIN	450	163,471	879,588	806,805	402,770
MAPP(U.S.)	9,171,991	9,705,026	10,251,395	7,724,305	6,050,410
NPCC(U.S.)	23,067,556	20,428,597	15,917,517	15,665,514	20,240,026
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	350	3,700	–6,875
WSCC(U.S.)	2,139,805	8,814,286	6,090,941	4,567,857	3,490,196
Contiguous U.S.	**39,229,763**	**40,193,357**	**34,055,562**	**26,782,443**	**28,991,955**
ASCC	1,102	1,185	1,629	992	1,413
Hawaii[1]	–-	–-	–-	–-	–-
U.S. Total	**39,230,865**	**40,194,542**	**34,057,191**	**26,783,435**	**28,993,368**
Net Canada	38,127,875	40,247,015	35,538,169	27,818,833	29,957,820
Net Mexico	1,102,990	–52,473	–1,480,978	–1,035,398	–964,452

1 Data for Hawaii are not submitted on this form.
Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •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.
•Sources: Canada: National Energy Board of Canada; Mexico: Office of Fuels Programs, Fossil Energy, Form FE-781R, ''Annual Report of International Electric Export/Import Data.''

Table 42. Imports to U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1995	1996	1997	1998	1999
ECAR	5,800,588	2,125,829	3,384,292	2,027,472	889,216
ERCOT	–-	5,566	526,185	738,369	204,136
FRCC	–-	–-	–-	–-	–-
MAAC	22,625	207,183	113,818	10,965	13,350
MAIN	450	163,471	879,588	840,607	406,140
MAPP(U.S.)	9,374,324	10,019,894	10,523,784	9,337,540	7,647,786
NPCC(U.S.)	23,636,732	21,209,207	17,540,075	17,446,689	23,181,052
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	350	3,700	875
WSCC(U.S.)	4,017,709	9,764,193	10,061,509	9,107,024	10,871,142
Contiguous U.S.	**42,852,428**	**43,495,343**	**43,029,601**	**39,512,366**	**43,213,697**
ASCC	1,102	1,185	1,629	992	1,413
Hawaii[1]	–-	–-	–-	–-	–-
U.S. Total	**42,853,530**	**43,496,528**	**43,031,230**	**39,513,358**	**43,215,110**
From Canada	40,596,119	42,233,376	43,008,501	39,502,108	42,911,308
From Mexico	2,257,411	1,263,152	22,729	11,249	303,802

1 Data for Hawaii are not submitted on this form.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •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.

•Sources: Canada: National Energy Board of Canada; Mexico: Office of Fuels Programs, Fossil Energy, Form FE-781R, ‘‘Annual Report of International Electric Export/Import Data.’’

Table 43. Exports from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1995	1996	1997	1998	1999
ECAR	40,982	219,123	2,004,494	3,561,049	1,108,301
ERCOT	925,370	1,029,628	1,103,530	1,026,672	1,153,213
FRCC	–-	–-	–-	–-	–-
MAAC	6,900	7,850	500	174,823	29,760
MAIN	0	–-	–-	33,802	3,370
MAPP(U.S.)	202,333	314,868	272,389	1,613,235	1,597,376
NPCC(U.S.)	569,176	780,610	1,622,558	1,781,175	2,941,026
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	–-	–-	7,750
WSCC(U.S.)	1,877,904	949,907	3,970,568	4,539,167	7,380,946
Contiguous U.S.	**3,622,665**	**3,301,986**	**8,974,039**	**12,729,923**	**14,221,742**
ASCC	–-	–-	–-	–-	0
Hawaii[1]	–-	–-	–-	–-	–-
U.S. Total	**3,622,665**	**3,301,986**	**8,974,039**	**12,729,923**	**14,221,742**
To Canada	2,468,244	1,986,361	7,470,332	11,683,276	12,953,488
To Mexico	1,154,421	1,315,625	1,503,707	1,046,647	1,268,254

1 Data for Hawaii are not submitted on this form.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •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.

•Sources: Canada: National Energy Board of Canada; Mexico: Office of Fuels Programs, Fossil Energy, Form FE-781R, ‘‘Annual Report of International Electric Export/Import Data.’’

U.S. Electric Utility Demand-Side Management

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

Background

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

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

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

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

Identify Program Alternatives

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

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

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

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

Planning and Selection of Programs

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

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

However, traditional costs seldom reflect the full cost to society of utility activities that adversely affect the environment. In assessing supply-side and demand-side options for planning purposes, regulators have been moving to consider broad impacts of utility resource acquisition on society, including environmental and other externalities. Environmental externalities are real impacts on the production or utility functions of others, including impacts on health and property values which are not reflected in the prices of goods and services.[11] Under traditional command-and-control air quality regulation, the additional emissions associated with operating a polluting facility for more hours do not increase the production costs of the source. Thus, many residual air emissions are classified as externalities. Externalities also may include foreign oil or transition costs associated with local economic dislocations. Environmental externalities have become a part of the criteria for comparison and selection of utility resource options in 26 States and the District of Columbia.[12]

Data Sources

The data in the following tables were collected on Schedule V, “Demand-Side Management Information” of the 1999 Form EIA-861,“Annual Electric Utility Report.” Schedule V collects utility information on actual and potential peak load reductions and energy savings for two program categories: Energy Efficiency and Load Management programs, by four major consumer sectors (residential, commercial, industrial, and other). Utilities provide information for the reporting year 1999.

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

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

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

Why the Numbers are Changing

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

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

Reminder: It is no longer possible to directly compare 1998 and 1999 with prior years as the threshold for small and large utilities was changed. Small utilities in 1998 and 1999 are classified as having sales for resales, and sales to ultimate consumers of less than 150 million kilowatthours. For 1997 and prior years, small utilities were classified as having sales for resale and sales to ultimate consumers of less than 120 million kilowatthours.

Table 44. U.S. Electric Utility Demand-Side Management Program Energy Savings, Actual and Potential Peak Load Reductions, and Cost, 1995 Through 1999

Item	1995	1996	1997	1998	1999
Energy Savings (million kilowatthours)[1]	57,421	61,842	56,406	49,167	50,563
Actual Peak Load Reductions (megawatts)[1] [2]	29,561	29,893	25,284	27,231	26,455
Potential Peak Load Reductions (megawatts)[1]	47,029	48,344	41,237	41,430	43,570
Cost (thousand dollars)[3]	2,421,261	1,902,197	1,636,020	1,420,920	1,423,644

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

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

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

Notes: •Data are final. •Data for 1998 and 1999 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours, and for prior years greater than or equal to 120 million kilowatthours.

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

Table 45. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1995 Through 1999

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Total Actual Peak Load Reduction	Direct Load Control	Interruptible Load	Energy Efficiency	Other Load Management	Other Demand-Side Management
			1995			
ECAR	2,458	364	1,088	839	107	60
ERCOT	1,873	22	94	1,447	306	4
FRCC	—	—	—	—	—	—
MAAC	2,110	311	752	671	362	13
MAIN	1,254	26	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	744	150	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**	**5,352**	**8,401**	**13,212**	**2,168**	**426**
			1996			
ECAR	2,547	398	1,129	852	103	64
ERCOT	2,002	27	91	1,571	309	4
FRCC	—	—	—	—	—	—
MAAC	1,773	230	167	936	426	15
MAIN	1,625	42	790	697	84	12
MAPP(U.S.)	3,106	1,205	853	797	235	15
NPCC(U.S.)	2,554	79	230	2,219	18	9
SERC	10,203	3,221	2,793	3,468	508	212
SPP	924	165	387	176	182	13
WSCC(U.S.)	5,134	206	945	3,517	405	62
Contiguous U.S.	**29,869**	**5,573**	**7,387**	**14,233**	**2,270**	**405**
ASCC	7	3	3	2	0	0
Hawaii	17	0	0	8	8	1
U.S. Total	**29,893**	**5,575**	**7,390**	**14,243**	**2,278**	**407**

See footnotes at end of table.

Table 45. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1995 Through 1999 (Continued)

(Megawatts)

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

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Data for 1998 and 1999 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours, and for prior years greater than or equal to 120 million kilowatthours. •These data reflect actual real changes in the demand for electricity at the time of annual peak load, as opposed to the installed peak load reduction capability (i.e., potential peak load reduction), achieved by all program participants during the reporting year.

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

Table 46. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Program Category, 1999

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]	13,452	13,452	49,691
Load Management[3]	13,003	30,118	872
U.S. Total	**26,455**	**43,570**	**50,563**
	Incremental Effects[6]		
Large Utilities[4]			
Energy Efficiency[5]	695	695	3,027
Load Management[3]	1,568	6,457	67
Total	**2,262**	**7,151**	**3,094**
Small Utilities[7]			
Energy Efficiency[5]	22	22	8
Load Management[3]	54	84	2
Total	**76**	**106**	**9**
U.S. Total	**2,338**	**7,258**	**3,103**

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

2 Represents the potential peak load reduction as a result of load management, and also includes the actual peak load reduction achieved by energy efficiency programs.

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

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

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

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

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

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

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

Table 47. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Sector, 1999

Sector	Actual Peak Load Reductions[1] (megawatts)	Potential Peak Load Reductions[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Residential	9,976	12,812	16,263
Commercial	7,777	8,868	23,375
Industrial	6,360	17,237	8,156
Other	2,342	4,653	2,770
U.S. Total	**26,455**	**43,570**	**50,563**
	Incremental Effects[3]		
Large Utilities[4]			
Residential	605	753	990
Commercial	684	718	1,502
Industrial	929	5,612	475
Other	45	68	127
Total	**2,263**	**7,151**	**3,094**
Small Utilities[5]			
Residential	27	41	4
Commercial	22	25	3
Industrial	7	9	1
Other	19	31	1
Total	**76**	**106**	**9**
U.S. Total	**2,338**	**7,258**	**3,103**

1 Represents the reduction in annual peak load achieved by consumers, at the time of annual peak load .
2 Represents the potential peak load reduction as a result of load management, and also includes the actual peak load reduction achieved by energy efficiency programs.
3 Represents the total effects caused by all participants in demand-side management programs in effect during 1999. Included are new and existing participants in existing programs (those implemented in prior years that were in place during 1999) and all participants in new programs (those implemented during 1999).
4 Refers to electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours.
5 Refers to electric utilities with sales to ultimate consumers and sales for resale less than 150 million kilowatthours.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 48. U.S. Electric Utility Demand-Side Management Energy Savings by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Historical Savings				
	1995	1996	1997	1998	1999
ECAR	3,030	3,695	1.984	2.311	2,199
ERCOT	3,757	3,866	3,530	3,690	3,875
FRCC	–-	–-	5,418	5,839	6,143
MAAC	3,000	3,620	4,003	4,531	4,780
MAIN	2,732	3,007	1,429	3,233	3,046
MAPP(U.S.)	2,506	3,153	3,442	3,546	4,548
NPCC(U.S.)	9,694	10,022	9,125	6,928	4,131
SERC	10,143	10,404	4,588	4,148	3,157
SPP	335	358	253	240	198
WSCC(U.S.)	22,178	23,663	22,570	14,575	18,374
Contiguous U.S.	**57,374**	**61,789**	**56,342**	**49,041**	**50,451**
ASCC	4	5	9	7	7
Hawaii	43	49	55	119	105
U.S. Total	**57,421**	**61,842**	**56,406**	**49,167**	**50,563**

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •On January 1, 1997, FRCC became the tenth NERC region, separating from SERC. •Totals may not equal sum of components because of independent rounding. •Data for 1998 and 1999 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150 million kilowatthours, and for prior years greater than or equal to 120 million kilowatthours.
Source: Energy Information Administration, Form EIA-861, ''Annual Electric Utility Report.''

Table 49. U.S. Electric Utility Demand-Side Management Cost by North American Electric Reliability Council Region and Hawaii, 1995 Through 1999

(Thousand Dollars)

North American Electric Reliability Council Region and Hawaii	Existing				
	1995	1996	1997	1998	1999
ECAR	138,910	77,031	37,270	28,406	26,274
ERCOT	70,421	54,120	41,839	30,158	28,022
FRCC	–-	–-	267,738	268,565	249,759
MAAC	300,347	225,253	184,125	207,803	184,094
MAIN	78,004	70,350	50,513	77,361	105,596
MAPP(U.S.)	158,971	156,688	125,804	129,462	120,772
NPCC(U.S.)	346,716	263,160	272,144	185,970	149,552
SERC	681,161	551,038	245,385	175,585	158,993
SPP	26,523	28,385	18,751	33,289	5,630
WSCC(U.S.)	619,575	471,759	384,197	273,095	385,854
Contiguous U.S.	**2,420,628**	**1,897,782**	**1,627,766**	**1,409,694**	**1,414,546**
ASCC	633	291	322	319	355
Hawaii	0	4,124	7,932	10,907	8,743
Total Cost[1]	**2,421,261**	**1,902,197**	**1,636,020**	**1,420,920**	**1,423,644**

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

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

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

Table 50. U.S. Electric Utility Demand-Side Management Direct and Indirect Cost, 1998 and 1999

(Thousand Dollars)

Program	1998	1999
Total Direct Cost[1]	**1,233,018**	**1,250,689**
Energy Efficiency	766,384	820,108
Load Management	466,634	430,581
Indirect Utility Cost[2]	**187,902**	**172,955**
Cost (thousand dollars)	**1,420,920**	**1,423,644**

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

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

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

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

U.S. Nonutility Power Producers

This chapter provides an overview of U.S. nonutility power producers, and their generating technologies, together with statistical data on capacity, generation, sales, consumption and emissions for 1995 through 1999. These data are aggregated at the U.S. Census division level. Since nonutility data for 1995 through 1997 are confidential, the EIA implemented information disclosure rules. (See “Nondisclosure of Data” in Appendix A.)

