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The Changing Structure of the Electric Power Industry, 1970-1991

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Preface

Section 205(a)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Adminis-tration (EIA) to carry out a central, comprehensive, and unified energy data information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information. To assist in meeting these responsibilities in the area of electric power, EIA has prepared this report, *The Changing Structure of the Electric Power Industry, 1970-1991*. The purpose of this report is to provide a comprehensive overview of the ownership of the U.S. electric power industry over the past two decades, with emphasis on the major changes that have occurred, their causes, and their effects.

The legislation that created the EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions. The EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decisionmakers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

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Executive Summary

In 1970, electric utilities supplied 93 percent of the electricity generated in the United States. The balance was produced by "nonutilities"—generators of electric power that are not utilities—consisting primarily of industrial manufacturers that produced electricity for their own use. The electric utility's share of electric power generation increased steadily between then and 1979, when it reached 97 percent. The trend reversed itself in the 1980's, and by 1991 the electric utility's share declined to 91 percent. The legislative and regulatory changes that made the growth of nonutilities possible were:

- The Public Utility Regulatory Policies Act of 1978 (PURPA), which encouraged nonutilities to begin rapidly enlarging their small portion of electricity generation by guaranteeing a market for the electricity they produced and by exempting them from previous legislative restrictions, and

- More stringent regulatory review of utility costs by State regulators in the 1980's, which in some cases made utilities reluctant to build new electricity generating capacity and made State regulators more receptive to nonutility sources of supply.

The two changes were the culmination of several economic and technological changes that began occurring as early as the 1960's, including:

- Rapidly increasing costs to utilities of generating electricity resulting from increased fuel prices and increased construction and operating costs of generating plants, and

- Abruptly diminishing technological improvements to the basic process of generating electricity, which previously had been the source of decreases in the cost of generating electricity.

Increasingly, nonutilities are generating electricity not only for their own use but also for sale to electric utilities for distribution to final consumers. In 1991, nonutilities owned about 6 percent of the electric power generating capacity and produced about 9 percent of the total electricity generated in the United States.[1]

The reversal of the lack of growth in nonutility generating capacity during the 1980's is most strikingly illustrated by comparing the net increase (adjusting total additions for retirements) in generating capacity for utilities and nonutilities in recent years (Figure ES1). While most of the existing capacity, and during the 1970's, most of the additions to capacity, have been built by electric utilities, their share of capacity additions has declined in recent years. As recently as 1986, 80 percent of the net additions to total electricity generating capacity were added by utilities. In 1989, however, the utility share of net capacity additions was just over 50 percent, and in 1990 and 1991 nonutilities provided more than half of the net capacity additions.

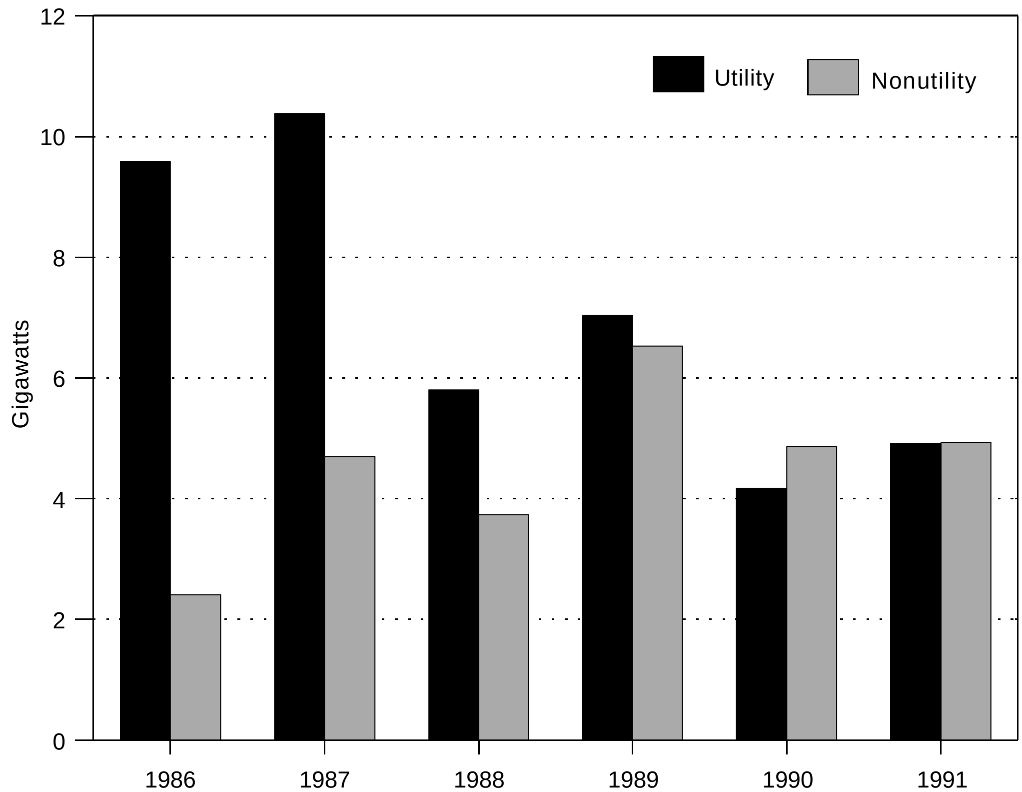
Nonutilities consist of "qualifying facilities" as defined in PURPA and "nonqualifying facilities."[2] Qualifying facilities have a unique advantage, because PURPA requires utilities to purchase all electricity offered for sale by these nonutility generators. Most existing nonutility capacity—75 percent—is classified as a qualifying facility. Nonutilities plan to add 15.4 gigawatts of capacity between 1992 and 1996, which is one-third of their actual 1991 capacity; the split between qualified and nonqualified facilities is planned to remain the same at 3 to 1.

About one-half of the current nonutility capacity is located in the West South Central Census Division, particularly in Texas, and the Pacific Contiguous Census Division, particularly in California. Most nonutilities in Texas, which produced 49 billion kilo-kilowatthours of electricity in 1991, are engaged in

[1]Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), p. 21.

[2]Qualifying facilities are nonutilities that meet the requirements specified by PURPA. The requirements include that the facility generate electricity using a technology which either sequentially produces electric energy and another form of useful energy (such as heat or steam) using the same fuel source (cogeneration) or uses renewable energy as a fuel source. In addition, qualifying facilities must meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission. Nonqualifying facilities are nonutilities that do not meet these requirements.

Figure ES1. Net Increases in Nameplate Capacity for Utilities and Nonutilities, 1986-1991



Notes: •Nameplate capacity is used instead of net summer capability because net summer capability is not collected for nonutilities. •The net increase in nameplate capacity has been adjusted for retirements. •Data shown in Tables C6 and C7.

Source: **Utility Capacity:** *1985-1991*—Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095 (Washington, DC, 1986 through 1992). **Nonutility Capacity:** *1985-1990*—Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1991* (Washington, DC, October 1992), p. 7. *1991*—Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), p. 2.

chemical manufacturing, which provides many opportunities for generating electricity along with another form of energy (such as heat or steam). In California, which produced 53 billion kilowatthours in 1991, most nonutilities are engaged primarily in electricity generation.

In 1991, nonutilities produced 49 percent of their electricity from natural-gas-fired boilers, much more than from any other single primary energy source. In con-trast, utilities produce the majority of their electricity by burning coal, and their second major source of energy is nuclear power. Renewable energy sources, except for hydroelectric power, are virtually untapped by electric utilities, while renewable fuels (including wood and waste) collectively produced the second largest share (34 percent) of nonutility electricity. One reason for the difference is that the majority of nonutility capacity is in the manufacturing sector of the economy, particularly in the chemical and paper industries. Both industries produce wastes as byproducts of the manufacturing process that can be used as a source of energy to drive electricity generators. Also, paper manufacturing uses a renewable fuel (wood) as a raw material in producing paper, making wood and wood waste easily accessible to paper manufacturers as an energy source for electricity generation.

The process of change in the structure of the electric power industry has not yet run its course, but several issues have already been raised. Major issues include the effect of the changing industry structure on the reliability of electric power supply and on bulk (wholesale) power trade. Also at issue is whether the Clean Air Act Amendments of 1990 will alter the course of nonutility growth.

The electric power generation, transmission, and distribution network is a complex system, requiring constant monitoring and adjustment. There is concern in the utility industry that the addition of many nonutility generators to the system may make it harder to control or even destabilize it. There is also concern that the transmission system is just not adequate to handle the increased wholesale trade. These concerns appear to be unwarranted. As long as certain technical requirements are met by the additional nonutility generating facili-ties, it should be possible for the electric power system to accommodate them without any decrease in its reliability.

The concern with the Clean Air Act Amendments of 1990 centers on whether nonutilities will be able to obtain a sufficient number of emission allowances to operate in compliance with the Amendments. Beginning in 2000 (with an incremental phase for utilities beginning in 1995), the Amendments require virtually all suppliers of wholesale electric power to obtain emission allowances for any sulfur dioxide released into the atmosphere. Utilities have been allocated most of these allowances. Nonutilities must obtain the allowances they need from utilities or from a sale or auction administered by the Federal Government. Allowances should be available to nonutilities, but there have not yet been enough trades to resolve their price.

Finally, the recently enacted Energy Policy Act of 1992 and the Federal Energy Regulatory Commission (FERC) rulemakings that will result from it, particularly on transmission access, deserve special note. The Act is one of the most important energy bills of recent times, particularly with respect to electric power. It contains provisions for reforming the Public Utility Holding Company Act. These new provisions loosen considerably the constraints on nonutilities entering the electricity generation industry and give FERC much broader authority to require utilities owning electric power transmission facilities to provide for nonutilities and other utilities access to their transmission systems. FERC rulemakings will implement this legislation, and the outcome of those rulemakings could have substantial effects on the direction and magnitude of future changes in the industry.

Nonutility generation from waste sources almost doubled from 1985 to 1991, accounting for 8 percent of national nonutility generation in 1991. At the Baltimore Refuse Energy Systems Company in Baltimore, Maryland, 85 percent of the city's garbage is burned to make energy.

1. Introduction

Electric power has been a critical commodity in the United States since early in this century and is essential for much of the Nation's economic growth. The industry is composed of both electric utilities and nonutilities. Prior to 1980, nonutilities primarily consisted of industrial manufacturers that produced electricity for their own use. Currently nonutilities not only consist of industrial manufacturers, but also other industrial groups that provide electricity and other services for their own use and/or for sale to others. The relative participation of utilities and nonutilities in the production of electricity in the United States has changed substantially over the history of the electric power industry.

This report presents data and describes how the structure of the electric power industry changed from 1970 through 1991. It then examines the causes of the changes and finally discusses the implications of the changing structure on the future of the electric power industry. Chapter 2 shows the types of ownership in 1991 in the U.S. electric utility industry, that is, investor-owned utilities, public and Federal utilities, and cooperative utilities, by shares of nameplate capacity. Nonutility electricity generating capacity is described by type of facility and by major industry ownership group for 1991. The changing patterns of utility and nonutility-owned electricity generating capacity is shown at the national level along with nonutility grid-serving and self-serving generation. Shares of nonutility-owned generating capacity are examined by Census Division, electricity generation by State, and by industry within major producing States. Changing patterns of fuel use include a description of utility electricity generation by energy source for 1970 through 1991 and nonutilities for 1985 through 1991. There is a comparison of relative fuel prices for utility and nonutility generation for petroleum, natural gas, and coal for 1970 through 1990. Finally, a discussion of the finances of nonutilities is presented.