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

Background

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

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

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

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

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

Under FERC rules, cogeneration and small power production facilities may be designated as QF's if they meet specific ownership,[13] operating, and efficiency criteria. A facility may file an information report, known as a “self qualifying notice,” with the FERC if it meets the requirements of FERC published rules, or it may apply to the FERC for certification as a QF under PURPA. QF's are guaranteed that electric utilities will purchase their output at the utilities' avoided cost, which is the incremental cost that an electric utility would incur to produce or purchase an amount of power equivalent to that purchased from QF's. Additionally, QF's are guaranteed that electric utilities will provide back up service at prevailing (non discriminatory) rates.

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

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

The growth of nonutilities was further advanced by the Energy Policy Act of 1992 (EPACT). EPACT expanded the nonutility markets by creating a new category of power producers called exempt wholesale generators (EWG), which are exempt from the corporate and geographic restrictions imposed by the Public Utility Holding Company Act of 1935 (PUHCA).[14] EWG's are defined as businesses that own and/or operate a facility exclusively for the generation of electric energy for sale at wholesale. Exempting EWG's from PUHCA regulation removed obstacles to wholesale power competition by allowing utilities and nonutilities to form EWG's without triggering the restrictions of PUHCA. EWG's differ from QF's in several ways. They are not required to meet PURPA's cogeneration or renewable fuels limitations, utilities are not required to purchase their power, and they may charge market-based rates.

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

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

Nonutility Classifications

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

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

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

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

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

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

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

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

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

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

Nonutility Operations

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

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

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

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

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

Data Sources

Summary statistics on nonutility capacity, generation, sales, consumption, and emissions in the United States are provided in the following tables. Data for 1995 through 1999 are final. These data were obtained from the Form EIA-860B, "Annual Electric Generator Report - Nonutility" (prior Form EIA-867, "Annual Nonutility Power Producer Report.") The Form EIA-860B is a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered from 5 megawatts to 1 megawatt to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected from facilities with a nameplate capacity between 1 and 5 megawatts every 3 years. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure of the facility. Nonutilities generally install small, turn-key packaged generating facilities with minimal regulatory requirements which result in considerably less lead time to finance and build, as compared to traditional electric utility facilities.

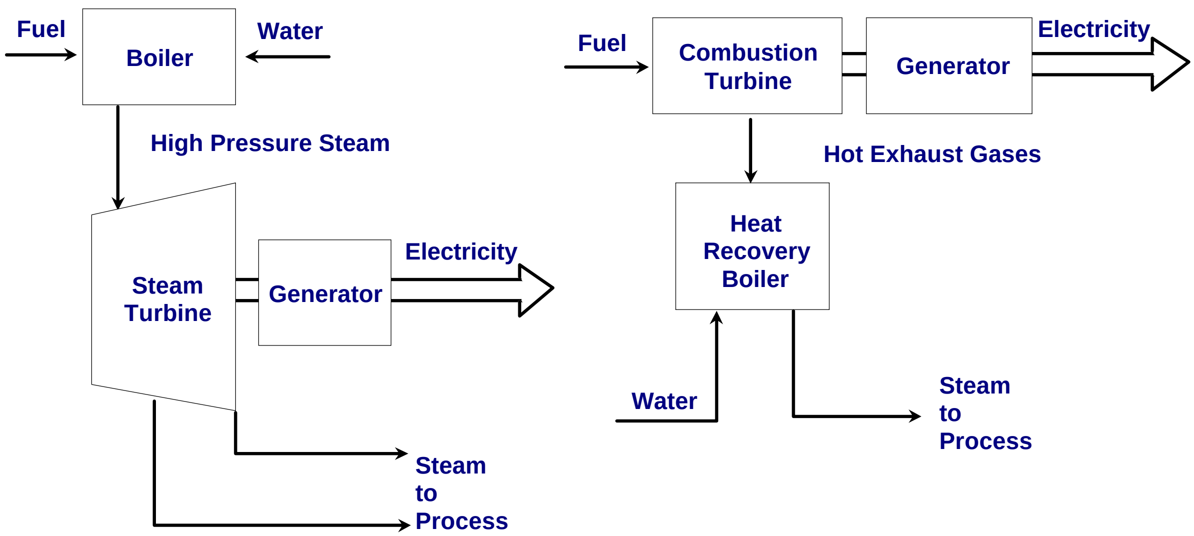
Some nonutility power producers of 1 or more megawatts use only fossil fuels; some use only renewable energy; and some use a combination of both fossil fuels and renewable energy sources. Although the majority of nonutility power producers generate electric power using fossil energy, those using renewable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

The other energy sources in Tables 51, 53, 54, 57, and 58 include hydrogen, sulfur, batteries, chemicals, and purchased steam.

The number of facilities shown for 1999 includes operational facilities in 1998 and new facilities or planned facilities that became operational during that year.

The total capacity for 1995 through 1999 (Table 51) includes all operable generating units including units not normally used but on standby with little or no generation, and units out of service for the entire reporting year that are expected to be returned to service in the future. Units on standby, test, maintenance/repairs, out of service, and indefinite shutdown represented 43 percent of the total nonutility generating capacity in 1999.

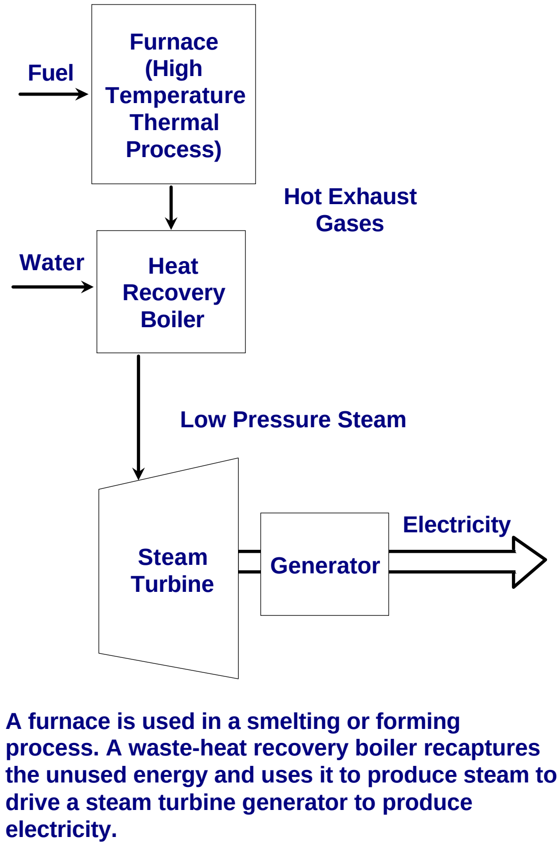
Figure 10. Two Topping-Cycle Plant Configurations



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

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

Figure 11. Bottoming-Cycle Plant Configuration



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

Table 51. Summary Statistics for U.S. Nonutility Generating Facilities, 1995 Through 1999

Item	1995	1996	1997	1998	1999
Installed Capacity (megawatts)	**70,254**	**73,189**	**74,004**	**98,085**	**167,357**
Coal[1]	10,877	11,370	11,027	13,712	48,501
Petroleum[2]	2,116	2,251	2,924	2,629	3,701
Natural Gas[3]	27,906	30,166	31,092	37,325	49,353
Other Gas[4]	1,217	327	35	205	918
Petroleum/Natural Gas (Combined)	10,479	10,912	10,029	23,105	40,508
Hydroelectric	3,399	3,419	3,770	4,136	5,996
Geothermal	1,295	1,346	1,303	1,449	2,698
Solar	354	354	354	385	382
Wind	1,723	1,670	1,566	1,689	2,222
Wood[5]	6,885	7,263	7,282	6,887	6,647
Waste[6]	3,430	3,463	3,394	3,488	4,316
Nuclear	—	—	—	—	1,542
Other[7]	574	648	1,229	3,075	574
Gross Generation (million kilowatthours)	**375,901**	**382,423**	**384,496**	**421,364**	**569,336**
Coal[1]	60,234	61,375	59,211	70,369	129,502
Petroleum[2]	15,049	14,959	15,930	17,533	21,947
Natural Gas[3]	196,633	198,555	207,527	238,747	295,725
Other Gas[4]	13,984	14,750	11,687	8,866	8,707
Hydroelectric	14,774	16,555	17,902	14,633	21,748
Geothermal	9,912	10,198	9,382	9,882	15,581
Solar	824	903	893	887	870
Wind	3,185	3,400	3,248	3,015	4,510
Wood[5]	37,283	37,525	34,898	32,596	34,999
Waste[6]	20,231	20,412	20,246	21,086	22,312
Nuclear	—	—	—	—	9,347
Other[7]	3,792	3,793	3,572	3,750	4,088
Consumption[8]					
Coal (Thousand short tons)	50,328	53,199	52,913	56,850	86,467
Petroleum (Thousand barrels)[9]	R 35,031	R 38,444	R 35,594	R 54,275	74,727
Natural Gas (Million cubic feet)	2,303,944	2,447,720	2,231,363	2,666,430	2,869,740
Other Gas (Million cubic feet)[4]	R 1,604,427	R 1,730,400	R 948,154	R 873,107	659,637
Supply and Disposition (million kilowatthours)					
Gross Generation	375,901	382,423	384,496	421,364	569,336
Receipts[10]	89,919	103,219	88,506	90,675	89,688
Sales to Utilities[11]	217,906	224,646	223,532	249,483	369,539
Sales to Other End Users[12]	15,548	14,284	18,147	25,777	42,983
Facility Use	232,367	246,713	231,138	236,770	250,227

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, liqnite waste, tar coal, and waste coal.
2 Includes petroleum, petroleum coke, diesel, kerosene, light oil, liquid butane, liquid propane, oil waste, sludge oil, and tar oil.
3 Includes natural gas and waste heat.
4 Includes butane, propane, and other gas.
5 Includes black liquor, peat, railroad ties, red liquor, sludge wood, spent sulfite liquor, utility poles, and wood/wood waste.
6 Includes agricultural byproducts, digester gas, fish oil, liquid acetonitrile waste, landfill gas, medical waste, methane, municipal solid waste, paper pellets, sludge waste, solid byproducts, straw, tires, tall oil, and waste alcohol.
7 Includes batteries, chemicals, hydrogen, pitch, purchased steam, and sulfur.
8 Includes all combustible fuels burned at generating facilities (not just for the production of electricity).
9 Does not include petroleum coke consumption of 4,188 thousand short tons for 1995, 4,484 thousand short tons for 1996, 4,364 thousand short tons for 1997, 4,470 thousand short tons for 1998, and 4,332 thousand short tons for 1999.
10 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
11 Includes sales, interchanges, and exchanges of electric energy with utilities.
12 Includes sales, interchanges, and exchanges of electric energy with other nonutilities. The disparity in this data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-860B (prior, Form EIA-867) is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures attribute to the disparity.

R = Revised data.

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

Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B, ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867, ''Annual Nonutility Power Producer Report''.

Table 52. Installed Capacity at U.S. Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Source, and Census Division, 1995 Through 1999
(Megawatts)

Census Division	Fossil Fuels[1]	Renewables/ Other/ Nuclear[2]	Both Fossil Fuels and Renewables/ Other/ Nuclear
		1995	
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	1,413	261	2,217
Mountain	1,890	614	253
Pacific	8,014	5,014	831
U.S. Total	**48,354**	**11,601**	**10,299**
		1996	
New England	2,773	1,233	1,196
Middle Atlantic	11,096	859	1,032
East North Central	4,396	391	1,287
West North Central	912	194	149
South Atlantic	8,831	1,785	3,046
East South Central	438	234	1,495
West South Central	11,919	285	2,230
Mountain	1,962	604	316
Pacific	8,578	4,821	1,128
U.S. Total	**50,905**	**10,406**	**11,879**
		1997	
New England	3,019	1,436	840
Middle Atlantic	11,084	1,389	547
East North Central	4,322	788	1,073
West North Central	1,176	214	220
South Atlantic	8,597	2,471	2,742
East South Central	463	598	1,150
West South Central	10,591	556	3,742
Mountain	1,919	644	305
Pacific	8,647	4,465	1,005
U.S. Total	**49,820**	**12,561**	**11,624**
		1998	
New England	8,428	2,042	1,348
Middle Atlantic	10,726	854	1,226
East North Central	6,417	359	1,431
West North Central	1,199	250	237
South Atlantic	8,375	1,468	3,807
East South Central	2,705	238	1,430
West South Central	12,827	652	2,394
Mountain	2,032	563	291
Pacific	19,755	5,576	1,454
U.S. Total	**72,465**	**12,002**	**13,619**
		1999	
New England	14,837	4,338	309
Middle Atlantic	31,023	3,057	756
East North Central	13,201	1,552	15,938
West North Central	3,043	754	99
South Atlantic	9,447	3,967	1,002
East South Central	4,355	1,231	423
West South Central	14,245	1,409	2,274
Mountain	5,548	1,289	5
Pacific	26,105	6,779	369
U.S. Total	**121,806**	**24,376**	**21,175**

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

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

Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 53. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1995 Through 1999

(Megawatts)

Census Division	Coal[1]	Natural Gas/ Other Gas[2]	Petroleum[3] only / and Natural Gas[4]	Hydroelectric/ Geothermal/ Solar / Wind	Wood[5] / Waste[6]	Other[7] / Nuclear	Total
				1995			
New England	353	1,118	1,579	584	1,404	--	5,037
Middle Atlantic	2,590	4,713	W	485	913	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	10,808	887	W	1,145	W	13,891
Mountain	W	1,294	447	560	153	W	2,757
Pacific	W	6,122	1,387	4,012	1,571	W	13,860
U.S. Total	**10,877**	**29,122**	**12,595**	**6,771**	**10,316**	**574**	**70,254**
				1996			
New England	441	925	W	589	1,436	W	5,202
Middle Atlantic	2,554	4,947	4,083	485	919	--	12,987
East North Central	1,792	W	583	105	730	W	6,074
West North Central	741	63	172	103	175	--	1,255
South Atlantic	3,694	2,255	3,549	568	3,257	340	13,662
East South Central	324	197	W	W	1,328	W	2,167
West South Central	839	W	1,011	W	1,117	81	14,433
Mountain	239	W	513	560	150	W	2,881
Pacific	748	6,715	1,379	3,978	1,614	93	14,527
U.S. Total	**11,370**	**30,493**	**13,163**	**6,788**	**10,726**	**648**	**73,189**
				1997			
New England	353	966	1,961	599	1,301	114	5,295
Middle Atlantic	2,583	4,930	3,888	526	1,018	74	13,020
East North Central	1,596	W	481	W	918	171	6,183
West North Central	W	W	373	111	213	W	1,611
South Atlantic	3,621	2,345	3,277	1,036	3,160	371	13,810
East South Central	309	192	156	W	1,292	W	2,212
West South Central	829	11,187	1,225	372	1,119	158	14,890
Mountain	W	W	487	534	150	83	2,868
Pacific	741	7,076	1,104	3,506	1,505	185	14,117
U.S. Total	**11,027**	**31,127**	**12,953**	**6,993**	**10,676**	**1,229**	**74,004**
				1998			
New England	1,321	1,095	6,339	1,645	1,408	9	11,818
Middle Atlantic	2,136	5,229	3,863	449	882	248	12,806
East North Central	3,044	2,986	1,117	98	870	93	8,207
West North Central	682	167	421	202	203	11	1,686
South Atlantic	3,424	1,360	4,410	530	3,076	850	13,650
East South Central	1,839	279	829	172	1,209	46	4,373
West South Central	466	11,423	2,194	227	1,063	500	15,873
Mountain	197	1,305	656	520	150	58	2,887
Pacific	605	13,685	5,905	3,816	1,513	1,261	26,785
U.S. Total	**13,712**	**37,530**	**25,734**	**7,659**	**10,374**	**3,075**	**98,085**
				1999			
New England	2,864	1,786	10,496	2,082	1,583	673	19,484
Middle Atlantic	12,735	4,332	14,713	1,170	1,015	872	34,837
East North Central	19,314	8,477	1,349	101	1,451	—	30,691
West North Central	2,643	348	152	532	222	—	3,896
South Atlantic	4,032	1,449	4,968	598	2,986	384	14,416
East South Central	2,397	2,136	244	175	1,016	40	6,009
West South Central	827	13,925	1,768	368	931	111	17,929
Mountain	2,899	2,133	521	1,103	159	27	6,842
Pacific	790	15,685	9,999	5,169	1,601	9	33,254
U.S. Total	**48,501**	**50,271**	**44,209**	**11,298**	**10,963**	**2,116**	**167,357**

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

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

Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 54. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and State, 1999
(Megawatts)

State	Coal[1]	Natural Gas/ Other Gas[2]	Petroleum[3] only / and Natural Gas[4]	Hydroelectric/ Geothermal/ Solar / Wind	Wood[5] / Waste[6]	Other[7] / Nuclear	Total
Alabama	56	369	146	—	712	—	1,283
Alaska	90	153	68	—	—	—	310
Arizona	71	68	47	—	—	—	186
Arkansas	—	24	125	1	268	—	418
California	407	14,523	9,304	4,868	1,078	9	30,189
Colorado	35	770	36	32	5	—	878
Connecticut	721	520	2,843	20	262	3	4,369
Delaware	30	1	140	—	—	—	171
Florida	857	802	1,644	—	1,075	344	4,721
Georgia	148	43	885	12	735	—	1,824
Hawaii	268	9	320	69	116	—	782
Idaho	20	21	—	255	140	16	451
Illinois	17,639	5,014	428	21	911	—	24,013
Indiana	597	866	280	—	18	—	1,761
Iowa	319	—	73	198	10	—	601
Kansas	—	44	7	3	—	—	53
Kentucky	1,950	—	65	—	4	—	2,019
Louisiana	—	3,301	240	192	474	22	4,230
Maine	102	—	1,258	754	810	—	2,924
Maryland	265	152	380	19	77	—	893
Massachusetts	2,041	1,266	5,268	722	330	670	10,297
Michigan	389	2,476	91	27	432	—	3,415
Minnesota	2,196	299	50	331	198	—	3,074
Mississippi	—	1,136	34	4	279	—	1,452
Missouri	100	4	9	—	—	—	114
Montana	2,380	—	65	588	11	—	3,043
Nebraska	8	2	5	—	4	—	18
Nevada	306	1,041	210	217	—	—	1,774
New Hampshire	—	—	34	397	139	—	571
New Jersey	515	1,022	3,336	13	211	—	5,097
New Mexico	—	120	140	—	2	—	262
New York	2,854	2,652	10,222	1,040	488	—	17,256
North Carolina	997	203	89	374	204	40	1,907
North Dakota	19	—	8	—	10	—	37
Ohio	209	100	6	—	16	—	331
Oklahoma	464	310	51	—	80	—	905
Oregon	14	640	57	126	140	—	977
Pennsylvania	9,366	657	1,155	117	316	872	12,483
Rhode Island	—	—	1,092	3	15	—	1,110
South Carolina	140	118	6	27	217	—	508
South Dakota	–-	–-	–-	–-	–-	–-	–-
Tennessee	391	631	—	172	21	40	1,255
Texas	363	10,289	1,351	175	109	89	12,376
Utah	58	54	20	4	2	—	137
Vermont	—	—	—	187	26	—	213
Virginia	1,182	105	1,812	21	677	—	3,797
Washington	12	361	251	105	268	—	997
West Virginia	414	25	12	144	—	—	595
Wisconsin	481	21	544	53	73	—	1,171
Wyoming	30	59	4	7	—	12	111
U.S. Total	**48,501**	**50,271**	**44,209**	**11,298**	**10,963**	**2,116**	**167,357**

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

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

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

Table 55. Installed Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1995 Through 1999

(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)
			1995			
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**
			1996			
New England	119	3,625	76	1,577	195	5,202
Middle Atlantic	259	12,604	45	383	304	12,987
East North Central	113	3,758	116	2,316	229	6,074
West North Central	28	576	54	679	82	1,255
South Atlantic	165	9,728	123	3,934	288	13,662
East South Central	27	1,214	32	954	59	2,167
West South Central	111	12,696	62	1,737	173	14,433
Mountain	90	2,102	40	779	130	2,881
Pacific	401	12,042	134	2,485	535	14,527
U.S. Total	**1,313**	**58,345**	**682**	**14,844**	**1,995**	**73,189**
			1997			
New England	121	3,707	79	1,588	200	5,295
Middle Atlantic	257	12,628	45	392	302	13,020
East North Central	120	3,909	110	2,273	230	6,183
West North Central	29	931	56	680	85	1,611
South Atlantic	171	9,897	120	3,913	291	13,810
East South Central	29	1,237	32	975	61	2,212
West South Central	111	13,050	66	1,839	177	14,890
Mountain	88	2,086	39	782	127	2,868
Pacific	376	11,671	125	2,446	501	14,117
U.S. Total	**1,302**	**59,116**	**672**	**14,888**	**1,974**	**74,004**
			1998			
New England	122	3,624	100	8,193	222	11,818
Middle Atlantic	252	12,263	44	543	296	12,806
East North Central	125	4,280	114	3,927	239	8,207
West North Central	29	896	57	790	86	1,686
South Atlantic	163	9,771	112	3,879	275	13,650
East South Central	28	1,249	36	3,124	64	4,373
West South Central	114	14,127	64	1,746	178	15,873
Mountain	86	2,101	37	785	123	2,887
Pacific	394	12,072	135	14,713	529	26,785
U.S. Total	**1,313**	**60,384**	**699**	**37,701**	**2,012**	**98,085**
			1999			
New England	122	3,729	158	15,755	280	19,484
Middle Atlantic	239	11,770	160	23,066	399	34,837
East North Central	118	4,348	139	26,344	257	30,691
West North Central	28	896	63	3,000	91	3,896
South Atlantic	163	10,042	112	4,374	275	14,416
East South Central	28	1,278	41	4,731	69	6,009
West South Central	118	15,205	67	2,723	185	17,929
Mountain	85	2,122	57	4,720	142	6,842
Pacific	379	11,881	150	21,373	529	33,254
U.S. Total	**1,280**	**61,270**	**947**	**106,087**	**2,227**	**167,357**

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

Non-QF = Cogenerator and other nonutility generator.

Notes: •All data are for 1 megawatt and greater. •Data are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 56. Installed Capacity at U.S. Nonutility Generating Facilities Attributed to Major Industry Group and Census Division, 1995 through 1999

(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1995			
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	98	164	W	W	W	1,232
South Atlantic	8,842	3,691	169	W	W	218	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**	**15,124**	**2,165**	**3,428**	**544**	**1,388**	**70,254**
				1996			
New England	W	2,391	154	--	--	W	5,202
Middle Atlantic	W	2,400	562	W	221	225	12,987
East North Central	5,172	459	358	W	W	W	6,074
West North Central	762	112	168	W	--	W	1,255
South Atlantic	W	3,763	165	W	64	461	13,662
East South Central	2,104	22	W	26	W	--	2,167
West South Central	13,409	743	197	72	W	W	14,433
Mountain	W	913	W	242	--	667	2,881
Pacific	5,930	5,247	436	2,498	241	176	14,527
U.S. Total	**49,529**	**16,050**	**2,181**	**3,313**	**542**	**1,575**	**73,189**
				1997			
New England	W	2,440	148	--	--	W	5,295
Middle Atlantic	W	2,596	565	W	221	225	13,020
East North Central	5,149	548	398	W	W	W	6,183
West North Central	1,103	127	168	W	--	W	1,611
South Atlantic	W	4,259	168	W	139	404	13,810
East South Central	2,089	76	W	26	W	--	2,212
West South Central	13,886	726	197	68	W	W	14,890
Mountain	W	910	W	239	--	667	2,868
Pacific	5,910	4,876	433	2,498	238	161	14,117
U.S. Total	**49,791**	**16,559**	**2,223**	**3,306**	**616**	**1,510**	**74,004**
				1998			
New England	2,635	5,072	139	--	--	3,972	11,818
Middle Atlantic	9,390	2,203	570	205	221	218	12,806
East North Central	5,040	2,466	678	--	5	18	8,207
West North Central	1,077	219	172	203	--	15	1,686
South Atlantic	9,329	3,604	169	6	63	480	13,650
East South Central	2,149	2,176	14	24	11	--	4,373
West South Central	14,636	959	197	66	1	14	15,873
Mountain	943	952	133	240	--	620	2,887
Pacific	6,057	6,875	435	2,531	234	10,653	26,785
U.S. Total	**51,255**	**24,527**	**2,506**	**3,275**	**534**	**15,989**	**98,085**
				1999			
New England	2,746	7,755	143	—	—	8,840	19,484
Middle Atlantic	9,389	19,813	564	207	220	4,644	34,837
East North Central	5,392	24,380	605	—	3	312	30,691
West North Central	1,136	524	172	2,025	—	38	3,896
South Atlantic	9,072	4,008	171	6	63	1,096	14,416
East South Central	2,004	2,320	14	26	11	1,634	6,009
West South Central	15,697	2,048	88	72	—	25	17,929
Mountain	932	4,400	162	242	—	1,106	6,842
Pacific	6,062	13,172	424	2,544	240	10,812	33,254
U.S. Total	**52,430**	**78,419**	**2,342**	**5,123**	**536**	**28,506**	**167,357**

W = Withheld to avoid disclosure of individual company data.