Chapter 3 includes a discussion of the Federal legis-lation and Federal and State regulation changes that encouraged nonutility growth and that will affect growth in the future. Among the legislation discussed are the Public Utility Regulatory Policies Act of 1978 (PURPA), the Energy Tax Act of 1978, the Clean Air Act Amendments of 1990, and the Energy Policy Act of 1992 (EPACT). A discussion of State regulation of the investor-owned electric utilities for the sale of electricity to retail customers follows. In addition, the basis for Federal involvement in the regulation of wholesale electric power transactions, found in the Federal Power Act, PURPA, and EPACT, is examined.

Chapter 4 describes the economic and technological factors that stimulated the legislative and regulatory changes. The sharp rise in the cost of generating electric power in the 1970's and early 1980's included an

Because of facilities such as Wisconsin Electric Power's Point Beach Nuclear Units 1 and 2, rated at 495 megawatts each, nuclear generation by utilities increased from 22 billion kilowatthours in 1970 to 613 billion kilowatthours in 1991. By 1991, uranium was the second largest energy source used in generating electricity.

abrupt increase in the price of fossil fuels and increases in generation plant construction and operating costs. These changes increased the cost of producing electricity and resulted in legislative and regulatory change. The ending of improvements in thermal efficiency in electric power generation in the mid-1960's intensified the increase in generating costs. The average capacity of utility-owned coal-fired steam units (historical and planned) from 1970 to 2000 is compared with non-utility-owned steam turbine units (conventional and fluidized bed), combustion turbines, and wind turbines (historical and planned) from 1970 to 1995.

Chapter 5 examines the 5-year plans for new capacity additions for utilities and nonutilities from 1992 through 1996. Planned capacity additions are also described by prime mover and, for nonutilities, by type of facility. The growing share of nonutility capacity poses a challenge to the reliability of the electric transmission system. The steps utilities have taken to ensure reliability are discussed, including contract terms with nonutilities. The North American Electric Reliability Council guidelines to ensure reliability for both utilities and nonutilities are described. Bulk power (wholesale) trade and transmission capacity issues related to increased use by nonutilities are discussed.

Extensive data on electric utilities and their operations have been collected by the Energy Information Administration (EIA) for many years, since they are either regulated or owned by government entities. However, data on nonutilities that generate electricity are more limited in the type of data collected and the years in which data were collected. Because of these data limitations for nonutilities, this report compiled data from several different sources. Although several sources are used, there still exist a few years for which no data are available. In addition, the tables and figures in the report always provide a specific source reference (See Box).

Data Sources

For several decades before 1979, production of electricity by nonutilities was a small and diminishing segment of the electric power industry. Before then, data were collected by the EIA for most electric power plants, both utility and nonutility, the latter with an nameplate capacity of 10 megawatts or more, on the Federal Power Commission (FPC) Form 4, “Monthly Power Plant Report.” Data from industrial power plants were no longer collected on this form after 1979, and submissions by other nonutility power plants, counted as utilities at the time, were eliminated in the mid-1980's. The Edison Electric Institute (EEI), however, has prepared estimates of industrial generating capacity and production for 1980 through 1984. The EEI began collecting data for all types of nonutilities in 1985, and in 1989 the EIA again began collecting data for nonutility generating facilities with an installed capacity of 1 megawatt or more (every 3 years) and 5 megawatts or more (every year) on Form EIA-867, “Annual Nonutility Power Producer Report.” A copy of this form and its instructions are included in Appendix A. Data from Form EIA-867 for nonutility generating facilities of 5 megawatts of capacity or more are presented in this report for 1991. In 1991, 966 nonutility facilities, listed in Appendix B, responded to the EIA inquiry.

There was no comprehensive survey of nonutility capacity from 1980, when EIA interrupted its collection of data on industrial nonutilities, through 1985, when the EEI began its collection of data on nonutilities. Unfortunately, the EIA and EEI data are not strictly comparable. The nonutility data published by the EIA for the years prior to 1979 include only plants of 10 megawatts or more and only those at industrial facilities. Most of the nonutility data published by the EIA for the years beginning in 1989 include only nonutility facilities of 5 megawatts or more. Thus, the EIA sample is smaller than the EEI survey, which includes nonutilities at all types of enterprises and of all sizes. However, estimates of the aggregates of the data series suggest that differences among them are not large. Nameplate capacity at nonutility facilities other than industrial facilities totaled 2 percent of the total nonutility nameplate capacity for plants of 10 megawatts or more in 1979. According to the EEI data, the installed generating capacity at facilities with a capacity of less than 10 megawatts was 8 percent of the total nonutility capacity in 1991, and the installed capacity at plants with a capacity of less than 5 megawatts was 5 percent of total nonutility capacity.

2. Changes in Industry Structure, 1970-1991

Types of Ownership in the U.S. Electric Power Industry

The utility and nonutility segments of the electric power industry are predominantly owned by the private sector in the United States. However, a large number of utilities are owned by Government agencies or cooperatives. Utilities are split among approximately 270 private, investor-owned utilities, encompassing 77 percent of the production capacity of the utility industry, and 2,970 Government-owned and cooperatively owned utilities, with 23 percent of capacity (Figure 1). These utilities vary widely in size and organization.

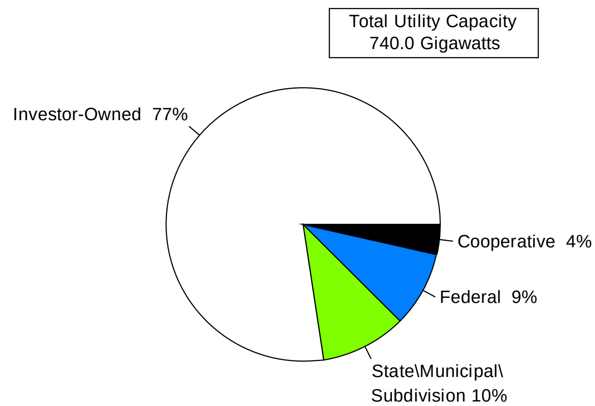
Investor-Owned Utilities

The electric utility industry is dominated by investor-owned utilities (IOUs), which are regulated by State and Federal regulatory agencies. The structure of the utility industry has evolved during this century from one composed of many small private and municipal electric power companies to large private utilities that integrate electricity production, transmission and distri-bution, and sales. These private utilities were created by the merger of many of these small companies or by their absorption by a private utility. This process continued with private systems consolidating into larger utilities, which were often combined into holding com-panies. These holding companies were either broken up or regulated by the Public Utility Holding Company Act of 1935 (PUHCA, Public Law 74-333).

IOUs share many common structural and regulatory characteristics. The typical IOU has traditionally gener-ated, transmitted, and distributed electricity. The utility usually has an exclusive franchise to provide service to retail customers within its service territory; it also has the obligation to provide reliable electric power to anyone within its service territory and the privilege of regulated prices that earn it a fair rate of return on its investment.

In recent years the operation of IOUs has been changing in fundamental ways. IOUs have become more involved, than they were historically, in transporting electricity between other utilities, “wheeling,” in the wholesale market. Because of the unexpected sharp drop in the growth of electricity demand in the mid-1970's, some utilities have been left with large amounts of excess generating capacity, which was originally built for their own service territories. In addition, utilities are purchasing proportionally more electricity from nonutilities.

Figure 1. Shares of Nameplate Capacity at Utilities by Class of Ownership, 1991



Notes: •Nameplate capacity is used instead of net summer capa-bility because net summer capability is not collected for nonutilities. •The State\Municipal\Subdivision category includes utilities owned by States, municipalities, and other political subdivisions (i.e., districts or public agencies within a State that are engaged in the sale, exchange, and/or transmission of electricity). •Data shown in Table C1.

Source: Energy Information Administration, Form EIA-860, “Annual Electric Generator Report” (1991).

Public, Federal, and Cooperative Utilities

By 1991, utilities owned by States, municipalities, and other political subdivisions accounted for 10 percent of total U.S. utility industry generating capacity, Federal utilities accounted for 9 percent, and cooperatives accounted for 4 percent. Many of these utilities began developing in the 1930's, when the Federal Government joined the electric power industry as a wholesale supplier, mainly through the development of large hydroelectric sites. Federal participation spurred the growth of other publicly and cooperatively owned utilities by offering them the preferential sale of lower priced federally generated power, as did Federal low-interest loans and other technical assistance. During and after World War II, Federal and public power participation in wholesale electricity markets continued to increase as generating capacity built for the war effort was redirected to the production of power for sale to utilities and large industrial companies.[1] The Federal share of total generation reached its peak soon thereafter, but cooperatives, public and municipal power districts, and State projects continued to grow rapidly.

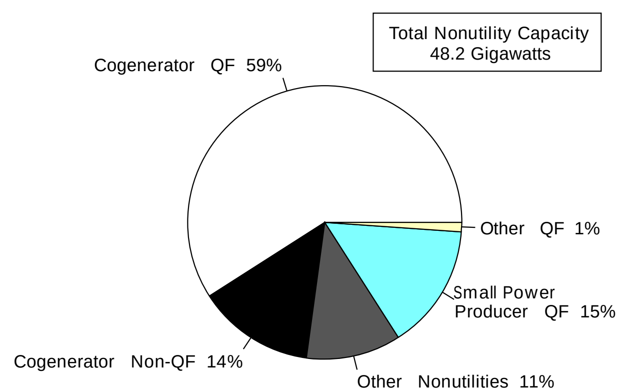
The 6,494-megawatt Grand Coulee Dam is only one of many hydroelectric sites owned by the Federal Government. The Federal Government's primary expansion of hydroelectric sites began in the 1930's, when these facilities became a major wholesale supplier of electricity.

Nonutility Generators

There are two broad categories of nonutility electric generating facilities: qualifying and nonqualifying facilities. Qualifying facilities were defined by the provisions of the Public Utilities Regulatory Policies Act (PURPA, Public Law 95-617). PURPA, signed into law in November 1978, required electric utilities to interconnect with and purchase power from any facility meeting the criteria for a qualifying facility (QF) under the Act. Two types of QFs were recognized: cogenerators, which sequentially produce electric energy and another form of energy (such as heat or steam) using the same fuel source, and small power producers, which use waste, renewable energy, or geothermal energy as a primary energy source. These nonutility generators are "qualified" under PURPA, in that they meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC), as discussed later in Chapter 3. In 1991, cogenerator Qfs accounted for 59 percent of U.S. nonutility electricity generating capacity, and small power producers accounted for 15 percent (Figure 2).

Other nonutility electricity generators, which are not certified as meeting the FERC criteria for QFs under PURPA (a plant that produces only electric energy), constitute a much smaller proportion of the industry than QFs. In 1991, non-QFs accounted for only 25 percent of total nonutility electricity generating capacity (Figure 2). Most of this capacity was owned by non-QF cogenerators (14 percent of the total); many of these are industrial cogenerators which consume all of the electricity they cogenerate themselves and are thus indifferent to QF status. Other non-QF facilities (11 percent of total nonutility capacity in 1991) include industrial and commercial enterprises, which generate electricity for their own use, and independent power producers (IPPs), which generate electricity primarily for sale to others; neither of these types of nonutilities employ cogeneration technology.