Notes: •All data are for 1 megawatt and greater. •Data are final. •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 57. Gross Generation for U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1995 Through 1999
(Million Kilowatthours)

Census Division	Coal[1]	Petroleum[2]	Natural Gas/ Other Gas[3]	Hydro-electric	Geothermal/ Solar/Wind	Wood[4] / Waste[5]	Other[6] / Nuclear	Total
				1995				
New England	2,404	1,860	13,425	2,561	--	9,099	--	29,350
Middle Atlantic	14,799	1,781	45,187	1,584	--	6,227	189	69,768
East North Central	6,795	646	16,187	W	--	4,247	W	28,436
West North Central	2,680	W	707	303	W	908	--	4,702
South Atlantic	18,948	2,736	15,535	2,799	--	15,622	1,985	57,624
East South Central	2,378	125	2,175	W	--	7,033	W	12,708
West South Central	6,314	W	67,102	W	--	5,880	1,122	84,635
Mountain	1,511	179	6,828	1,171	W	745	W	12,263
Pacific	4,404	W	43,471	4,070	12,205	7,754	W	76,415
U.S. Total	**60,234**	**15,049**	**210,617**	**14,774**	**13,921**	**57,514**	**3,792**	**375,901**
				1996				
New England	2,289	1,779	W	3,235	--	9,036	W	29,862
Middle Atlantic	15,569	1,425	W	2,337	--	6,414	W	68,860
East North Central	6,972	812	18,113	525	--	4,630	79	31,130
West North Central	2,503	W	564	382	W	812	W	4,362
South Atlantic	19,429	3,034	15,319	3,042	--	15,959	1,703	58,485
East South Central	2,418	194	2,571	W	--	7,031	W	13,249
West South Central	6,026	3,409	66,115	W	W	5,783	1,598	83,994
Mountain	1,461	W	W	1,280	1,663	668	187	13,480
Pacific	4,708	3,784	46,290	3,878	12,703	7,605	33	79,001
U.S. Total	**61,375**	**14,959**	**213,304**	**16,555**	**14,500**	**57,937**	**3,793**	**382,423**
				1997				
New England	2,463	1,845	W	2,981	--	8,884	W	30,273
Middle Atlantic	14,429	1,530	W	2,163	--	6,105	W	68,518
East North Central	7,308	748	17,906	528	--	4,777	98	31,366
West North Central	2,983	W	455	W	W	833	W	4,807
South Atlantic	17,724	3,757	12,369	3,566	916	15,550	1,673	55,555
East South Central	2,300	170	3,059	W	--	5,605	W	12,860
West South Central	6,150	3,572	W	2,109	W	5,626	679	91,270
Mountain	1,507	W	W	1,267	1,576	637	255	13,744
Pacific	4,348	3,696	45,986	3,712	10,895	7,128	338	76,103
U.S. Total	**59,211**	**15,930**	**219,215**	**17,902**	**13,523**	**55,144**	**3,572**	**384,496**
				1998				
New England	5,854	4,024	20,133	3,295	--	8,046	--	41,352
Middle Atlantic	14,784	1,213	42,196	1,963	--	6,389	34	66,579
East North Central	9,783	1,125	17,557	438	--	5,391	31	34,325
West North Central	2,812	623	760	292	148	769	1	5,405
South Atlantic	17,727	3,292	13,935	2,618	--	15,440	1,709	54,720
East South Central	6,906	852	3,833	807	--	5,870	104	18,372
West South Central	6,416	2,253	79,793	1,083	81	4,181	1,547	95,354
Mountain	1,807	456	7,988	1,124	1,571	570	173	13,689
Pacific	4,281	3,695	61,418	3,013	11,984	7,025	150	91,567
U.S. Total	**70,369**	**17,533**	**247,613**	**14,633**	**13,784**	**53,682**	**3,750**	**421,364**
				1999				
New England	11,895	5,794	33,870	5,960	90	8,483	2,645	68,738
Middle Atlantic	39,817	2,952	50,398	3,917	—	6,885	6,910	110,879
East North Central	15,391	936	20,751	436	—	5,650	—	43,163
West North Central	2,903	1,026	974	352	819	1,000	—	7,073
South Atlantic	18,203	3,361	14,566	1,982	—	15,487	1,726	55,324
East South Central	14,079	170	4,334	664	—	6,216	121	25,584
West South Central	6,415	3,329	84,462	815	323	4,993	1,839	102,175
Mountain	16,327	742	7,982	5,067	1,481	713	163	32,475
Pacific	4,473	3,637	87,096	2,554	18,249	7,885	31	123,926
U.S. Total	**129,502**	**21,947**	**304,432**	**21,748**	**20,961**	**57,311**	**13,435**	**569,336**

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

W = Withheld to avoid disclosure of individual company data.

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

Sources: Energy Information Administration, Data for 1999 and 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 58. Gross Generation for U.S. Nonutility Generating Facilities by Energy Source and State, 1999
(Million Kilowatthours)

State	Coal[1]	Petroleum[2]	Natural Gas/ Other Gas[3]	Hydro-electric	Geothermal/ Solar/Wind	Wood[4] / Waste[5]	Other[6] / Nuclear	Total
Alaska	392	74	765	—	—	—	—	1,231
Alabama	457	127	2,551	—	—	4,031	—	7,165
Arkansas	61	16	1,131	1	—	1,354	3	2,566
Arizona	334	4	495	—	—	106	—	940
California	2,462	2,147	78,403	1,523	17,933	5,728	31	108,228
Colorado	292	22	2,973	120	—	32	—	3,439
Connecticut	1,595	103	5,083	57	—	1,746	—	8,585
Delaware	78	350	230	—	—	—	—	657
Florida	5,339	540	8,305	—	—	5,696	1,436	21,316
Georgia	1,561	1,527	1,075	29	—	3,137	21	7,349
Hawaii	1,541	1,374	333	100	230	582	—	4,160
Iowa	1,281	9	153	15	328	73	—	1,858
Idaho	75	1	325	997	—	502	86	1,986
Illinois	9,718	396	2,464	91	—	1,134	—	13,802
Indiana	2,491	12	5,367	—	—	126	—	7,996
Kansas	—	3	53	12	—	—	—	69
Kentucky	11,747	25	19	—	—	13	—	11,804
Louisiana	50	1,702	19,335	810	—	2,664	1,324	25,885
Massachusetts	9,781	2,451	20,380	756	—	2,161	2,645	38,175
Maryland	360	19	1,541	2	—	558	—	2,480
Maine	519	751	4,350	3,275	—	3,171	—	12,065
Michigan	1,424	179	11,258	92	—	2,909	—	15,862
Minnesota	1,213	1,000	643	325	491	898	—	4,569
Missouri	276	14	31	—	—	12	—	332
Mississippi	6	3	1,272	6	—	1,495	—	2,781
Montana	12,474	708	55	3,921	—	53	—	17,212
North Carolina	3,964	520	318	1,214	—	1,626	269	7,911
North Dakota	87	—	74	—	—	6	—	166
Nebraska	46	1	20	—	—	12	—	78
New Hampshire	—	61	58	1,083	90	1,087	—	2,378
New Jersey	1,800	473	14,844	17	—	1,434	—	18,568
New Mexico	—	3	934	—	—	11	—	948
Nevada	2,320	1	2,677	21	1,469	—	—	6,488
New York	8,953	1,751	32,004	3,554	—	2,806	—	49,068
Ohio	395	13	470	—	—	656	—	1,535
Oklahoma	3,351	10	1,341	—	—	173	—	4,875
Oregon	26	—	4,138	409	86	467	—	5,126
Pennsylvania	29,065	728	3,549	346	—	2,645	6,910	43,244
Rhode Island	—	2,425	3,999	6	—	117	—	6,547
South Carolina	608	84	740	41	—	1,596	—	3,069
South Dakota	--	--	--	--	--	--	--	--
Tennessee	1,869	15	493	658	—	677	121	3,833
Texas	2,952	1,601	62,656	3	323	802	512	68,850
Utah	588	2	157	9	—	8	—	763
Virginia	3,963	320	2,134	62	—	2,875	—	9,355
Vermont	—	3	—	783	—	203	—	989
Washington	52	42	3,456	522	—	1,107	—	5,181
Wisconsin	1,363	336	1,191	253	—	825	—	3,968
West Virginia	2,330	—	222	634	—	—	—	3,186
Wyoming	244	1	366	—	11	—	76	699
U.S. Total	**129,502**	**21,947**	**304,432**	**21,748**	**20,961**	**57,311**	**13,435**	**569,336**

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

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

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

Table 59. Gross Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1995 Through 1999
(Million Kilowatthours)

Census Division	QF Generation		Non-QF Generation		Total Generation	
	No. of Facilities[1]	Generation (million kilowatthours)	No. of Facilities[1]	Generation (million kilowatthours)	No. of Facilities[1]	Generation (million kilowatthours)
1995						
New England	115	21,681	72	7,669	187	29,350
Middle Atlantic	252	67,661	47	2,107	299	69,768
East North Central	107	19,255	105	9,182	212	28,436
West North Central	28	2,377	52	2,325	80	4,702
South Atlantic	158	44,277	120	13,348	278	57,624
East South Central	28	7,567	31	5,142	59	12,708
West South Central	107	74,579	57	10,056	164	84,635
Mountain	84	10,024	37	2,239	121	12,263
Pacific	391	69,168	136	7,247	527	76,415
U.S. Total	**1,270**	**316,587**	**657**	**59,314**	**1,927**	**375,901**
1996						
New England	112	21,489	75	8,372	187	29,862
Middle Atlantic	255	66,782	44	2,078	299	68,860
East North Central	108	21,747	110	9,383	218	31,130
West North Central	25	2,196	54	2,166	79	4,362
South Atlantic	159	46,234	119	12,252	278	58,485
East South Central	26	7,727	32	5,522	58	13,249
West South Central	110	74,126	60	9,868	170	83,994
Mountain	87	11,007	39	2,473	126	13,480
Pacific	383	69,801	132	9,200	515	79,001
U.S. Total	**1,265**	**321,109**	**665**	**61,314**	**1,930**	**382,423**
1997						
New England	116	21,971	78	8,302	194	30,273
Middle Atlantic	247	66,594	45	1,924	292	68,518
East North Central	108	22,077	102	9,289	210	31,366
West North Central	26	2,256	56	2,551	82	4,807
South Atlantic	164	44,163	111	11,392	275	55,555
East South Central	28	7,891	32	4,969	60	12,860
West South Central	109	81,635	64	9,635	173	91,270
Mountain	83	11,124	37	2,620	120	13,744
Pacific	365	66,681	122	9,423	487	76,103
U.S. Total	**1,246**	**324,392**	**647**	**60,105**	**1,893**	**384,496**
1998						
New England	116	21,843	98	19,508	214	41,352
Middle Atlantic	245	64,138	41	2,441	286	66,579
East North Central	113	22,277	110	12,049	223	34,325
West North Central	27	2,578	57	2,827	84	5,405
South Atlantic	156	43,482	105	11,238	261	54,720
East South Central	27	7,575	36	10,797	63	18,372
West South Central	111	86,181	62	9,173	173	95,354
Mountain	82	11,240	35	2,449	117	13,689
Pacific	379	68,663	132	22,905	511	91,567
U.S. Total	**1,256**	**327,977**	**676**	**93,387**	**1,932**	**421,364**
1999						
New England	117	21,689	151	47,049	268	68,738
Middle Atlantic	237	62,281	151	48,598	388	110,879
East North Central	114	22,550	132	20,613	246	43,163
West North Central	26	3,396	63	3,677	89	7,073
South Atlantic	159	44,868	108	10,457	267	55,324
East South Central	27	7,715	41	17,869	68	25,584
West South Central	117	92,514	64	9,661	181	102,175
Mountain	80	11,195	55	21,280	135	32,475
Pacific	371	68,626	149	55,300	520	123,926
U.S. Total	**1,248**	**334,833**	**914**	**234,503**	**2,162**	**569,336**

[1] The number of facilities with no generation that were not retired were 46 in 1995, 65 in 1996, 81 in 1997, 80 in 1998, and 65 in 1999.

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

Non-QF = Cogenerator and other nonutility generator.

Notes: •All data are for 1 megawatt and greater. •Data are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Data for 1998 and 1999 : Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 60. Gross Generation at U.S. Nonutility Generating Facilities Attributed to Major Industry Group and Census Division, 1995 Through 1999

(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1995			
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	169	57,624
East South Central	12,448	70	W	125	W	--	12,708
West South Central	82,434	W	614	492	--	W	84,635
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	**268,711**	**67,682**	**10,775**	**21,277**	**2,617**	**4,839**	**375,901**
				1996			
New England	W	13,987	640	--	--	W	29,862
Middle Atlantic	W	12,347	3,819	W	1,033	1,621	68,860
East North Central	27,124	2,506	1,381	W	W	W	31,130
West North Central	2,829	548	W	W	--	W	4,362
South Atlantic	W	10,678	722	W	19	1,066	58,485
East South Central	12,983	69	W	118	W	--	13,249
West South Central	80,776	2,190	566	385	W	W	83,994
Mountain	5,347	3,921	863	550	--	2,800	13,480
Pacific	32,691	23,586	2,639	18,060	1,535	489	79,001
U.S. Total	**271,528**	**69,831**	**11,059**	**21,214**	**2,659**	**6,133**	**382,423**
				1997			
New England	W	13,892	460	--	--	W	30,273
Middle Atlantic	W	13,799	3,873	W	951	1,510	68,518
East North Central	27,406	2,476	1,399	--	W	W	31,366
West North Central	2,863	588	W	W	--	W	4,807
South Atlantic	42,180	10,889	746	W	W	1,358	55,555
East South Central	12,330	306	W	114	W	--	12,860
West South Central	86,424	3,801	539	427	W	W	91,270
Mountain	5,483	3,901	865	503	--	2,991	13,744
Pacific	31,872	21,874	2,577	17,718	1,582	480	76,103
U.S. Total	**271,330**	**71,526**	**10,946**	**21,192**	**2,983**	**6,519**	**384,496**
				1998			
New England	15,408	19,967	456	--	--	5,521	41,352
Middle Atlantic	46,083	13,024	3,596	1,517	883	1,476	66,579
East North Central	25,430	6,468	2,367	--	17	44	34,325
West North Central	3,143	669	427	1,146	--	21	5,405
South Atlantic	42,059	10,481	772	6	31	1,373	54,720
East South Central	12,955	5,155	92	114	56	--	18,372
West South Central	88,639	5,718	552	368	--	77	95,354
Mountain	5,607	4,287	856	488	--	2,451	13,689
Pacific	33,678	22,928	2,657	17,977	1,562	12,765	91,567
U.S. Total	**273,002**	**88,697**	**11,774**	**21,615**	**2,548**	**23,728**	**421,364**
				1999			
New England	15,178	26,710	528	—	—	26,322	68,738
Middle Atlantic	45,792	48,804	3,142	1,483	1,000	10,658	110,879
East North Central	25,748	15,368	1,893	—	7	147	43,163
West North Central	4,237	1,286	472	1,024	—	54	7,073
South Atlantic	40,587	11,851	889	2	25	1,970	55,324
East South Central	12,317	12,540	96	117	53	460	25,584
West South Central	94,524	6,873	245	448	—	85	102,175
Mountain	5,522	23,405	916	524	—	2,108	32,475
Pacific	34,634	40,831	2,645	17,431	1,514	26,871	123,926
U.S. Total	**278,538**	**187,668**	**10,826**	**21,030**	**2,599**	**68,676**	**569,336**

W = Withheld to avoid disclosure of individual company data.