Figure 2. Shares of Nameplate Capacity at Nonutilities by Type of Facility, 1991



Notes: •Data are preliminary. •Includes plants of 5 or more megawatts only. •Other QF capacity includes facilities that are both cogenerators *and* small power producers. •Data shown in Table C2.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

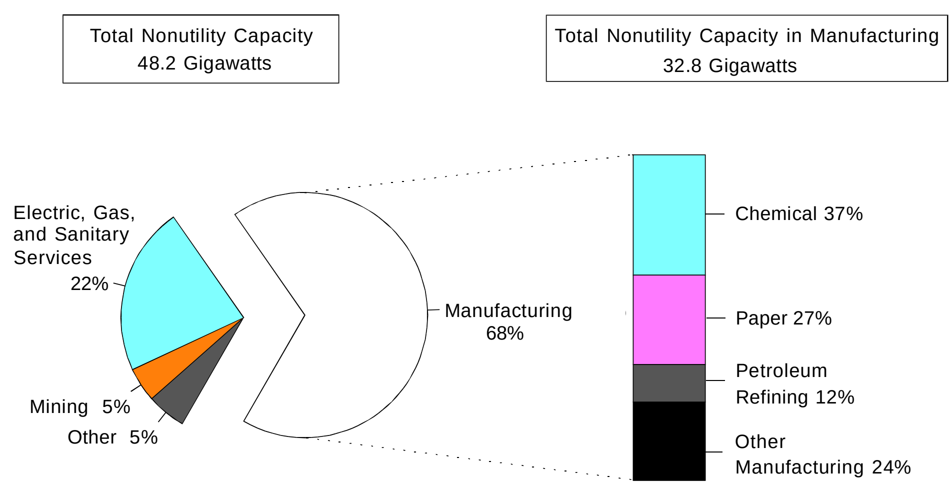
Cogeneration

Cogeneration technologies are classified as "topping-cycle" and "bottoming-cycle" systems. In a typical topping-cycle system, high-temperature, high-pressure steam from a boiler is used to drive a turbine to generate electricity. The waste heat or steam exhausted from the turbine is then used as a source of heat for an industrial or commercial process. In a typical bottoming-cycle system, high-temperature thermal energy is produced first for applications such as reheat furnaces, glass kilns, or aluminum metal furnaces, and heat is then extracted from the hot exhaust stream of the primary application and used to drive a turbine. Bottoming-cycle systems are generally used in industrial processes that require very high-temperature heat.

Cogenerators, both QF and non-QF, accounted for nearly three-quarters of total nonutility electricity generating capacity in 1991 (Figure 2). The primary energy source is generally a fossil fuel (coal, petroleum, or natural gas), although renewable energy sources are also used, particularly wood and waste.[2]

Nonutility electricity generators are found in many different industries. Most nonutility generating capacity (68 percent) is in the manufacturing sector of the economy (Figure 3). Within the manufacturing sector, the chemical industry, with 37 percent of the manufac-turing total, the paper industry, with 27 percent, and petroleum refining, with 12 percent, have included more electricity generating facilities in their plants than other manufacturing sectors. The manufacturing processes conducted at many of these plants are conducive to cogenerating electricity. Next to manufacturing, the largest portion of nonutility electricity generating capacity (22 percent) can be found in the Electric, Gas, and Sanitary Services sector (Figure 3). The entities that make up this sector are usually engaged primarily in

Figure 3. Shares of Nameplate Capacity at Nonutilities by Major Industry Group, 1991



Notes: •Data are preliminary. •Includes plants of 5 or more megawatts only. •The classification system used is the Standard Industrial Classification (SIC). •Data shown in Table C2.
Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

[2]Cogeneration is not always economically efficient, even though it may use energy more efficiently. Thus, while cogeneration may conserve energy resources, it may waste total resources. See Paul L. Joskow and Donald R. Jones, "The Simple Economics of Industrial Cogeneration," *The Energy Journal*, vol. 4, no. 1 (1983), pp. 1-22.

Cogenerators comprise 73 percent of all nonutilities. The Kern River Cogeneration Company, one of California's largest cogeneration facilities, produces steam to help recover oil and generates electricity to sell to Southern California Edison.

producing, transporting and/or distributing electricity, although they may be engaged primarily in steam, gas, water, and/or waste disposal services as a primary business. Unlike nonutilities in the other sectors, these nonutilities are engaged primarily in activities similar to those carried out by electric utilities. The remaining nonutility capacity is found in either the mining industry (5 percent) or in various other industries, including agriculture, transportation, and other services (5 percent).

Changing Patterns of Ownership

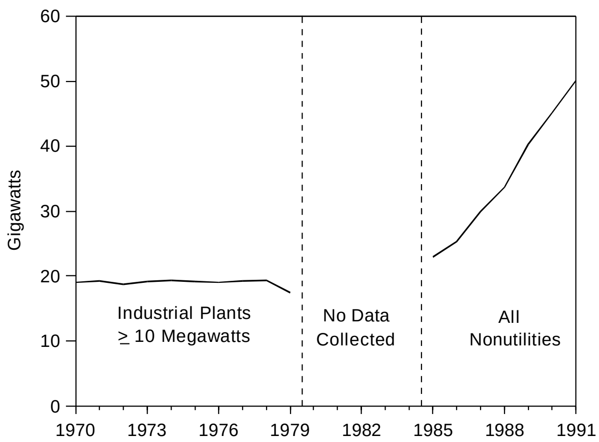
National Trends

Throughout the 1970's, nonutility-owned electricity generating capacity in the United States totalled approximately 19 gigawatts, the majority of which was cogeneration capacity owned by industrial companies, providing electricity largely for their own use. The amount of nonutility capacity changed very little between 1970 and 1979 (Figure 4). In contrast, utility-owned capacity increased by an average rate of just over 6 percent per year during the same period, from 342 gigawatts in 1970 to 598 gigawatts in 1979 (Figure 5). Thus, the nonutility share of capacity declined steadily. This decline was reversed by the second half of the 1980's, however, when nonutility capacity was growing rapidly, largely as the result of the specifications in PURPA and the economic, regulatory, and technological factors that lead to its passage. During this time the growth of utility capacity slowed down. Between 1985 and 1991, the annual growth rate for utility capacity was only 1.0 percent, whereas nonutility capacity grew by 13.9 percent annually, increasing by almost 120 percent in 6 years. Although nonutilities still accounted for only 6 percent of the total in 1991, they added more net capacity (after adjustment for retire-ments) during 1990 and 1991 than did utilities, suggesting a reemergence of nonutilities as important producers of electricity.[3]

Nonutility electricity generation has increased even faster than capacity, increasing from 98 billion kilowatthours in 1986 to 275 billion kilowatthours in 1991, an average annual growth rate of 19 percent. Also during that period, nonutility generation increasingly has been sold and not consumed by the generating company. In 1985, 71 percent of nonutility generation was for use by the nonutility itself and not for sale. By 1991, only 50 percent of the nonutility generation was for their own use. In the 1980's, numerous nonutility facilities began generating electricity to be sold to utilities, and nonutility sales to utilities increased from 28 billion kilowatthours in 1985 to 137 billion kilo-watthours in 1991, an annual average growth rate of 30 percent. During the same period, nonutility generation

[3]Paul Joskow argues that the growth in wholesale electricity trade, especially the development of nonutility power producers, was probably the most important response to the changes of the 1970's and 1980's. See Paul L. Joskow, "Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry," *Brookings Papers on Economic Activity: Microeconomics* (1989), pp. 126-128.

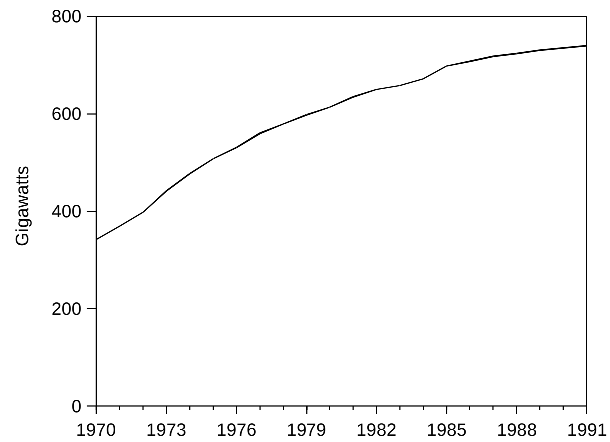
Figure 4. Nonutility Nameplate Capacity, 1970-1979, 1985-1991



Notes: •Data for 1970 through 1979 represent capacity in the industrial sector for plants of 10 megawatts or more only. •Data were not collected for 1980 through 1984. •Data for 1985 through 1991 include all nonutilities. •Data shown in Table C7.

Source: **1970-1979:** Federal Power Commission, Form 4, "Monthly Power Plant Report." **1985-1990:** Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1991* (Washington, DC, October 1992), p. 7. **1991:** Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), p. 2.

Figure 5. Utility Nameplate Capacity, 1970-1991



Notes: •Nameplate capacity is used instead of net summer capability because net summer capability is not collected for nonutilities. •Data shown in Table C6.

Source: **1970-1981:** Energy Information Administration, *1982 Annual Energy Review*, DOE/EIA-0384(82) (Washington, DC, April 1983), p. 159. **1982-1991:** Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095 (Washington, DC, 1984 through 1992).

for self use increased from 70 billion kilowatthours to 139 billion kilowatthours (Figure 6). The causes for this change are discussed in more detail in Chapters 3 and 4.

In 1979, electric utilities supplied 97 percent of the total electricity generated. While electric utilities remain the principal producers of electricity in the United States, the nonutility share of total electricity generation reached almost 9 percent in 1991 (Figure 7). Current Energy Information Administration projections show nonutility generation continuing to increase, reaching 332 billion kilowatthours by 1995 and accounting for 10 percent of total U.S. generation that year.[4] This projection is based mostly on planned capacity additions already announced by utilities and nonutilities.

Regional Trends

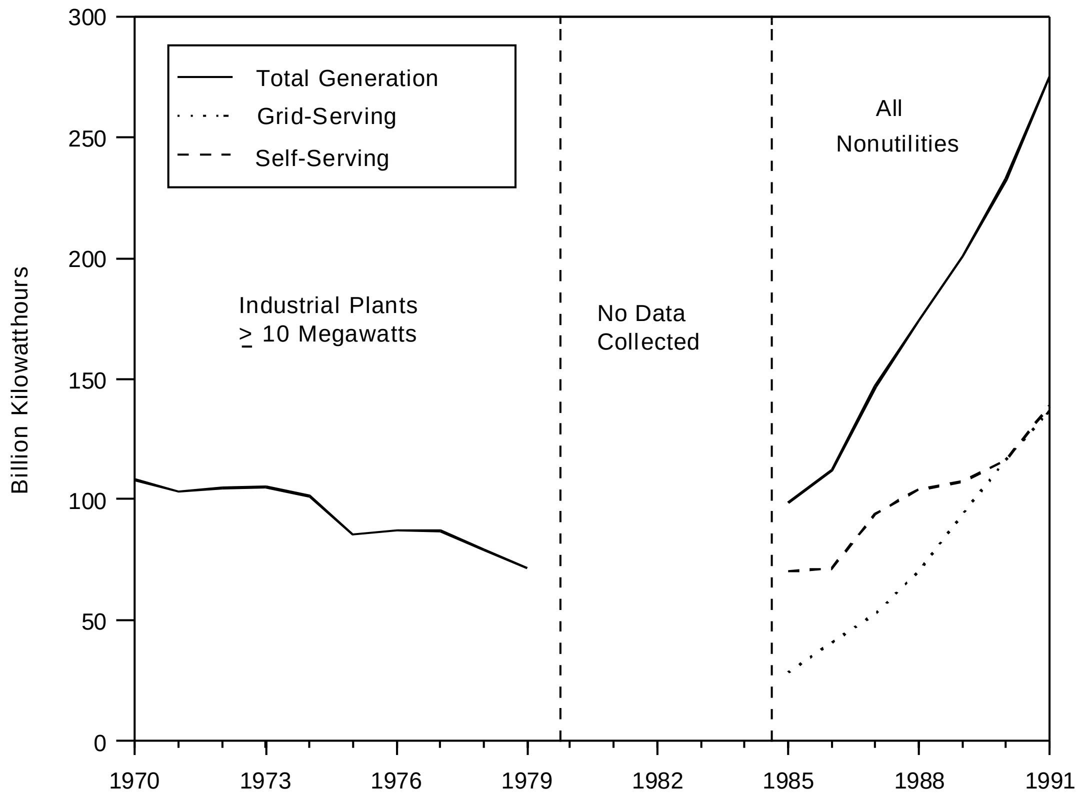
Nonutility-owned electricity generating capacity varies widely across the 10 U.S. Census Divisions (Figure 8). The region with the most nonutility capacity is the West South Central Region, where many large petroleum refineries and chemical manufacturers operate. The production processes in these two industries provide excellent opportunities for cogeneration, and 83 percent of the nonutilities in the region are QFs.

The Pacific Contiguous Region also contains many qualifying nonutility facilities. The California Energy Commission has encouraged nonutility development. In particular, the "avoided cost" for QFs in California was originally quite high because of the high oil and gas prices paid by electric utilities in the late 1970's and early 1980's.

California and Texas together accounted for 41 percent of the Nation's nonutility electricity production in 1991, with 53 and 49 billion kilowatthours, respectively. Eight other States had nonutility generation greater than 6 billion kilowatthours (Figure 9), and together with Texas and California they accounted for 65 percent of the total U.S. nonutility output.

[4]Energy Information Administration, *Annual Energy Outlook 1993*, DOE/EIA-0383(93) (Washington, DC, January 1993), Table A4 (Reference Case).

Figure 6. Nonutility Grid-Serving and Self-Serving Electricity Generation, 1985-1991, and Total Nonutility Electricity Generation, 1970-1979, 1985-1991



Notes: •Data for 1970 through 1979 represent capacity in the industrial sector for plants of 10 megawatts or more only. •Data were not collected for 1980 through 1984. •Data for 1985 through 1991 include all nonutilities. •Data shown in Table C7.

Source: **1970-1979:** Federal Power Commission, Form 4, "Monthly Power Plant Report." **1985-1990:** Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1991* (Washington, DC, October 1992), p. 15. **1991:** Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), pp. 2 and 31.

Most of the nonutility facilities in California produce electricity for sale to electric utilities. In 1991, 22.6 billion kilowatthours of the State's total nonutility electricity generation was produced by the Electric, Gas, and Sanitary Services sector. The Mining sector accounted for 8.9 billion kilowatthours and Petroleum, 7.0 billion kilowatthours (Figure 10).

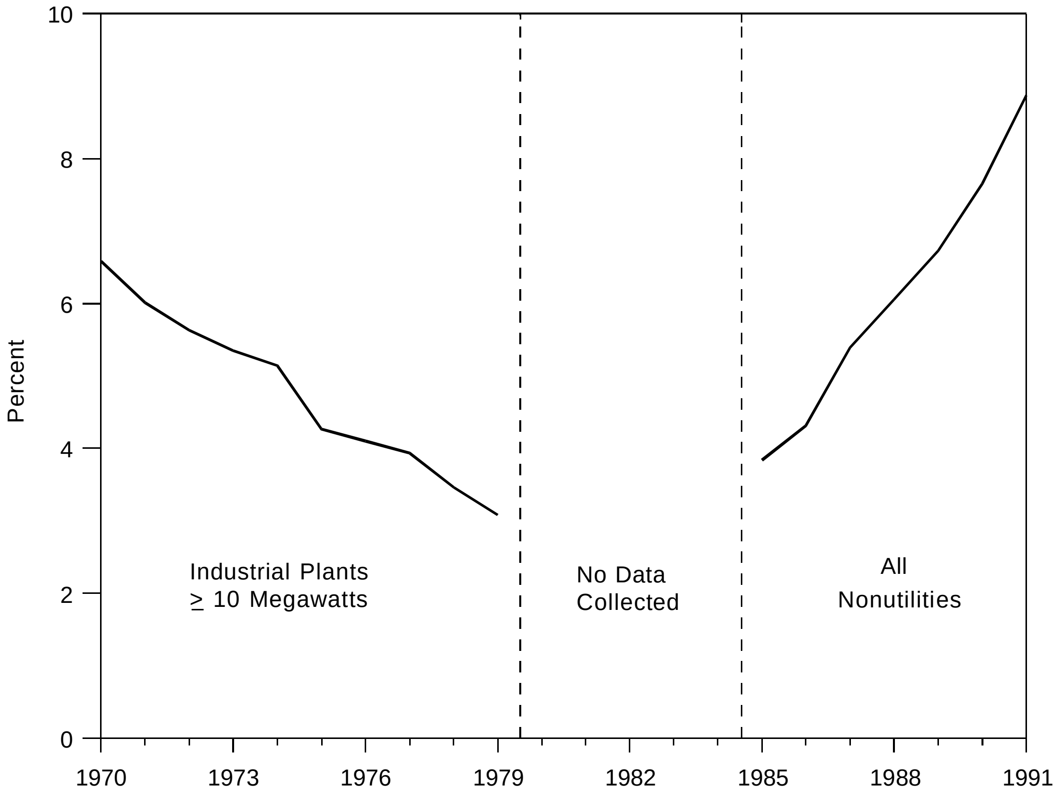
Although more than half of California's nonutility electricity production in 1991 was from natural gas, many of the nonutility facilities in the State are fueled by renewables. In the late 1980's, the State passed tax incentives[5] encouraging new facilities to use renewable sources. Production from geothermal, solar, and wind resources by nonutilities in California totaled almost 10 billion kilowatthours in 1991, 87 percent of the Nation's total nonutility production from these sources.

In Texas, the Chemical Manufacturing sector produced the largest share of the State's nonutility generation—29 billion kilowatthours in 1991. Nonutility production in the Petroleum Manufacturing sector was a distant second at 9 billion kilowatthours. Most of the nonutility generation in Texas is from burning natural gas as a fuel. There are also some coal-fired nonutility facilities in the State, but few that use renewable resources.

Although nonutilities in California and Texas produced more electricity than those in other States in 1991, nonutility generation was a larger share of total electricity production in some other States with smaller total production (Figure 11). Whereas nonutility production was 34 percent of the total in California and 17 percent in Texas, virtually all of the electricity produced in Rhode Island was generated by one

[5] California Code of Regulations, "Solar Electric Tax Credit," Title 20, Chapter 8, Article 1 (July 1991).

Figure 7. Nonutility Share of Total Electricity Generation, 1970-1979, 1985-1991

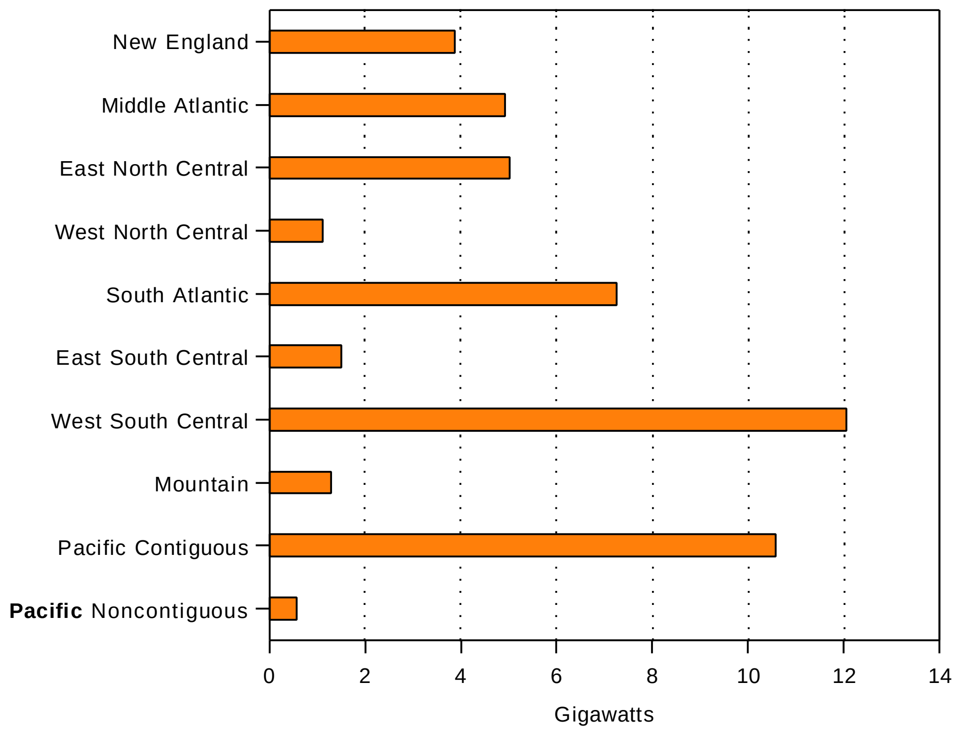


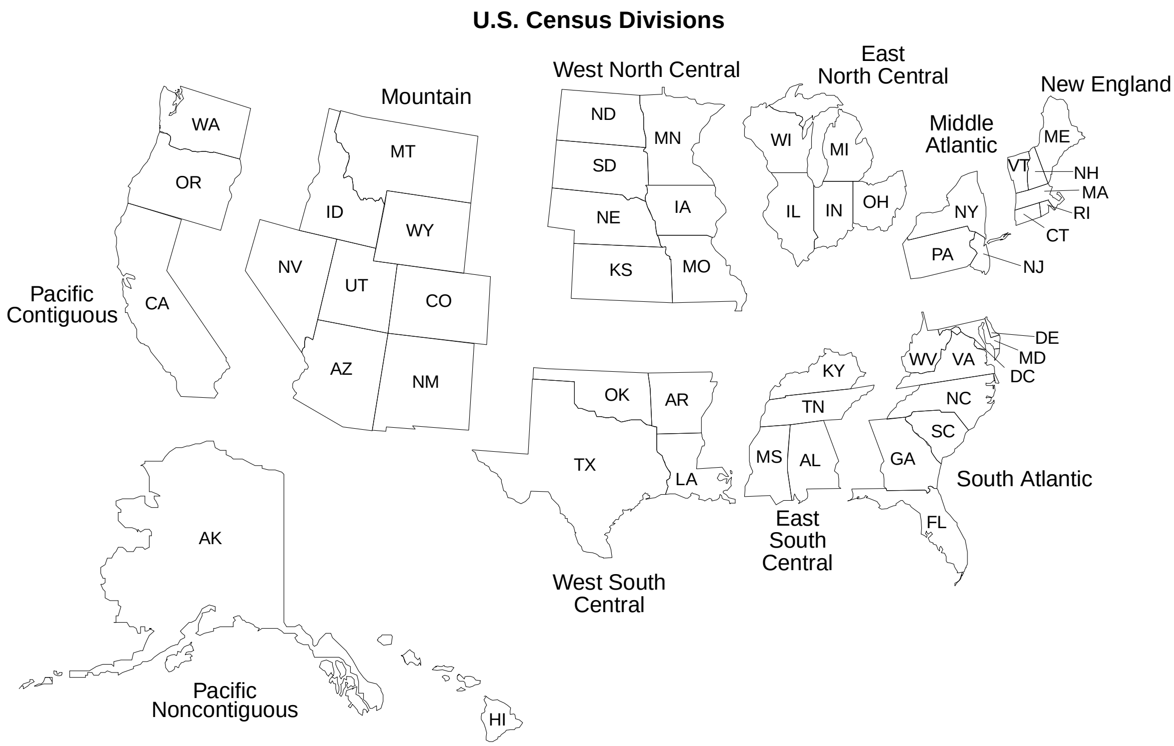
Notes: •Nonutility generation includes self generation and sales to the grid. •Nonutility data for 1970 through 1979 represent capacity in the industrial sector for plants of 10 megawatts or more only. •Nonutility data were not collected for 1980 through 1984. •Nonutility data for 1985 through 1991 include all nonutilities. •Data shown in Tables C6 and C7.