Notes: •All data are for 1 megawatt and greater. •Data 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, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 61. Consumption of Fossil Fuels at U.S. Nonutility Generating Facilities by State, 1999

State	Coal (thousand short tons)				Petroleum (thousand barrels)				Gas (thousand Mcf)	
	Anthra-cite[1]	Bituminous[2]	Lignite	Total	Heavy Oil	Light Oil	Total	Petroleum Coke (thousand short tons)	Natural Gas	Other Gas
Alaska	—	603	—	603	36	131	167	—	10,136	—
Alabama	—	783	—	783	388	402	790	—	44,778	4,699
Arkansas	—	115	—	115	110	10	120	—	32,451	1
Arizona	—	352	—	352	8	2	10	—	4,402	—
California	—	1,760	918	2,678	161	223	384	1,720	768,091	25,103
Colorado	—	338	—	338	98	—	98	—	32,923	—
Connecticut	—	624	—	624	4,297	489	4,786	—	24,850	403
District of Columbia	—	—	—	—	—	—	—	—	—	—
Delaware	—	56	—	56	547	—	547	268	—	4,781
Florida	—	2,549	—	2,549	2,060	111	2,171	—	69,421	40,937
Georgia	—	1,770	—	1,770	1,948	598	2,546	292	18,946	—
Hawaii	—	708	—	708	3,121	459	3,580	—	—	101
Iowa	—	2,058	—	2,058	9	8	17	4	10,504	—
Idaho	—	183	—	183	7	—	7	—	6,912	—
Illinois	—	6,787	—	6,787	136	796	932	120	38,297	7,880
Indiana	—	465	—	465	655	80	735	—	35,298	217,736
Kansas	—	—	—	—	—	1	1	—	2,129	—
Kentucky	—	4,885	—	4,885	—	43	43	—	95	—
Louisiana	—	26	—	26	108	3	111	588	219,234	30,641
Massachusetts	—	3,856	—	3,856	17,663	1,574	19,237	—	92,245	—
Maryland	—	453	—	453	327	41	368	—	7,945	10,927
Maine	—	591	—	591	9,016	134	9,150	52	691	37
Michigan	—	1,322	—	1,322	162	35	197	204	41,028	—
Minnesota	—	1,823	—	1,823	1,645	4,281	5,926	—	17,531	—
Missouri	—	415	—	415	19	12	31	—	932	—
Mississippi	—	6	—	6	6	13	19	—	25,102	—
Montana	—	10,703	—	10,703	769	13	782	265	3,405	562
North Carolina	—	2,606	—	2,606	2,764	65	2,829	—	5,618	—
North Dakota	—	276	—	276	100	—	100	—	67	2,643
Nebraska	—	80	—	80	—	2	2	—	157	—
New Hampshire	—	—	—	—	705	74	779	—	121	—
New Jersey	—	808	—	808	173	923	1,096	—	134,761	11,972
New Mexico	—	—	—	—	2	6	8	—	12,220	—
Nevada	—	806	—	806	3	3	6	—	24,850	—
New York	24	5,424	—	5,448	2,513	2,895	5,408	129	283,572	5,561
Ohio	—	668	—	668	31	24	55	—	5,139	19,600
Oklahoma	—	1,737	—	1,737	103	1	104	—	20,347	3,238
Oregon	—	58	—	58	2	—	2	—	34,478	—
Pennsylvania	4,294	12,317	—	16,611	374	432	806	10	23,880	24,464
Rhode Island	—	—	—	—	1,284	4,021	5,305	—	33,511	—
South Carolina	—	614	—	614	348	10	358	—	7,795	6
South Dakota	—	—	—	—	—	—	—	—	—	—
Tennessee	—	2,281	—	2,281	38	1	39	—	10,216	3,381
Texas	—	2,420	246	2,666	707	45	752	527	674,893	179,577
Utah	—	478	—	478	—	3	3	—	1,137	275
Virginia	—	3,376	—	3,376	1,003	1,237	2,240	—	25,371	—
Vermont	—	—	—	—	12	—	12	—	—	—
Washington	—	88	—	88	464	21	485	—	31,030	2,364
Wisconsin	—	1,626	—	1,626	522	960	1,482	153	18,024	—
West Virginia	—	1,588	—	1,588	15	—	15	—	9,787	60,502
Wyoming	—	503	—	503	81	5	86	—	5,420	2,246
U.S. Total	**4,318**	**80,985**	**1,164**	**86,467**	**54,540**	**20,187**	**74,727**	**4,332**	**2,869,740**	**659,637**

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

Table 62. U.S. Nonutility Electricity Supply and Disposition for Generating Facilities by Census Division and State, 1998 and 1999

(Million Kilowatthours)

Census Division and State	Gross Generation		Receipts[1]		Sales[2]		Facility Use	
	1998	1999	1998	1999	1998	1999	1998	1999
New England	**41,352**	**68,738**	**2,551**	**2,949**	**34,071**	**58,706**	**9,209**	**13,479**
Connecticut	4,820	8,585	272	321	4,057	7,590	1,035	1,316
Maine	7,876	12,065	1,046	1,343	3,321	8,670	4,944	4,736
Massachusetts	20,453	38,175	929	948	19,148	33,206	2,233	6,417
New Hampshire	1,919	2,378	197	228	1,479	1,952	634	654
Rhode Island	5,759	6,547	104	104	5,560	6,346	303	304
Vermont	525	989	4	5	505	941	62	52
Middle Atlantic	**66,579**	**110,879**	**5,196**	**4,493**	**56,605**	**98,651**	**15,170**	**17,102**
New Jersey	18,551	18,568	852	913	16,580	16,590	2,823	2,913
New York	29,832	49,068	1,601	1,514	26,696	45,528	4,737	5,391
Pennsylvania	18,197	43,244	2,743	2,066	13,329	36,533	7,610	8,799
East North Central	**34,325**	**43,163**	**17,001**	**17,975**	**19,031**	**26,986**	**32,212**	**34,202**
Illinois	7,806	13,802	6,152	5,446	3,602	9,765	10,341	9,534
Indiana	4,924	7,996	3,309	4,618	758	2,783	7,408	9,831
Michigan	15,992	15,862	1,646	1,832	13,419	13,244	4,219	4,450
Ohio	1,584	1,535	2,920	3,184	65	74	4,439	4,645
Wisconsin	4,019	3,968	2,974	2,894	1,188	1,120	5,805	5,742
West North Central	**5,405**	**7,073**	**5,031**	**5,744**	**1,868**	**3,031**	**8,568**	**9,785**
Iowa	1,183	1,858	1,285	2,020	240	556	2,229	3,323
Kansas	107	69	1,105	1,092	11	22	1,201	1,139
Minnesota	3,568	4,569	2,190	2,207	1,590	2,428	4,168	4,348
Missouri	311	332	282	259	26	25	567	566
Nebraska	79	78	58	58	—	—	136	136
North Dakota	158	166	111	108	1	1	268	273
South Dakota	–-	–-	–-	–-	–-	–-	–-	–-
South Atlantic	**54,720**	**55,324**	**17,230**	**16,014**	**31,085**	**32,973**	**40,929**	**38,931**
Delaware	620	657	427	376	57	27	990	1,007
District of Columbia	—	—	—	—	—	—	—	—
Florida	21,067	21,316	1,668	1,749	13,173	13,954	9,562	9,112
Georgia	6,956	7,349	3,513	3,143	1,229	1,930	9,293	9,127
Maryland	2,230	2,480	2,041	1,818	1,669	1,814	2,602	2,484
North Carolina	8,685	7,911	3,419	3,722	6,106	5,631	6,009	6,004
South Carolina	2,981	3,069	1,089	582	1,003	1,295	3,067	2,357
Virginia	8,806	9,355	3,156	3,086	6,525	7,038	5,438	5,403
West Virginia	3,375	3,186	1,918	1,536	1,324	1,284	3,968	3,438
East South Central	**18,372**	**25,584**	**8,552**	**8,971**	**6,809**	**13,174**	**20,115**	**21,381**
Alabama	6,976	7,165	3,503	3,629	856	1,023	9,623	9,772
Kentucky	5,119	11,804	—	—	5,060	10,851	60	952
Mississippi	2,532	2,781	1,765	2,111	27	294	4,269	4,598
Tennessee	3,745	3,833	3,284	3,231	867	1,006	6,162	6,058
West South Central	**95,354**	**102,175**	**23,605**	**21,838**	**38,475**	**41,124**	**81,027**	**82,880**
Arkansas	2,601	2,566	754	860	53	46	3,302	3,380
Louisiana	24,218	25,885	8,903	7,727	4,080	4,300	29,041	29,312
Oklahoma	4,930	4,875	1,180	1,249	3,643	3,614	2,977	2,509
Texas	63,605	68,850	12,767	12,002	30,699	33,164	45,707	47,679
Mountain	**13,689**	**32,475**	**4,284**	**4,079**	**11,040**	**33,782**	**6,933**	**8,509**
Arizona	821	940	236	234	411	434	645	740
Colorado	3,491	3,439	176	160	3,334	3,262	334	337
Idaho	1,922	1,986	1,188	1,146	1,816	1,849	1,294	1,283
Montana	885	17,212	393	403	756	21,181	522	1,993
Nevada	4,169	6,488	1	2	3,843	6,152	328	338
New Mexico	935	948	1,520	1,393	500	497	1,954	2,012
Utah	792	763	538	464	372	389	958	838
Wyoming	674	699	232	277	8	18	898	968
Pacific	**91,567**	**123,926**	**7,227**	**7,625**	**76,275**	**104,095**	**22,609**	**23,958**
Alaska	1,308	1,231	127	121	222	337	1,211	1,014
California	76,021	108,228	2,811	3,489	64,342	91,998	14,483	16,088
Hawaii	4,115	4,160	35	23	3,519	3,479	723	702
Oregon	4,921	5,126	680	722	4,471	4,619	1,136	1,360
Washington	5,203	5,181	3,574	3,270	3,722	3,662	5,056	4,794
U.S. Total	**421,364**	**569,336**	**90,675**	**89,688**	**275,260**	**412,522**	**236,770**	**250,227**

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-860B is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures attribute to the disparity.

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

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

Table 63. Estimated Emissions from U.S. Nonutility Generating Facilities by Census Division, 1995 Through 1999
(Thousand Short Tons)

Census Division	Sulfur Dioxide[1]	Nitrogen Oxides[1]	Carbon Dioxide[1]
	1995		
New England	22	33	15,123
Middle Atlantic	72	105	40,415
East North Central	103	102	19,462
West North Central	19	12	3,679
South Atlantic	197	158	39,502
East South Central	39	24	4,104
West South Central	185	123	46,048
Mountain	7	24	5,471
Pacific Contiguous	23	71	30,194
Pacific Noncontiguous	6	9	3,757
U.S. Total	**673**	**661**	**207,755**
	1996		
New England	25	34	15,886
Middle Atlantic	71	111	40,717
East North Central	106	138	22,076
West North Central	19	11	3,398
South Atlantic	156	137	38,310
East South Central	42	26	5,090
West South Central	197	120	46,537
Mountain	6	25	6,517
Pacific Contiguous	23	72	30,602
Pacific Noncontiguous	5	11	3,840
U.S. Total	**650**	**685**	**212,973**
	1997		
New England	23	34	16,749
Middle Atlantic	95	97	41,022
East North Central	99	92	16,386
West North Central	19	13	3,999
South Atlantic	164	110	36,092
East South Central	41	19	5,368
West South Central	176	121	54,142
Mountain	8	14	6,279
Pacific Contiguous	38	71	34,026
Pacific Noncontiguous	8	12	4,611
U.S. Total	**671**	**583**	**218,674**
	1998		
New England	61	46	23,470
Middle Atlantic	49	92	40,694
East North Central	116	94	19,873
West North Central	18	13	4,561
South Atlantic	143	114	35,772
East South Central	55	32	9,574
West South Central	178	182	64,162
Mountain	5	17	6,253
Pacific Contiguous	21	80	37,968
Pacific Noncontiguous	5	11	3,654
U.S. Total	**651**	**681**	**232,132**
	1999		
New England	164	82	40,059
Middle Atlantic	383	187	68,103
East North Central	145	78	23,534
West North Central	19	13	4,992
South Atlantic	156	117	33,241
East South Central	151	53	15,634
West South Central	160	134	53,092
Mountain	143	70	27,934
Pacific Contiguous	44	106	52,707
Pacific Noncontiguous	4	10	3,329
U.S. Total	**1,369**	**850**	**322,625**

[1] In 1998, emission factors for the calculation of carbon dioxide and the reductions from nitrogen oxide and sulfur dioxide have been changed--historical data were revised to reflect that change--see technical notes for more information. In 1995, the useful thermal output produced additional emissions of 725 thousand short tons of sulfur dioxide, 538 thousand short tons of nitrogen oxides, and 119,752 thousand short tons of carbon dioxide. In 1996, the useful thermal output produced additional emissions of 810 thousand short tons of sulfur dioxide, 573 thousand short tons of nitrogen oxides, and 133,989 thousand short tons of carbon dioxide. In 1997, the useful thermal output produced additional emissions of 775 thousand short tons of sulfur dioxide, 473 thousand

short tons of nitrogen oxides, and 143,824 thousand short tons of carbon dioxide. In 1998, the useful thermal output produced additional emissions of 761 thousand short tons of sulfur dioxide, 492 thousand short tons of nitrogen oxides, and 145,486 thousand short tons of carbon dioxide. In 1999, the useful thermal output produced additional emissions of 675 thousand short tons of sulfur dioxide, 539 thousand short tons of nitrogen oxides, and 179,301 thousand short tons of carbon dioxide.