Source: **Utility Generation:** *1970-1990*—Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC, June 1992), p. 211. *1991*—Energy Information Administration, *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, DC, forthcoming), p. 30. **Nonutility Generation:** *1970-1979*—Federal Power Commission, Form 4, "Monthly Power Plant Report." *1985-1990*—Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1991* (Washington, DC, October 1992), p. 15. *1991*—Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), p. 2.

Some industrial nonutilities generate electricity for self-use. EXXON's Baytown facilities in Texas are involved in crude oil processing and chemical manufacturing, as well as generating electricity for their own use.

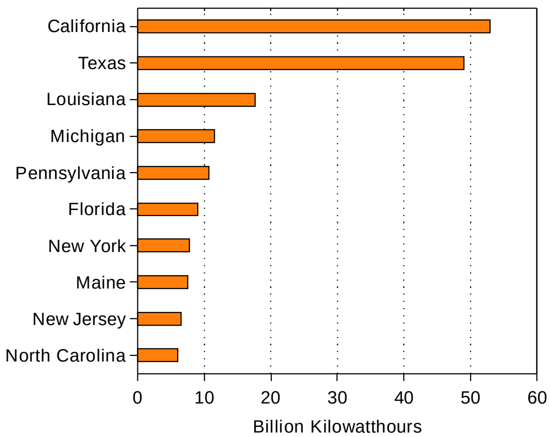
Figure 8. Nonutility Nameplate Capacity by Census Division, 1991





Notes: •Data are preliminary. •Includes plants of 5 or more megawatts only. •Data shown in Table C4.
Source: **Nonutility Data:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991). **Census Divisions:** United States Bureau of the Census.

Figure 9. Nonutility Electricity Generation by Largest Producing States, 1991



Notes: •Data are preliminary. •Includes plants of 5 or more megawatts only. •States listed are those with generation of 6 or more billion kilowatthours. •Data shown in Table C5.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

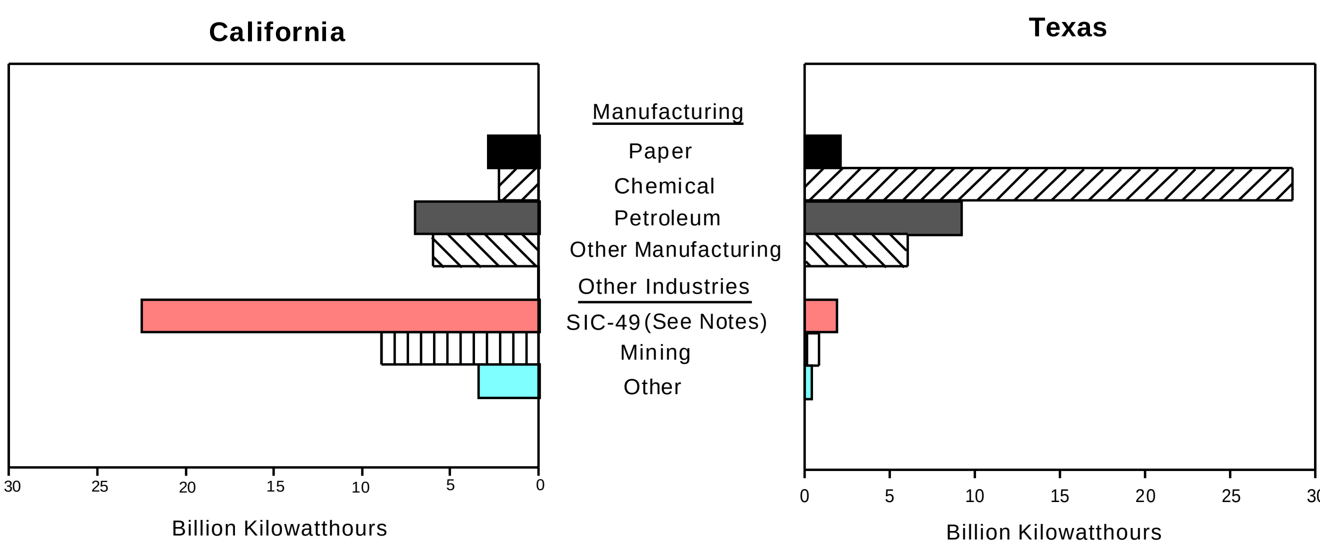
nonutility, Ocean State Power.[6] In Maine, nonutility electricity production—primarily in the Paper Manufacturing sector—accounted for 44 percent of the State's 13.8 billion kilowatthours of total electricity production in 1991. Another State with a large proportion of nonutility production was Louisiana, with 17.6 billion kilowatthours—24 percent of the State's total electricity generation of 74.7 billion kilowatthours. Alaska, a small producer at 5.2 billion kilowatthours, also produced proportionally more power from nonutilities—18 percent—than Texas.

Changing Patterns of Fuel Use

Utilities

Coal has been the fuel of choice in the electric utility industry for many years, providing 46 percent of the Nation's utility generation in 1970 and more than 50 percent since 1980. Historically oil-fired and gas-fired generation have also made up a large part of the Nation's electricity supply, but their share has been declining since the 1970's, when world oil prices escalated. Hydroelectric power also plays a large role.

Figure 10. Nonutility Electricity Generation by Major Industry Group in California and Texas, 1991

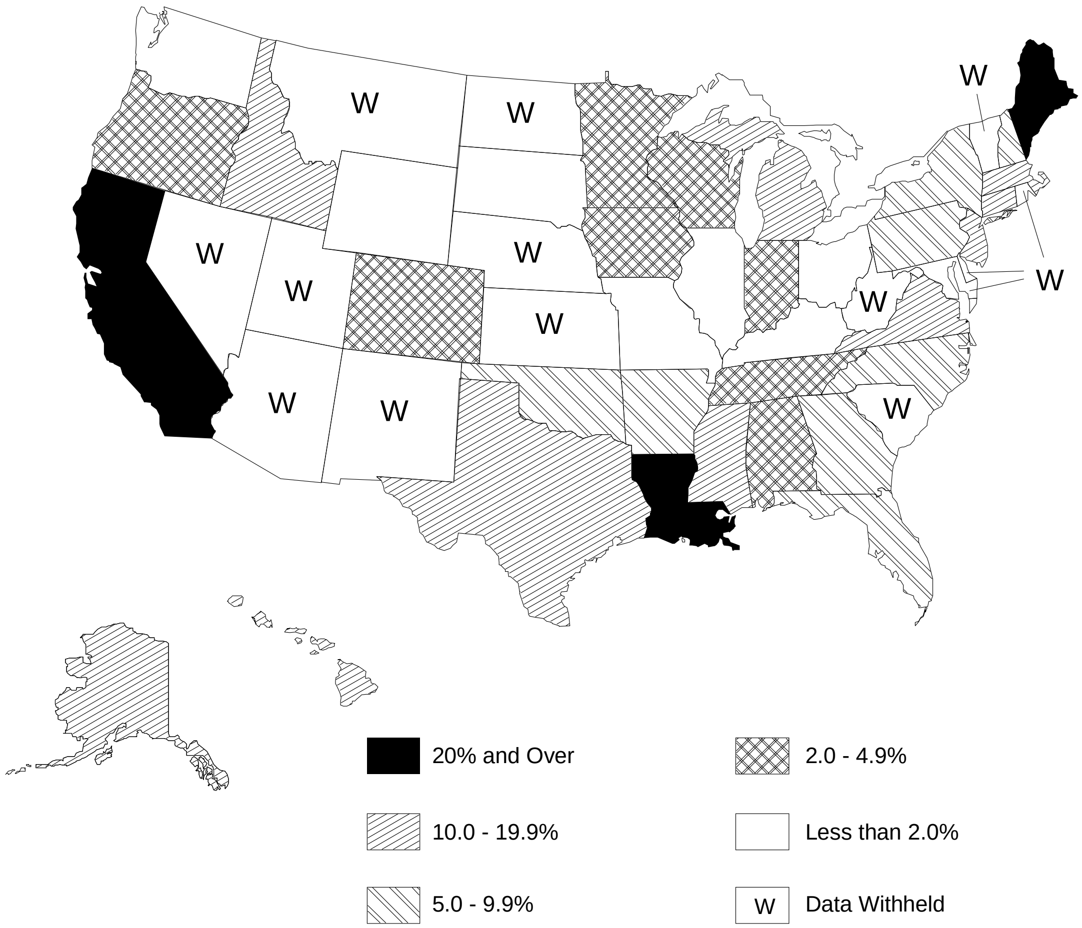


Notes: •Data are preliminary. •Includes plants of 5 or more megawatts only. •The classification system used is the Standard Industrial Classification (SIC). •SIC-49 includes establishments engaged in the generation, transmission, or distribution of electricity, gas, steam, water, or sanitary systems. •Data shown in Table C2.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

[6]The proportion of Rhode Island generation from nonutilities is withheld to avoid disclosure of individual company data.

Figure 11. Nonutility Electricity Generation by State as a Percentage of Each State's Total Electricity Generation, 1991



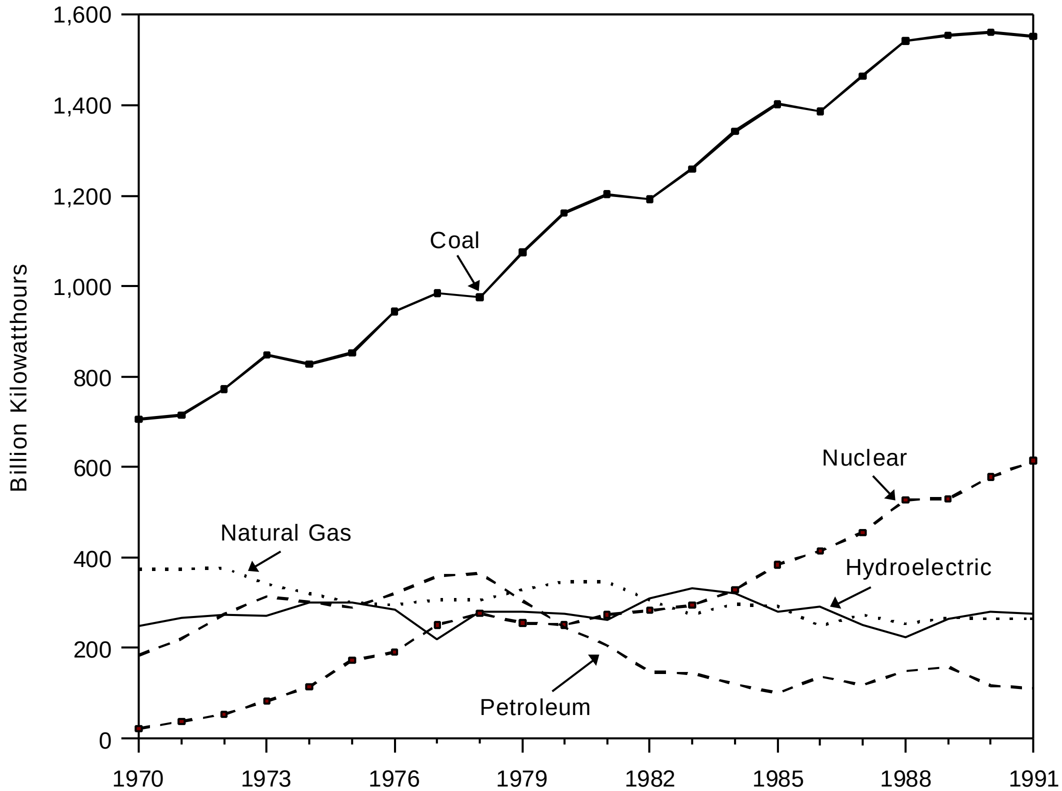
Notes: •Data are preliminary. •Nonutility generation from plants of 5 or more megawatts only. •Some State nonutility data have been withheld to avoid disclosure of individual company data; these States account for less than 5 percent of total United States nonutility generation. •Data shown in Table C5.

Source: **Utility Generation:** Energy Information Administration, *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, DC, forthcoming), p. 31. **Nonutility Generation:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

Nuclear power, which entered the picture in the 1960's, provided 1.4 percent of the Nation's utility electricity in 1970 and 22 percent in 1991 (Figure 12). Coal, which dominates utility generation, generally has been the least expensive fossil fuel per unit of energy yield[7] (Figure 13). In contrast, oil prices have been the highest and the most volatile of the fossil fuel prices over the past 20 years, and oil has declined from being, after coal, among the next three major sources of energy for electricity generation in the 1970's to being indisputably fifth in the 1980's. Moreover, considerable effort has gone into reducing the use of oil for national security reasons, because much of it is imported.

Nuclear power has gone from the smallest major source of energy for electricity generation to the second largest in the past two decades. This relative growth can be attributed to large nuclear power plant construction programs in the 1960's and 1970's, when nuclear power was expected to be a cheap and widely accepted source of electricity. However, electricity generated from uranium is expected to grow little over the next decade, largely because few plants are still under construction, and no new orders are expected to be completed before 2000.

Figure 12. Utility Electricity Generation by Energy Source, 1970-1991



Note: Data shown in Table C6.
Source: **1970-1990:** Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC, June 1992), p. 211. **1991:** Energy Information Administration, *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, DC, forthcoming), p. 14.

The amount of electricity generated from hydroelectric power by utilities has stayed relatively constant since 1970; consequently, its use has declined relative to the other major fuels. Hydroelectric power is mostly generated at large dam installations. The limited number of economically practical sites for conventional hydroelectric projects and the environmental impact of large dams have allowed few new prospects for notable expansion of conventional hydroelectric generation.[8]

Nonutilities

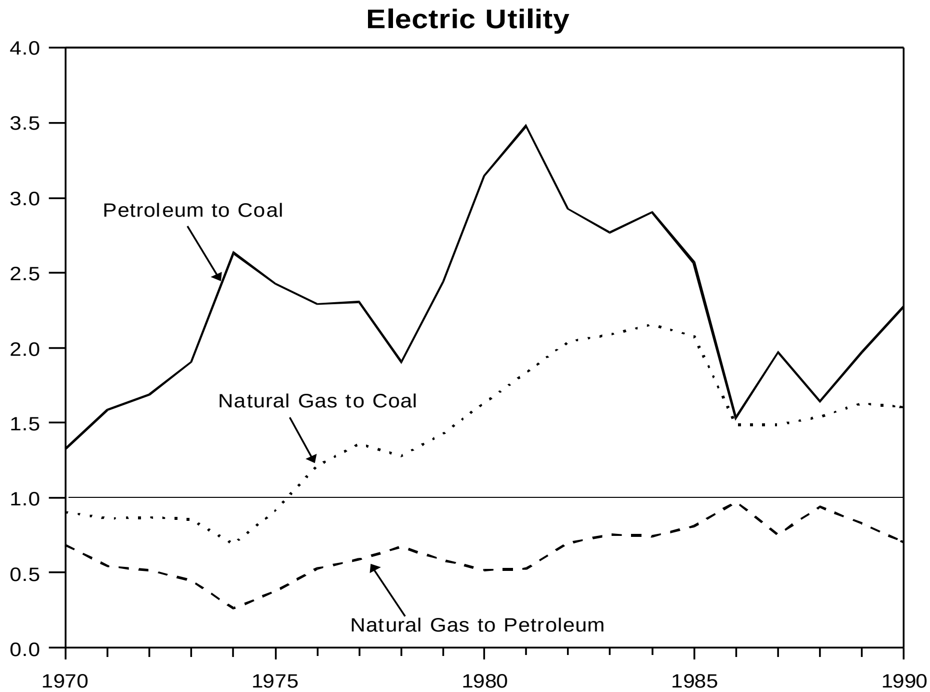
From 1985 through 1991, natural gas has increasingly been the major fuel used by nonutility electricity generators (Figure 14). In 1991, natural gas fueled half of all nonutility electricity generation. The other major fuels for nonutilities are renewable resources, coal, and waste. Electricity generation from renewable fuels and coal more than doubled between 1985 and 1991, while generation from waste almost doubled. Taken together, all renewable resources produced the second largest share of electricity—26 percent—from nonutilities in 1991.

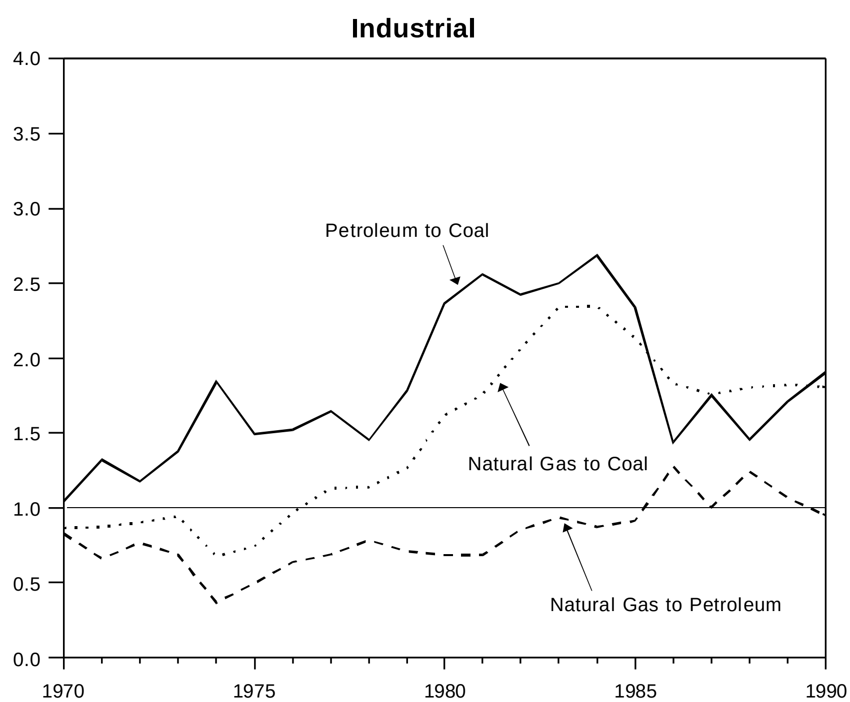
Financial Characteristics of Nonutilities

The lack of sufficient data makes it difficult to formulate generalizations based primarily on financial analysis of nonutilities. As discussed previously, there are two distinct classes of nonutility power producers:

[8]The last large conventional hydroelectric project began operating in 1967. Gross generation from pumped storage hydroelectric plants has increased, but their net generation is slightly negative. Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1990*, DOE/EIA-0455(90) (Washington, DC, June 1992), p. 33.

Figure 13. Relative Fossil Fuel Prices by Sector, 1970-1990

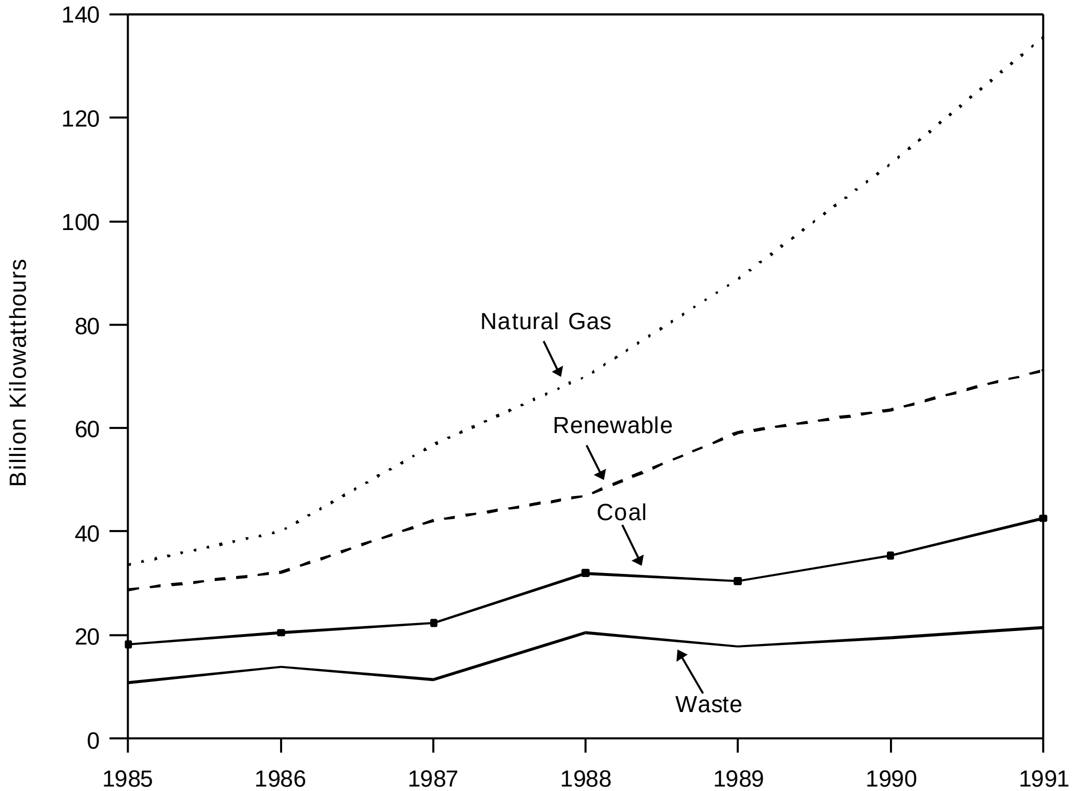




Notes: •In the Electric Utility Sector, the coal price is the price of all coal and the petroleum price is the price of heavy oil. (Heavy oil includes grade numbers 4, 5, and 6, and residual fuel oils). •In the Industrial Sector, the coal price is the price of steam coal and the petroleum price is the price of residual fuel oil. •Data shown in Tables C6 and C7.

Source: Energy Information Administration, State Energy Price and Expenditure Data System, 1992.