Notes: •All data are for 1 megawatt and greater. •Estimates 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.

Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: 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 Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy (DOE). Data published in the *Electric Power Annual Volume II* are compiled from seven forms filed annually by electric utilities and one form filed annually by nonutility power producers. Those forms are: the Form EIA-861, "Annual Electric Utility Report"; the Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others"; the Form EIA-412, "Annual Report of Public Electric Utilities"; the Form EIA-767, "Steam-Electric Plant Operation and Design Report"; the Form EIA-860A, "Annual Electric Generator Report - Utility"; the Form EIA-860B, "Annual Electric Generator Report - Nonutility"; the Department of Energy, Office of Emergency Planning Form EIA-411, "Coordinated Bulk Power Supply Program Report"; and the Department of Energy, Office of Fuels Programs, Fossil Energy Form FE-781R, "Annual Report of International Electric Export/Import Data." Each form is summarized below.

Form EIA-861

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

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

Data Processing. The Form EIA-861 is mailed to the respondents to collect data as of the end of the calendar year. The completed forms are to be returned to the EIA by April 30. The data are entered into the interactive on-line system. Internal edit checks are performed to verify that current data total across and between schedules and are comparable to data reported the previous year. Edit checks are also performed to compare data reported on the Form EIA-861 and similar data reported on the Forms EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions," the FERC Form 1, and the Form EIA-412. These are utility-level checks. Respondents are telephoned to obtain clarification of reported data and to obtain missing data.

FERC Form 1

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

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

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

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

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

Form EIA-412

The Form EIA-412 is a restricted-universe census used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Those publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had 150,000 megawatthours of sales to ultimate consumers and/or 150,000 megawatthours of sales for resale for the 2 previous years, as reported on the Form EIA-861, "Annual Electric Utility Report," must submit the Form EIA-412. The 1995-1997 data represents those electric utilities meeting a threshold of 120,000 megawatthours ultimate consumers' sales and or resales. The criteria used to select the respondents for this survey results in approximately 500 publicly owned electric utilities.

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

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

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

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

Form EIA-767

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

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

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

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

Form EIA-860A

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

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

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

Form EIA-411

The Form EIA-411 is filed annually as a voluntary report. The information reported includes: (1) actual energy and peak demand for the preceding year and 5 additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; and (5) bulk power system maps. These data support queries from the executive branch, Congress, other public agencies, and the general public. These reports present various council aggregate totals for their member electric utilities, with some nonmember information included.

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

Data Processing. The Form EIA-411 is filed annually on June 1 by the 10 North American Electric Reliability Councils. The forms are compiled from data furnished by electric utilities and nonutilities (members, associates, and for nonmembers) within the council areas.

Form FE-781R

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

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

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

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

Form EIA-860B

In 1998, the Form EIA-867, "Annual Nonutility Power Producer Report," was renamed Form EIA-860B, "Annual Electric Generator Report - Nonutility." The Form EIA-860B is a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a contract for the electric energy, or (3) financial closure on the facility. The Form consists of Schedules I, "Identification and Certification;" Schedule II, "Facility Information"; Schedule III, "North American Industry Classification System"; Schedule IVA, "Facility Fuel Information"; Schedule IVB, "Facility Thermal and Generation Information"; Schedule V, "Facility Environmental Information"; and Schedule VI, "Electric Generator Information."

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

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

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

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

Data Quality. The Manufacturing Energy Consumption Survey (MECS) produces detailed estimates of manufacturing electricity generation by industry and Census Division on a triennial basis. The data are published in the *Manufacturing Energy Consumption Survey, Consumption of Energy*. Gross generation by nonutility power producers by major industry groups, and Census division, for 1995 through 1999 presented in this report, are reasonable given the growth in manufacturing on site generation.

Data for the Form EIA-860B are collected from all existing and planned nonutility generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. These data are aggregated to provide geographic totals for selected States and at the Census division and national levels. The Form EIA-867 data are considered confidential (1995 through 1997). Therefore, suppression of some data is necessary to protect the confidentiality of the individual respondent data. See "Confidentiality of the Data" in this section for further information on the nondisclosure of data. In 1998 and 1999, the Form EIA-860B data that are confidential are planned units that have sales to other end-users.

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

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

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

- For generating units that use energy sources that are not burned (hydraulic, geothermal, nuclear, solar, or wind energy), the generation is allocated to that energy source (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.

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

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

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

Shown below are the conversion factors used to 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.

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

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

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

Emissions for the Production of Electricity Methodology. Emissions for nonutility power producers include emissions from cogeneration facilities that produce electric power as an integral part of a manufacturing or other thermal consuming process. Emissions are directly proportional to the quantities of fuels consumed. To calculate emissions for the production of electricity, a methodology was developed to estimate the consumption of fuel associated for the production of electricity by cogeneration facilities. The methodology is based on 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:

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

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

Business Classification. The nonutility industry consists of all manufacturing, agricultural, forestry, transportation, finance, service and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual.[15] In 1997, the SIC Manual name was changed to North American Industry Classification System (NAICS). The following is a list from the Form EIA-860B of the main classifications and the category of primary business activity within each classification.

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

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

Mining
2122 Metal mining
2121 Coal mining
211 Oil and gas extraction
2123 Mining and quarrying of nonmetallic minerals
except fuels

Construction
23

Manufacturing
311 Food and kindred products
3122 Tobacco products
314 Textile and mill products
315 Apparel and other finished products made from fabrics and similar materials
321 Lumber and wood products, except furniture
337 Furniture and fixtures
322 Paper and allied products (other than 322122 or 32213)
- 322122 Paper mills, except building paper
- 32213 Paperboard mills

323 Printing and publishing
325 Chemicals and allied products (other than 325188, 325211, 32512, or 325311)
- 325188 Industrial Inorganic Chemicals
- 325211 Plastics materials and resins
- 32512 Industrial organic chemicals
- 325311 Nitrogenous fertilizers

324 Petroleum refining and related industries (other than 32411)
- 32411 Petroleum refining

326 Rubber and miscellaneous plastic products
316 Leather and leather products
327 Stone, clay, glass, and concrete products (other than 32731)
- 32731 Cement, hydraulic

331 Primary metal industries (other than 331111 or 331312)
- 331111 Blast furnaces and steel mills
- 331312 Primary aluminum

332 Fabricated metal products, except machinery and transportation equipment
333 Industrial and commercial equipment and components except computer equipment
335 Electronic and other electrical equipment and components except computer equipment
336 Transportation equipment
3345 Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
339 Miscellaneous manufacturing industries

Transportation and Public Utilities
482 Railroad transportation
485 Local and suburban transit and interurban highway passenger transport
484 Motor freight transportation and warehousing
491 United States Postal Service
483 Water transportation
481 Transportation by air
486 Pipelines, except natural gas
487 Transportation services
513 Communications
22 Electric, gas, and sanitary services
- 2212 Natural gas transmission
- 2213 Water supply
- 22132 Sewerage systems
- 562212 Refuse systems
- 22131 Irrigation systems

Wholesale Trade
421 to 422

Retail Trade
441 to 454

Finance, Insurance, and Real Estate
521 to 533

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

92 Public Administration
92

Other (explain):

Historically, (Tables 55 and 59) show cogeneration facilities reporting the Standard Classification Code (SIC) that identified the user of the electric and/or thermal energy. Beginning in 1993, the SIC code was broadened to include the SIC code(s) of the producing facility based on the facilities consumption. This revision provides an alternative method of comparing power needs and utilization within the nonutility power industry. Since 1998, all the tables are based on North American Industry Classification System. Tables A1 and A2 show the installed capacity and gross generation of electricity by the producing energy group, respectively.

Quality of Data

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

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

Data Editing System

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

Confidentiality of the Data

In general, the 1998 and 1999 data collected on the forms used for input to this report are not confidential. However, data from the Form EIA-867, “Annual Nonutility Power Producer Report, (1995-1997)” are considered confidential and must adhere to EIA's “Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA” (45 *Federal Register* 59812 (1980)). In order to protect the confidentiality of individual respondent's data, a procedure was developed to suppress the data for publication. The procedure is described as follows.

Disclosure of Data

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

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

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

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

Rounding Rules for Data

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

CNEAF Data Revision and Policy

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

1. Annual survey data collected by this office are published either as preliminary or final when first appearing in a data report. Data initially released as preliminary will be so noted in the report. These data will be revised, if necessary, and declared final in the next publication of the data.
2. All monthly and quarterly survey data collected by this office are published as preliminary. These data are revised only after the completion of the 12-month cycle of the data. No revisions are made to the published data before this unless approved by the Office Director.
3. The magnitude of changes due to revisions experienced in the past will be included in the data reports, so that the reader can assess the accuracy of the data.
4. After data are published as final, corrections will be made only in the event of a greater than one percent difference at the national level. Corrections for differences that are less than the before-mentioned threshold are left to the discretion of the Office Director.

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

- **U.S. Electric Utility Retail Sales and Revenue** Data on sales, revenue, and average revenue per kilowatthour from the Form EIA-861 for 1999 are final.
- **U.S. Electric Utility Financial Statistics** Financial data from the Federal Energy Regulatory Commission Form 1 for 1999 are preliminary and the Form EIA-412 for 1999 are final.
- **U.S. Electric Utility Environmental Statistics** Data from the Form EIA-767 for 1999 are final pending approval of the Environmental Protection Agency.
- **U.S. Electric Power Transactions** All data from the Forms EIA-411, EIA-860A, and EIA-861 are final. Data from the Form FE-781R are final.
- **U.S. Electric Utility Demand-Side Management** All data on demand-side management from the Form EIA-861 are final.
- **U.S. Nonutility Power Producers** Data from the Form EIA-867 for 1995 through 1997 are final. Data from Form EIA-860B for 1998 and 1999 are final.

Formulas and Calculations

Average Heat Content

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

Percent Difference

The following formula is used to calculate percent differences.

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

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

Form EIA-861

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

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

Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric utility for providing electrical service. The average revenue per kilowatthour reported in this publication by sector represents a weighted average of consumer revenue and sales within that sector and across sectors for all consumers.

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

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

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

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

FERC Form 1

Composite Financial Indicators for Major Investor-Owned Electric Utilities

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

Electric Fixed Asset (Net Plant) Turnover =

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

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

Total Asset Turnover =

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

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

Current Assets to Current Liabilities =

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

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

Long-term Debt to Capitalization =

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

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

Preferred Stock to Capitalization =

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

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

Common Stock Equity to Capitalization =

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

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

Total Debt to Total Assets =

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

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

Common Stock Equity to Total Assets =

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

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

Interest Coverage Before Taxes Without AFUDC =

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

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" (Tables A3 and A5).[16] Emissions of SO_2 and NO_x have been revised from the updated Air Pollutant Emissions Factor (AP-42 5th edition, through Supplement E) of the Environmental Protection Agency on July 1999. Environmental Protection Agency emission factors are based on boiler type, firing configuration, and fuel burned. The methodology for determining emissions of CO_2 has been revised since the 1997 publication.

The coefficients for determining emissions of CO_2 from electric utility power plants come from the publication, *Emissions of Greenhouse Gases in the United States*, (DOE/EIA-0573). The nonutility coefficients were developed to be consistent with the utility coefficients.

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

Methodology

The methodology for developing the CO_2 emission estimates for steam utility plants and nonsteam utility plants (calculations done on a plant basis by fuel), as well as for nonutility plants (calculations done on a facility basis by fuel), is as follows:

Steam Utility Plants

Step 1. Sum of Monthly Consumption (EIA-767) times Monthly Average Btu Content (EIA-767) divided by Total Annual Consumption (EIA-767) = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-767) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) times CO_2 factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Step 5. Divide Annual CO_2 Emissions (Step 4) by 2000 to obtain result in short tons.

Nonsteam Utility Plants

Step 1(a). If monthly EIA-759 and monthly FERC-423 is available: Sum of Monthly Consumption (EIA-759) times Monthly Average Btu Content (FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 1(b). If monthly EIA-759 is available, but not monthly FERC-423: Sum of Monthly Consumption (EIA-759) times Average Monthly Btu Content (calculated from FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 1(c). If only annual EIA-759 is available: Annual Consumption (EIA-759) times Average Annual Btu Content (calculated from FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-759) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) x CO_2 Factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Step 5. Divide Annual CO_2 Emissions (Step 4) by 2000 to obtain result in short tons.

Coal Rank and Emissions. In 1992, a special study of the relationship between the heat and carbon content of coal was completed by the Energy Information Administration's Analysis and Systems Division of the Office of Coal, Nuclear, Electric and Alternate Fuels. The hypothesis underlying this study was that the ratio of carbon-to-heat content varies not only by coal rank (i.e., anthracite, bituminous, subbituminous, and lignite), but also by geographic location of the coal. In this study, the hypothesis was tested and the results of the analysis supported the hypothesis. That is, it was concluded from the analysis that coal rank and location of the coal are significant factors in the variation of the ratio of carbon-to-heat content. After this determination, a set of emission factors, by rank and State were derived on the basis of data contained in EIA's Coal Analysis File.[17]

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 are based on 100-percent combustion of the carbon in the fuel. Since a small percentage of the carbon in the coal is not converted to CO_2, this publication assumes 99 percent combustion. The 1 percent of emissions is deducted at the State/National level. The emissions at the State level are based on the State in which the plant is located.