Figure 14. Nonutility Electricity Generation by Major Energy Source, 1985-1991



Notes: • Renewable energy sources include biomass, hydroelectric, wind, solar, and geothermal resources. Waste energy sources include anthracite culm, blast furnace gas, coke oven gas, digester gas, petroleum coke, refinery gas, refinery oil, sulfur combustion, waste gas, and waste heat. • Data shown in Table C7.

Source: **1985-1986:** Edison Electric Institute, *1986 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, July 1988), pp. 78 and 79. **1987-1988:** Edison Electric Institute, *1988 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, April 1990), pp. 55 and 56. **1989-1990:** Edison Electric Institute, *1990 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, December 1991), pp. 55 and 56. **1991:** Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), p. 55.

QFs (consisting of cogenerators and small power producers) and non-QFs (including cogenerators that are not QFs, independent power producers, and affiliated power producers owned by electric utilities). This heterogeneous makeup of nonutility power generators poses problems in data collection, consolidation, and analysis. FERC has received financial data from six independent power producers for 1991. These data were required only from non-QF's with rates regulated by FERC on the basis of cost rather than a competitive market rate, so they represent a limited and possibly biased source of information.

Many manufacturing enterprises (accounting for about 68 percent of nonutility installed generating capacity in 1991) require one or both energy forms (steam or heat and electric power) for their own use and market the surplus electricity they produce. As a result, the cost of such cogeneration plants (including capital costs) is invariably embedded in the overall cost of operating the industrial facility. These cogeneration facilities are part of integrated manufacturing processes. Thus it is difficult to separate the specific terms and conditions under which the cogenerating facilities were financed from those of the integrated manufacturing process.

The major participants in any nonutility project, QF and non-QF, are the project developers,[9] the project creditors and equity holders, equipment and other vendors, fuel suppliers, and the utility purchasing the power. These participants assume risks associated with their role in the completion and operation of the project. Cost overruns will have an impact on equity holders and possibly lenders by reducing profitability.

Generally the single most critical element for a nonutility project to get started is the contractual arrangement with a utility to sell its electricity.[10] This element may have the operational impact of diminishing the riskiness of a project if it guarantees a market for delivered power and, associated with it, a known cash flow for the project over its useful life. If the utility offers a guaranteed purchase contract to the nonutility, the utility assumes the demand or the market risk of the project, and the project owner (i.e., the nonutility) is left to manage the operating risk of successfully running the project to ensure delivery of power. In contrast, utilities carry both the risks inherent in starting new projects. Projected demand for power may fail to materialize—saddling the utility with excess capacity. There is also the danger that a utility may not be permitted to include all the costs in the ratebase because of prudence issues.

To structure project financing, the developers of nonutility projects often borrow as high a percentage of capital costs as possible, and the use of equity funds is pushed to the lowest possible level. Historically, nonutilities have often been able to finance projects with high debt / equity ratios, with the percentage of debt in the capital structure often ranging between 80 to 90 percent and with equity outlays being as little as 10 to 20 percent. Sale-leaseback agreements have also allowed for 100 percent debt financing once the nonutility plant becomes operational. In contrast, for the aggregate of major investor-owned utilities (IOUs), long-term debt as a percent of capitalization averaged below 50 percent during the 1986-1990 period.[11] In other words, utilities employ equity in the range of 50 percent or more in some cases.

There are valid reasons for nonutilities using a higher percentage of debt in comparison with equity. Overall, debt is cheaper because interest payments invariably can be deducted from income for tax purposes, as long as profits are greater than interest payments, thereby reducing the after-tax effective cost of capital acquisition. The overall weighted average cost of capital is thus usually pushed down as the share of debt in capitalization goes up.[12]

The potential advantage for nonutilities over utilities of highly leveraged project financing may, however, be partially offset by the higher cost of borrowing to nonutilities. When a utility undertakes a new project, all of its assets are often at risk, and even if the project fails to be included in the utility's ratebase, the lender has recourse to the other assets of the utility. In the case of nonutilities, most financing is done on a nonrecourse basis, and if the project fails, the lenders have only its specific assets as security. By their very nature, these assets tend to be immobile and have little value for any purpose other than their initial intended use. This is one reason why nonutilities may have to pay a higher interest rate than utilities in borrowing. For similar reasons, nonutilities may have to pay a higher rate of return on equity to attract capital.

If both these conditions hold, it is quite possible that the weighted average cost of capital for nonutilities may be either lower or higher than those confronting utilities generally. In fact, the attractiveness of project financing per se has prompted some to argue that non-utilities enjoy an unfair advantage in the cost of building new capacity because they can be highly leveraged. Others argue that lower nonutility power costs result not from any unfair advantage in financing but from the benefits of competition among nonutilities.[13]

Initial Financial Results

To develop some insight into the finances of nonutility plants, the five nonutilities which were required to submit financial data for 1991 on FERC Form-1, "Annual Report of Major Electric Utilities, Licensees and Others," were examined (Table 1). They are not publicly held companies but are operating nonutility subsidiaries of parent companies. The parent companies may be any type of organization, including utilities;

[10]Contract provisions are designed to cover multiple aspects of pricing power. Effective indexing provisions that influence the allocation of risk and return among the participants are also common. For further details, see "Effective Indexing Provisions," *Independent Energy* (January 1991), pp. 20-24.

[11]Energy Information Administration, *Financial Statistics of Major Investor-Owned Electric Utilities: 1991*, DOE / EIA-0437(91) / 1 (Washington, DC, January 1993), p. 22.

[12]In theory, it is possible to own a project financed 100 percent by debt. The use of equity is necessary to assure the lenders that they do not assume the totality of project risks and that the developers will not walk away if a project fails to perform well.

[13]See, Roger F. Naill and William C. Dudly, "IPP Leveraged Financing: Unfair Advantage?," *Public Utilities Fortnightly* (January 15, 1992), pp. 15-18.

Table 1. Financial Statistics for Selected Nonutility Power Producers, 1991

Company Name[a]	Terra Comfort	Ocean State	Catalyst	Nevada Sun-Peak	Entergy Power
Balance Sheet Items (million dollars):					
Net Electric Plant	10	217	526	78	149
Total Assets	10	256	647	83	160
Total Proprietary Capital	307	118	-8	18	-22
Total Long-Term Debt	291	115	636	64	173
Total Current Liabilities	140	12	19	2	7
Retained Earnings	69	-2	0	2	-22
Income Statement Items (million dollars):					
Electric Operating Revenues	1	110	46	10	36
Net Electric Operating Income	*	28	23	7	-3
Net Interest Charges	0	11	65	3	14
Net Income	*	18	-33	5	-17
Ratios (percent):					
Common Equity Capitalization	100	51	-1	22	-15
Long-Term Debt Capitalization	0	49	101	78	115
Electric Plant/Total Assets	94	85	81	93	93
Interest Coverage	NA	333	*	284	NA
Return on Common Equity	1	15	NA	52	120
Return on Investment	1	7	-5	6	-10

[a]The full company names are Terra Comfort Corp., Ocean State Power Co., Catalyst Old River Hydroelectric Limited Partnership, Nevada Sun-Peak Limited Partnership, and Entergy Power, Inc.

*Less than 0.5 million dollars.

NA = Not available.

Notes: •This sample includes all nonutility power producers required to file FERC Form-1 for 1991. •Nevada Sun-Peak began operating in June 1991. •Percentages calculated on unrounded data. •Sum of components may not equal total due to independent rounding.

Source: Energy Information Administration, *Financial Statistics of Major Investor-Owned Electric Utilities 1991*, DOE/EIA-0437(91)/1 (Washington, DC, January 1993).

they are often partnerships of several different entities with a financial interest in the industry (e.g., utilities or their holding companies, fuel suppliers, utility plant developers, and operators).

One of the five nonutilities began operating during 1991. It is impossible to establish generalizations for nonutilities as a whole on the basis of this available data. Nonetheless, certain limited observations with regard to 1991 financial results can be made. For instance:

- The ratio of utility plant to total assets for non-utilities in Table 1 is higher than that for IOUs. In 1991 it ranged from 81 to 94 percent for non-utilities and in 1991 it was 72 percent for aggregate IOUs.[14] This may be explained by the fact that nonutilities concentrate on generation, at the exclusion of sales and customer relations.

- There are large variations both among nonutilities and between nonutilities and IOUs in net income and return on investment.

- The nonutilities included in Table 1 have various combinations of common equity investment and long-term debt or lease financing vehicles with complex and varying terms and conditions.

[14]Energy Information Administration, *Financial Statistics of Major Investor-Owned Electric Utilities: 1991,* DOE/EIA-0437(91)/1 (Washington, DC, January 1993), p. 22.

- Common equity capitalization for the nonutilities included in Table 1 varies widely. Regardless, two of the nonutilities listed in Table 1 have already been able to recover their initial equity investments due to the financing methods they adopted.

Ocean State Power, an independent power producer, is a 500-megawatt electricity generating facility in Burrillville, Rhode Island. This baseload, combined cycle, natural-gas-fired plant is the largest power plant to be built in New England in the last decade.

3. Legislative and Regulatory Basis for Change

The immediate causes of the recent rise in nonutility electric power generation in the United States were legislative and regulatory: the enactment of the Public Utility Regulatory Policies Act in 1978 and the more stringent regulatory review of utility costs by State regulators in the 1980's. These two events, which allowed the revival of nonutility electricity generation, were brought about by more fundamental economic and technological changes that preceded them. This chapter examines the immediate legislative and regula-tory events, while the following chapter considers the underlying economic and technological causes.

Legislation

Public Utility Holding Company Act

The Public Utility Holding Company Act (PUHCA), enacted in 1935, was aimed at breaking up the large and powerful trusts that then controlled the Nation's electric and gas distribution networks. The Act was passed at a time when financial pyramid schemes were extensive. These schemes allowed many operating utilities in many areas of the country to come under the control of a small number of holding companies, which were in turn owned by other holding companies. These pyramids were sometimes 10 layers thick. Before PUHCA, almost half of all electricity generated in the United States was controlled by three huge holding companies, and more than 100 other holding companies existed.[15] The size and complexity of these huge trusts made industry regulation by the States impossible. PUHCA gave the Securities and Exchange Commission (SEC) the authority to break up the trusts, to limit utilities in the future to the jurisdiction of single States, to confine activities to the business of operating a utility and its related affairs, and to regulate the reorganized industry in order to prevent their return.[16]

Immediately prior to PUHCA's passage the Federal Trade Commission (FTC), conducted an investigation that resulted in the recommendation to prohibit the holding companies from engaging in interstate electric sales, or from selling securities in interstate commerce.

The law contained a provision that all holding companies had to register with the SEC, which was authorized to supervise and regulate the holding com-pany system. One of the most important features of the Act was that the SEC was given the power to abolish the massive interstate holding companies by requiring them to divest their holdings until they became a single consolidated system serving a circumscribed geographic area. Another feature of the law restricted holding companies to engage in business that was essential and appropriate for the operation of a single integrated utility. This latter restriction practically eliminated the participation of nonutilities in electric power generation for resale.

Through the registration process, the SEC decided whether the holding company would need to be reorganized or exempted from the requirements of the Act. The SEC also was charged with regulating the issuance and acquisition of securities by holding companies. Strict limitations on intra-system transactions and political activities were also imposed.[17]

As of December 31, 1991, there were only 13 registered holding companies in the United States. Additionally, there were 47 holding companies exempt from SEC regulation by SEC order,[18] and 118 holding companies were exempt since they fell under the umbrella of PUHCA Section 3 (a) (1) and / or (2), which state:

The Commission, by rules and regulations upon its own motion, or by order upon application, shall exempt any holding company, and every subsidiary company thereof as such,

[15]The SEC actually noted 142 registered holding companies in 1939. Securities and Exchange Commission, *Fifth Annual Report of the Securities and Exchange Commission, Fiscal Year Ended June 30, 1939* (Washington, DC, 1940), pp. 1 and 43.