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

[17] For a description of the methodology and data used 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.

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.[18] 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 emission limits on the Form EIA-767. To determine controlled SO_2 emissions, the uncontrolled emissions are reduced by the annual average removal efficiencies reported on the Form EIA-767. This emission is the controlled emission. As a check, the controlled emission is compared with the most stringent legal limit reported on the Form EIA-767. The controlled emission should be less than the legal limit because research indicates that 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 1996 CEMS emissions data by state and plant in its publication *Acid Rain Program, Emissions Scorecard 1996 (EPA430/R-97-025)* .

Preliminary 1996 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 electric utility plants for which both EPA and EIA collected data. On a national basis, the data collected by EPA is 2.5 percent higher than SO_2 emissions calculated by EIA.

Controlled Nitrogen Oxide Emissions. The controlled NO_x emission is calculated by applying the appropriate reduction factor in Table A6. 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.

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.

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

Air Emissions from Small Plants. The Form EIA-767 does not collect data for generators powered by internal combustion engines, gas turbines, combined cycle units (for example, gas turbines with waste heat boilers), and boilers at steam-electric plants with a total nameplate capacity of less than 10 MW. Accordingly, utility air emissions from these generators are not estimated by the methodology. An estimate of air emissions from these generating units based on a similar methodology using 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-860B, "Annual Electric Generator Report-Nonutility." Form EIA-860B collects information anually from all nonutility power producers with a total generator nameplate rating of 1 megawatt (MW)

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

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-860B.

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."[19] However, the boiler type and firing configuration are not reported on the Form EIA-860B so all boilers are assumed to be large boilers[20] 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-860B. The methodology developed for CO_2 emission estimates for nonutility plants is as follows:

Step 1. Annual Consumption (EIA-860B) times Average Annual Btu Content (calculated from FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-860B) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) x CO_2 Factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Step 5. Divide Annual CO_2 Emissions (Step 4) by 2000 to obtain result in short tons.

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-860B. 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-860B. 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

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

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

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-860B 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 A6.

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-860B. For facilities reporting electrical generation before August 1973, no control equipment is assumed and the controlled NO_x emission 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-860B; therefore, no estimates of controlled CO_2 emissions are provided.

Table A1. Installed Capacity at U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1995 Through 1999

(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1995			
New England	1,247	3,718	72	--	--	--	5,037
Middle Atlantic	2,225	10,127	W	W	--	W	12,477
East North Central	3,021	2,489	323	W	W	W	5,917
West North Central	755	131	131	W	W	W	1,232
South Atlantic	4,653	8,090	100	W	W	78	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**	**40,962**	**1,186**	**1,369**	**273**	**561**	**70,254**
				1996			
New England	1,190	3,938	75	--	--	--	5,202
Middle Atlantic	1,757	W	105	--	--	W	12,987
East North Central	3,076	2,584	331	W	W	W	6,074
West North Central	762	145	135	W	--	W	1,255
South Atlantic	4,690	W	96	W	64	81	13,662
East South Central	1,997	129	W	26	W	--	2,167
West South Central	W	4,636	197	72	W	--	14,433
Mountain	W	W	W	242	--	W	2,881
Pacific	2,460	11,120	169	595	99	85	14,527
U.S. Total	**25,850**	**44,457**	**1,168**	**1,204**	**179**	**331**	**73,189**
				1997			
New England	1,166	4,062	67	--	--	--	5,295
Middle Atlantic	1,718	W	99	--	--	W	13,020
East North Central	3,034	2,682	382	W	W	W	6,183
West North Central	788	475	135	W	--	W	1,611
South Atlantic	4,724	W	86	W	139	99	13,810
East South Central	1,961	204	W	26	W	--	2,212
West South Central	W	4,264	197	68	W	--	14,890
Mountain	W	W	W	239	--	W	2,868
Pacific	2,360	10,837	169	595	96	61	14,117
U.S. Total	**26,492**	**44,538**	**1,200**	**1,197**	**252**	**325**	**74,004**
				1998			
New England	1,171	10,582	65	—	—	—	11,818
Middle Atlantic	1,706	10,976	106	—	—	18	12,806
East North Central	2,808	5,031	345	—	5	18	8,207
West North Central	722	616	135	203	—	11	1,686
South Atlantic	4,830	8,565	86	6	63	100	13,650
East South Central	2,042	2,282	14	24	11	—	4,373
West South Central	10,042	5,568	197	66	1	—	15,873
Mountain	407	2,070	52	240	—	118	2,887
Pacific	2,295	23,509	174	655	91	61	26,785
U.S. Total	**26,022**	**69,201**	**1,172**	**1,193**	**170**	**326**	**98,085**
				1999			
New England	969	18,457	58	—	—	—	19,484
Middle Atlantic	1,335	33,406	75	2	—	18	34,837
East North Central	2,861	27,637	173	—	3	18	30,691
West North Central	546	1,205	109	2,025	—	11	3,896
South Atlantic	4,180	9,980	79	6	63	108	14,416
East South Central	1,733	4,225	14	26	11	—	6,009
West South Central	10,185	7,587	74	72	—	11	17,929
Mountain	326	6,214	50	235	—	17	6,842
Pacific	1,833	31,131	99	170	7	15	33,254
U.S. Total	**23,967**	**139,843**	**729**	**2,536**	**83**	**198**	**167,357**

W = Withheld to avoid disclosure of individual company data.

Notes: •All data are for 1 megawatt and greater. •Data are final; •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table A2. Gross Generation of U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1995 Through 1999
(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1995			
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	31,283	237	W	W	W	57,624
East South Central	11,593	W	W	125	W	--	12,708
West South Central	57,667	25,861	614	492	--	--	84,635
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**	**215,233**	**4,196**	**6,440**	**1,217**	**1,422**	**375,901**
				1996			
New England	5,940	23,653	268	--	--	--	29,862
Middle Atlantic	9,433	W	463	--	--	W	68,860
East North Central	14,795	14,988	1,232	W	W	W	31,130
West North Central	2,829	W	305	W	--	W	4,362
South Atlantic	25,712	W	247	W	19	138	58,485
East South Central	12,132	W	W	118	W	--	13,249
West South Central	W	26,598	566	385	W	--	83,994
Mountain	W	W	W	550	--	W	13,480
Pacific	13,970	59,471	838	4,096	389	237	79,001
U.S. Total	**143,304**	**227,736**	**4,164**	**5,783**	**480**	**956**	**382,423**
				1997			
New England	6,051	23,976	246	--	--	--	30,273
Middle Atlantic	9,526	W	463	--	--	W	68,518
East North Central	14,891	15,118	1,288	--	W	W	31,366
West North Central	2,863	685	327	W	--	W	4,807
South Atlantic	25,499	29,337	W	W	W	146	55,555
East South Central	11,381	1,255	W	114	W	--	12,860
West South Central	W	27,145	539	427	W	--	91,270
Mountain	W	W	232	503	--	W	13,744
Pacific	13,663	57,015	775	4,059	410	182	76,103
U.S. Total	**149,106**	**223,383**	**4,125**	**6,028**	**860**	**995**	**384,496**
				1998			
New England	6,078	35,027	246	—	—	—	41,352
Middle Atlantic	9,284	56,768	456	—	—	71	66,579
East North Central	13,709	19,246	1,310	—	17	44	34,325
West North Central	3,138	779	322	1,146	—	21	5,405
South Atlantic	25,300	29,001	237	6	31	145	54,720
East South Central	12,088	6,022	92	114	56	—	18,372
West South Central	60,498	33,937	552	368	—	—	95,354
Mountain	2,157	10,424	225	488	—	395	13,689
Pacific	11,925	74,170	850	4,047	410	165	91,567
U.S. Total	**144,177**	**265,375**	**4,291**	**6,169**	**513**	**840**	**421,364**
				1999			
New England	4,674	63,844	220	—	—	—	68,738
Middle Atlantic	7,181	103,315	314	—	—	69	110,879
East North Central	13,011	29,512	596	—	7	38	43,163
West North Central	2,454	3,276	298	1,024	—	20	7,073
South Atlantic	22,095	32,666	339	2	25	196	55,324
East South Central	10,581	14,736	96	117	53	—	25,584
West South Central	58,908	42,666	153	448	—	(*)	102,175
Mountain	1,565	30,119	293	498	—	—	32,475
Pacific	9,043	113,307	409	1,099	37	31	123,926
U.S. Total	**129,512**	**433,441**	**2,718**	**3,188**	**122**	**355**	**569,336**

(*) Denotes less than one-half the unit of measure.
W = Withheld to avoid disclosure of individual company data.
Notes: •All data are for 1 megawatt and greater. •Data are final; •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Data for 1998 and 1999: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: 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]	Emission Factors: Nitrogen Oxides[2]	Emission Factors: Carbon Dioxide[3]
Utility				
Coal and Other Solid Fuels		**lbs per ton**	**lbs per ton**	**lbs per 10^6 Btu**
Bituminous[4]	cyclone	38.00 x S	33.0	See Table A4
	fluidized bed[5]	31.00 x S	5.0	See Table A4
	spreader stoker	38.00 x S	11.0	See Table A4
	tangential	38.00 x S	15.0(14)	See Table A4
	all others	38.00 x S	22.0(31)	See Table A4
Subbituminous[4]	cyclone	35.00 x S	17.0	See Table A4
	fluidized bed[5]	31.00 x S	5.0	See Table A4
	spreader stoker	38.00 x S	8.8	See Table A4
	tangential	35.00 x S	8.4	See Table A4
	all others	35.00 x S	12.0(24)	See Table A4
Lignite[4]	cyclone	30.00 x S	15.00	See Table A4
	fluidized bed	10.00 x S	3.60	See Table A4
	front/opposed	30.00 x S	13.00	See Table A4
	spreader stoker	30.00 x S	5.80	See Table A4
	tangential	30.00 x S	7.10	See Table A4
	all others	30.00 x S	7.10(13)	See Table A4
Petroleum Coke[6]	fluidized bed[5]	39.00 x S	21.00	225.13
	all others	39.00 x S	21.00	225.13
Refuse	all types	3.90	5.00	199.82
Wood	all types	0.08	1.50	0.00
Petroleum and Other Liquid Fuels		**lbs per 10^3 gal**	**lbs per 10^3 gal**	**lbs per 10^6 Btu**
Residual Oil[7]	tangential	157.00 x S	32.00	173.72
	vertical	157.00 x S	47.00	173.72
	all others	157.00 x S	47.00	173.72
Distillate Oil[7]	all types	150.00 x S	24.00	161.27
Methanol	all types	See Table A5	See Table A5	138.15
Propane (liquid)	all types	86.5	19.00	139.04
Coal-Oil Mixture	all types	See Table A5	See Table A5	173.72
Natural Gas and Other Gaseous Fuels		**lbs per 10^6 cf**	**lbs per 10^6 cf**	**lbs per 10^6 Btu**
Natural Gas	tangential	0.60	170.00	116.38
	all others	0.60	280.00	116.38
Blast Furnance Gas	all types	950.00	280.00	116.38
Nonutility				
Coal and Other Solid Fuels		**lbs per ton**	**lbs per ton**	**lbs per 10^6 Btu**
Anthracite Culm	all types	39.00 x S	1.80	See Table A4
Bituminous[4]	all types	38.00 x S	22.00	See Table A4
Bituminous Gob	all types	38.00 x S	22.00	See Table A4
Subituminous	all types	35.00 x S	12.00	See Table A4
Lignite[4]	all types	30.00 x S	12.00	See Table A4
Lignite Waste	all types	30.00 x S	12.00	See Table A4
Peat	all types	30.00 x S	12.00	See Table A4
Agricultural Waste	all types	See Table A5	See Table A5	0
Black Liquor	all types	See Table A5	See Table A5	0
Chemicals	all types	See Table A5	See Table A5	0
Closed Loop Biomass	all types	See Table A5	See Table A5	0
Internal	all types	See Table A5	See Table A5	0

See footnotes at end of table.

Table A3. Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors (Continued)

Fuel	Boiler Type/ Firing Configuration	Emission Factors		
		Sulfur Dioxide[1]	Nitrogen Oxides[2]	Carbon Dioxide[3]
Coal and Other Solid Fuels (Continued)		**lbs per ton**	**lbs per ton**	**lbs per 10^6 Btu**
Liquid Acetonitrile Waste	all types	See Table A5	See Table A5	150.76
Liquid Waste	all types	2.80	2.30	163.29
Municipal Solid Waste	all types	1.70	5.90	189.48
Petroleum Coke[7]	all types	39.00 x S	14.00	225.13
Pitch	all types	See Table A5	See Table A5	See Table A4
Railroad Ties	all types	See Table A5	See Table A5	0
Red Liquor	all types	See Table A5	See Table A5	0
Sludge	all types	2.80	5.00	0
Sludge Waste	all types	2.80	5.00	0
Sludge Wood	all types	2.80	5.00	0
Spent Sulfite Liquor	all types	See Table A5	See Table A5	0
Straw	all types	See Table A5	See Table A5	0
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	See Table A5	See Table A5	See Table A4
Tires	all types	See Table A5	See Table A5	189.54
Waste Byproducts	all types	1.70	2.30	163.29
Waste Coal	all types	See Table A5	See Table A5	See Table A4
Wood/Wood Waste	all types	0.08	1.50	0
Petroleum and Other Liquid Fuels		**lbs per 10^3 gal**	**lbs per 10^3 gal**	**lbs per 10^6 Btu**
Heavy Oil[7]	all types	157.00 x S	47.00	173.72
Light Oil[7]	all types	142.00 x S	20.00	159.41
Diesel	all types	142.00 x S	20.00	161.27
Kerosene	all types	142.00 x S	20.00	159.41
Butane (liquid)	all types	0.09	21.00	143.20
Fish Oil	all types	See Table A5	See Table A5	0
Methanol	all types	See Table A5	See Table A5	138.15
Oil Waste	all types	147.00 x S	19.00	163.61
Propane (liquid)	all types	0.50	19.00	139.04
Sludge Oil	all types	147.00 x S	19.00	0
Tar Oil	all types	See Table A5	See Table A5	0
Waste Alcohol	all types	See Table A5	See Table A5	138.15
Natural Gas and Other Gaseous Fuels		**lbs per 10^6 cf**	**lbs per 10^6 cf**	**lbs per 10^6 Btu**
Natural Gas	all types	0.60	280.00	116.97
Butane (gas)	all types	0.60	21.00	143.20
Hydrogen	all types	See Table A5	550.00	0
Landfill Gas	all types	See Table A5	550.00	115.12
Methane	all types	See Table A5	550.00	115.11
Other Gas	all types	See Table A5	550.00	141.54
Propane (gas)	all types	0.60	19.00	139.04

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

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

3 Uncontrolled carbon dioxide emission estimates are reduced by 1 percent to account for unburned carbon.

4 Coal types are categorized by Btu content as follows: bituminous (greater than or equal to 9,750 Btu per pound), subbituminous (equal to 7,500 to 9,750 Btu per pound), and lignite (less than 7,500 Btu per pound).

5 Sulfur dioxide emission estimates from fluidized bed boilers assume a sulfur removal efficiency of 90 percent.

6 Emission factors for petroleum coke are assumed to be the same as those for anthracite. If the sulfur content of petroleum coke is unknown, a 6 percent sulfur content is assumed.

7 Oil types are categorized by Btu content as follows: heavy (greater than or equal to 144,190 Btu per gallon), and light (less than 144,190 Btu per gallon).

cf = Cubic Feet.
gal = 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 (through Supplement E), Research Triangle Park, North Carolina, July, 1999. •For carbon dioxide factors: Energy Information Administration, ''Emissions of Greenhouse Gases in the United States 1998,'' November 1999.

Table A4. Carbon Dioxide Emission Factors for Coal by Rank and State of Origin

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

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

Table A5. Sulfur Dioxide and Nitrogen Oxide Factors for Specific Fuels

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

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

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

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

Table A6. Nitrogen Oxide Reduction Factors

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

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

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

Table A7. Unit-of-Measure Equivalents

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

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

Glossary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Bbl: The abbreviation for barrel.

Bcf: The abbreviation for 1 billion cubic feet.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FERC: The Federal Energy Regulatory Commission.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical distribution system.

Gross Generation: The total amount of electric energy produced by a generating facility, as measured at the generator terminals.

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

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Incremental Effects: The annual effects in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused by new participants in existing DSM programs and all participants in new DSM programs during a given year. Reported Incremental Effects should be annualized to indicate the program effects that would have occurred had these participants been initiated into the program on January 1 of the given year. Incremental effects are not simply the Annual Effects of a given year minus the Annual Effects of the prior year, since these net effects would fail to account for program attrition, degradation, demolition, and participant dropouts.

Indirect Utility Cost: A utility cost that may not be meaningfully identified with any particular DSM program category. Indirect costs could be attributable to one of several accounting cost categories (i.e., Administrative, Marketing, Monitoring & Evaluation, Utility-Earned Incentives, Other). Accounting costs that are known DSM program costs should not be reported under Indirect Utility Cost, rather those costs should be reported as Direct Utility Costs under the appropriate DSM program category.

Industrial: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments Standard Industrial Classification (SIC) codes 01-39. The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Inoperable Capacity: Utility-owned or operated capacity that is totally or partially out of service for reasons such as: environmental restrictions, legal or regulatory restrictions, extensive modifications or repair, or capacity specified as being in a mothballed state.

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

Intermediate Load (Electric System): The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peak load, or the load over a specified time period.

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

Internal Demand: Peak hour integrated megawatt demand is defined as the sum of the demands of all customers that a system serves, including the demands of the organization providing the electric service, plus the losses incidental to that service. Total Internal Demand is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) is not included.

Internal Demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Internal Demand should not be reduced by Direct Control Load Management or Interruptible Demand.

Interruptible Demand: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the NERC Council or Reporting Party seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible Demand as reported here does not include Direct Control Load Management.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under certain circumstances, as specified in the service contract.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions. For example, loads that can be interrupted to fulfill planning or operation reserve requirements should be reported as Interruptible Load. Interruptible Load as defined here excludes Direct Load Control and Other Load Management. (Interruptible Load, as reported here, is synonymous with Interruptible Demand reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report," with the exception that annual peak load effects are reported on the Form EIA-861 and seasonal (i.e., summer and winter) peak load effects are reported on the OE-411).

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Leverage Ratio: A measure that indicates the financial ability to meet debt service requirements and increase the value of the investment to the stockholders. (i.e. the ratio of total debt to total assets).

Liability: An amount payable in dollars or by future services to be rendered.

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

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter (used almost exclusively for electric power generation). It is also referred to as brown coal. Comprises two groups classified according to the following ASTM Specification D388-84 for calorific values on a moist material-matter-free basis:

	Limits Btu/lb.	
	GE	LT
Lignite A	6300	8300
Lignite B	-	6300

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

Load Building: Refers to programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building should include programs that promote electric fuel substitution. Load Building effects should be reported as a negative number, shown with a minus sign.

Marketing Cost: Expenses directly associated with the preparation and implementation of the strategies designed to encourage participation in a DSM program. The category excludes general market and load research costs.

Monitoring & Evaluation Cost: Expenditures associated with the planning, collection, and analysis of data used to assess program operation and effects. It includes the activities such as load metering, customer surveys, new technology testing, and program evaluations that are intended to establish or improve the ability to monitor and evaluate the impacts of DSM programs, collectively or individually.

Maximum Demand: The greatest of all demands of the load that has occurred within a specified period of time.

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

MMcf: One million cubic feet.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Capability: The maximum load-carrying ability of the equipment, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. (Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations, and electrical use.)

Net Generation: Gross generation minus plant use from all electric utility owned plants. The energy required for pumping at a pumped-storage plant is regarded as plant use and must be deducted from the gross generation.

Net Internal Demand: Internal Demand less Direct Control Load Management and Interruptible Demand.

Net Summer Capability: The steady hourly output, which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of summer peak demand.

Net Winter Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of winter peak demand.

New Construction: Energy-efficiency program promotion to encourage the building of new homes, buildings, and plants to exceed standard government-mandated energy efficiency codes; it may include major renovations of existing facilities.

Noncoincidental Peak Load: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Non-Firm Power: Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of 10 regional reliability councils and one affiliate member and encompasses essentially all the power regional of the contiguous United States and Alaska, Canada, and Mexico. The NERC Regions are:

ASCC - The Alaska Systems Coordinating Council (affiliate NERC member)

ECAR - East Central Area Reliability Coordination Agreement

ERCOT - Electric Reliability Council of Texas

FRCC - Florida Reliability Coordinating Council

MAAC - Mid-Atlantic Area Council

MAIN - Mid-America Interconnected Network

MAPP - Mid-Continent Area Power Pool

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SPP - Southwest Power Pool

WSCC - Western Systems Coordinating Council

North American Industry Classification System (NAICS): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities. Formerly called the Standard Industrial Classification (SIC) prior to 1997.

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Off-Peak Gas: Gas that is to be delivered and taken on demand when demand is not at its peak.

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 volt produces a current of 1 ampere.

Operable Nuclear Unit: A nuclear unit is “operable” after it completes low-power testing and is granted authorization to operate at full power. This occurs when it receives its full power amendment to its operating license from the Nuclear Regulatory Commission.

Other Cost: A residual category to capture the Indirect Costs of DSM programs that cannot be meaningfully included in any of the other cost categories listed and defined herein. Included are costs such as those incurred in the research and development of DSM technologies.

Other DSM Programs: A residual category to capture the effects of DSM programs that cannot be meaningfully included in any of the program categories listed and defined herein. The energy effects attributable to this category should be the net effects of all the residual programs. Programs that promote consumer's substitution of electricity by other energy types should be included in Other DSM Programs. Also, self-generation should be included in Other DSM Programs to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories.

Other Incentives: Energy Efficiency programs that offer cash or noncash awards to electric energy efficiency deliverers, such as appliance and equipment dealers, building contractors, and architectural and engineering firms, that encourage consumer participation in a DSM program and adoption of recommended measures.

Other Load Management: Refers to programs other than Direct Load Control and Interruptible Load that limit or shift peak load from on-peak to off-peak time periods. It includes technologies that primarily shift all or part of a load from one time-of-day to another and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, and load limiting devices in energy management systems. This category also includes programs that aggressively promote time-of-use (TOU) rates and other innovative rates such as real time pricing. These rates are intended to reduce consumer bills and shift hours of operation of equipment from on-peak to off-peak periods through the application of time-differentiated rates.

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

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Peak Demand: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

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

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes fuel oil No. 2, No. 4, No. 5, No. 6; topped crude; Kerosene; and jet fuel.

Petroleum Coke: See Coke (Petroleum).

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Planned Capacity Resources: Utility- and IPP-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.

Planned Generator: A proposal by a company to install electric generating equipment at an existing or planned facility or site. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure for the facility.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Plant Use: The electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pumped-storage plants.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping at pumped-storage plants is, by definition, subtracted, and the energy production for these plants is then reported as a net figure.

Potential Peak Reduction: The potential annual peak load reduction (measured in kilowatts) that can be deployed from Direct Load Control, Interruptible Load, Other Load Management, and Other DSM Program activities. It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load.

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

Power Pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

Power Marketers: Power marketers are business entities engaged in buying and selling electricity, but do not own generating or transmission facilities. Power marketers, as opposed to Brokers, take ownership of the electricity and are involved in interstate trade. These entities file with FERC for status as a power marketer.

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).

Process Heating: Energy Efficiency program promotion of increased electric energy efficiency applications in industrial process heating.

Profit: The income remaining after all business expenses are paid.

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

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

Purchased Power Adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and it varies from a specified unit base amount.

Pure Pumped-Storage Hydroelectric Plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.) Part 292.

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

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Ratemaking Authority: A utility commission's legal authority to fix, modify, approve, or disapprove rates, as determined by the powers given the commission by a State or Federal legislature.

Receipts: Purchases of fuel.

Regulation: The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Residential: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. For the residential class, do not duplicate consumer accounts due to multiple metering for special services (water, heating, etc.). Apartment houses are also included.

Residual Fuel Oil: The topped crude of refinery operation, includes No. 5 and No. 6 fuel oils as defined in ASTM Specification D396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F-77); and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include imported crude oil burned as fuel.

Restricted-Universe Census: This is the complete enumeration of data from a specifically defined subset of entities including, for example, those that exceed a given level of sales or generator nameplate capacity.

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

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

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

Sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Sales for Resale: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

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

Small Power Producer (SPP): Under the Public Utility Regulatory Policies Act (PURPA), a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resource must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

Spinning Reserve: That reserve generating capacity running at a zero load and synchronized to the electric system.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low-fuel prices.

Stability: The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities (see North American Industry Classification System).

Standby Demand: The Demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Standby Demand is intended to be used infrequently by any one customer.

Standby Facility: A facility that supports a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service.

Standby Service: Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility if a schedule or an agreement authorizes the transaction. The service is not regularly used.

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

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

Subbituminous Coal: Subbituminous coal, or black lignite, is dull black and generally contains 20 to 30 percent moisture. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received and averages about 18 million Btu per ton. Subbituminous coal, mined in the western coal fields, is used for generating electricity and space heating.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Sulfur: One of the elements present in varying quantities in coal which contributes to environmental degradation when coal is burned. In terms of sulfur content by weight, coal is generally classified as low (less than or equal to 1 percent), medium (greater than 1 percent and less than or equal to 3 percent), and high (greater than 3 percent). Sulfur content is measured as a percent by weight of coal on an “as received” or a “dry” (moisture-free, usually part of a laboratory analysis) basis.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Total DSM Cost: Refers to the sum of total utility cost and nonutility cost.

Total DSM Programs: Refers to the total net effects of all the utility's DSM programs. For the purpose of this survey, it is the sum of the effects for Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building. Net growth in energy or load effects should be reported as a negative number, shown with a minus sign.

Total Nonutility Cost: Refers to total cash expenditures incurred by consumers and trade allies that are associated with participation in a DSM program, but that are not reimbursed by the utility. The nonutility expenditures should include only those additional costs necessary to purchase or install an efficient measure relative to a less efficient one. Costs are to be reported in nominal dollars in the year in which they are incurred, regardless of when the actual effects occur. To the extent possible, provide the best estimate of nonutility costs if actual costs are unavailable.

Total Utility Cost: Refers to the sum of the total Direct and Indirect Utility Costs for the year. Utility costs should reflect the total cash expenditures for the year, reported in nominal dollars, that flowed out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occur.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

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

Uniform System of Accounts: Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Useful Thermal Output: The thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation.

Utility-Earned Incentives: Costs in the form of incentives paid to the utility for achievement in consumer participation in DSM programs. These financial incentives are intended to influence the utility's consideration of DSM as a resource option by addressing cost recovery, lost revenue, and profitability.

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Water Heating: Energy Efficiency program promotion to increase efficiency in water heating, including low-flow shower heads and water heater insulation wraps. Could be applicable to residential, commercial, or industrial consumer sectors.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.