[16]Congressional Research Service, Report for the House Committee on Energy and Commerce, *Electricity: A New Regulatory Order?* (Washington, DC, June 1991), p. 167.

[17]For a more extensive discussion of PUHCA, see Energy Information Administration, *The Public Utility Holding Company Act of 1935: 1935-1992*, DOE / EIA-0563 (Washington, DC, January 1993), pp. 39-53.

[18]Verbal communication with the Securities and Exchange Commission, August 25, 1992.

Important Legislation

The Public Utility Holding Company Act of 1935 (PUHCA)
(Public Law 74-333)

PUHCA was enacted to break up the large and powerful trusts that controlled the Nation's electric and gas distribution networks. PUHCA gave the Securities and Exchange Commission the authority to break up the trusts and to regulate the reorganized industry in order to prevent their return. PUHCA was recently overhauled since many argued that PUHCA's regulations were impediments to the development of an efficient electricity market.

The Federal Power Act of 1935 (Title II of PUHCA)

This act was passed at the same time as the Public Utilities Holding Company Act. It was passed to provide for a Federal mechanism, as required by the Commerce Clause of the Constitution, for interstate electricity regulation. Prior to this time, electricity generation, transmission, and distribution was almost always a series of intrastate transactions.

The Public Utility Regulatory Policies Act of 1978 (PURPA)
(Public Law 95-617)

PURPA was passed in response to the unstable energy climate of the late 1970's. PURPA sought to promote conservation of electric energy. Additionally, PURPA created a new class of nonutility generators, small power producers, from which, along with qualified cogenerators, utilities are required to buy power.

The Energy Tax Act of 1978 (ETA)
(Public Law 95-618)

This act, like PURPA, was passed in response to the unstable energy climate of the 1970's. The ETA encouraged conversion of boilers to coal and investment in cogeneration equipment and solar and wind technologies by allowing a tax credit on top of the investment tax credit. It was later expanded to include other renewable technologies. However, the incentives were curtailed as a result of tax reform legislation in the mid-1980's.

The Clean Air Act Amendments of 1990
(Public Law 101-549)

These amendments established a new emissions-reduction program. The goal of the legislation was to reduce annual sulfur dioxide emissions by 10 million tons and annual nitrogen oxide emissions by 2 million tons from 1980 levels for all man-made sources. Generators of electricity will be responsible for large portions of the sulfur dioxide and nitrogen oxide reductions. The program instituted under the Clean Air Act Amendments of 1990 employs a unique, market-based approach to sulfur dioxide emission reductions, while relying on more traditional methods for nitrogen oxide reductions.

The Energy Policy Act of 1992 (EPACT)
(Public Law 102-486)

This law created a new category of electricity producer, the exempt wholesale generator, which circumvented PUHCA's impediments to the development of nonutility electricity generation. The law also allowed FERC to open up the national electricity transmission system to wholesale suppliers.

from any provision or provisions of this title, unless and except insofar as it finds the exemption detrimental to the public interest or the interest of investors or consumers if—

(1) such holding company, and every subsidiary company thereof which is a public-utility company from which such holding company derives, directly or indirectly, any material part of its income, are predominantly intrastate in character and carry on their business substantially in a single State in which such holding com-pany and every such subsidiary company thereof are organized;

(2) such holding company is predominantly a public-utility company whose operations as such do not extend beyond the State in which it is organized and States contiguous thereto.[19]

Federal Power Act

The Federal Power Act has been the centerpiece of Federal economic regulation of the electric utility industry for more than half a century since its passage in 1935. The Federal Power Act was passed as part of the same legislation that enacted PUHCA. As the electric power industry developed generation and transmission capability in the early part of this century, the industry was transformed from a local and urban industry into one capable of transmitting electric power long distances across State lines. As such, what had been under the jurisdiction of State regulators became subject to Federal regulation as stipulated by the Commerce Clause of the Constitution. In 1927 the Commerce Clause was invoked by the Supreme Court in the landmark decision, *Rhode Island Public Utilities Commission v. Attleboro Steam and Electric Co.*, where the Court held that a State could not regulate the price charged for electricity generated in that State and sold in another.

This prohibition against States regulating pricing and other interstate aspects of the industry came at a time when there was no Federal Government regulatory mechanism in place. The enactment of the Federal Power Act was the first attempt to bring interstate features of the electric power industry under governmental regulation.

The Act empowered the Federal Power Commission to regulate transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by public utilities. The Act also describes interstate commerce in this context to mean electricity transmitted from one State to another. Wholesale electric power under the Act meant the sale of electric energy for resale. The Act also describes those matters not brought under the jurisdiction of the Commission to include "facilities used for the generation of electric energy or . . . facilities used in local distribution or only for the transmission of electric energy in intrastate commerce or . . . facilities for the transmission of electric energy consumed wholly by the transmitter."[20]

National Energy Act of 1978

In October 1973 the Arab oil-producing nations imposed a ban on oil exports to the United States. Although the ban lasted only until March 1974, its effects increased public awareness of energy issues, resulted in higher energy prices, contributed to inflation, and acted as a catalyst for the proposal and adoption of the National Energy Act of 1978.

The National Energy Act, which was signed into law in November 1978, comprises five different statutes: the Public Utility Regulatory Policies Act (PURPA), the Energy Tax Act (Public Law 95-618), the National Energy Conservation Policy Act (Public Law 95-619), the Powerplant and Industrial Fuel Use Act (Public Law 95-620), and the Natural Gas Policy Act (Public Law 95-621). The general purpose of the National Energy Act was to ensure sustained economic growth while also permitting the economy time to make an orderly transition from the past era of inexpensive energy resources to a period of more costly energy.[21] Although it had numerous objectives, one goal of the National Energy Act was to develop renewable and alternative energy sources. Another was to reduce the Nation's dependence on foreign oil and its vulnerability to interruptions in energy supply.

[19]Public Utility Holding Company Act of 1935 (Public Law 74-333), Section 3.

[20]Congressional Research Service, Report for the House Committee on Energy and Commerce, *Electricity: A New Regulatory Order?* (Washington, DC, June 1991), pp. 131-133.
[21]John H. Minan and William H. Lawrence, "Federal Tax Incentives and Solar Energy Development," *Energy Law Service,* Monograph 7F (Wilmette, IL, September 1981), p. 5.

Public Utility Regulatory Policies Act

The most significant part of the National Energy Act with regard to the structure of the electric power industry was PURPA, specifically Section 2 of the Act:

> The Congress finds that the protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce require—
>
> (1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers,
>
> (2) a program to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rate applications before the Federal Energy Regulatory Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy,
>
> (3) a program to provide for the expeditious development of hydroelectric power, ...[22]

PURPA was designed to encourage the efficient use of fossil fuels in electric power production through cogenerators and the use of renewable resources through small power producers.[23] Both cogenerators and small power producers qualified under PURPA must have no more than 50 percent of their equity interest held by an electric utility. For a nonutility to be classified as a cogenerator under PURPA, it must produce electric energy and another form of useful thermal energy through the sequential use of energy. It must further meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). The operating requirements stipulate the proportion of output energy that must be thermal energy, and the efficiency requirements stipulate the maximum ratio of input energy to output energy.

For a nonutility to be classified as a small power producer under PURPA, renewable sources must provide at least 75 percent of the total energy input. Renewable energy includes solar, wind, biomass, waste, geothermal, and water (hydroelectric). Solar thermal technology converts solar energy through high concentration and heat absorption into electricity or process energy. Wind generators produce a mechanical energy directly through shaft power. Biomass energy is derived from hundreds of plant species, various agri-culture and industrial residues, and processing wastes. Industrial wood and wood waste is the most prevalent form of biomass energy used by nonutilities. Geothermal technologies convert heat naturally present in the earth into heat energy and electricity. Hydroelectric power is derived by converting the potential energy of water to electrical energy using a hydraulic turbine connected to a generator.

The key provision of PURPA required electric utilities to interconnect with and purchase power from any facility meeting the criteria for a qualifying facility (QF). It further required that the utility pay for that power at the utility's own incremental or avoided cost of production[24]. This provision created, by fiat, a market in which QFs could, unilaterally, sell electricity to utilities. To further ease the burden on nonutility companies wishing to enter the electric generating market, Congress exempted most QFs from rate and accounting regulation by FERC under the Federal Power Act, from regulation by the Securities and Exchange Commission under the PUHCA, and from State rate, financial, and organizational regulation of utilities. In passing PURPA, Congress ensured that QFs had a guaranteed market for their power at a price equal to the avoided cost of the utilities that purchased their power.

This is quite different from most regulation, which sets the price of electricity at the cost (to the producer) of producing it. The qualifying facilities themselves are not subject to cost-of-service regulation, and the prices paid to them are not based on their cost of producing the electricity. Instead, the prices they are paid reflect the avoided cost of the purchasing utility. That is, the cost the utility avoided by not producing the electricity

[22]Public Utility Regulatory Policies Act of 1978 (Public Law 95-617), Section 2.

[23]Because of amendments to PURPA in 1990, the term "small power producer" is now a misnomer; the amendments eliminated the original size criterion for all energy sources except hydroelectric, while maintaining the criterion for type of energy used.

[24]The law required electric utilities to purchase electricity from qualified facilities at “a rate which [does not] exceed the incremental cost to the electric utility of alternative electric energy . . . . [which the] utility would generate or purchase from another source.” Public Utility Regulatory Policies Act of 1978 (Public Law 95-617), Title II, Section 210, Paragraphs (b)(2) and (d).

From 1985 to 1991, nonutility generation by renewable sources has more than doubled. Renewable sources include technologies such as hydroelectric facilities (top left), photovoltaic (top right), wind (bottom left), and geothermal (bottom right).

received from the QF or purchasing it from another source. For these reasons, many new QFs have been built in recent years. In 1991, qualifying cogenerators accounted for 59 percent of all nonutility generating capacity, and qualifying small power producers accounted for 15 percent.

One initial interpretation of avoided cost under PURPA was the cost of additional electricity produced by the utility itself. In some States, the avoided cost pricing formulas forced utilities to pay for QF capacity that they did not need because the supply and demand balance for electricity was not considered in avoided cost. In the mid-1980's, several States began to review their own and others' experiences with PURPA imple-mentation. Maine, in particular, concluded that avoided costs could be established through competitive bidding among QFs as opposed to setting them administratively.

In 1984, Central Maine Power (CMP) and the Maine Public Service Commission (PSC) became the first to put competitive bidding into practice. CMP did this in an effort to protect itself from oversupply of electricity by QFs after the PSC decided that avoided-cost rates for QFs were to be based on the cost of a nuclear power plant. These high rates spurred a high volume of offers to supply more power than CMP needed. This switch to market-based pricing provided a new avoided cost for purchased power from QFs that was below the initial avoided cost levels that would have prevailed in the absence of bidding.[25]

Determining the effects of competitive bidding on the cost of power requires comparing estimates of what future costs and demand for electricity will be. An estimate must be made of the utility's total cost if it generates the power itself or purchases it through cost-based rates. This estimate must be compared with an estimate of the utility's total costs if it purchases the power competitively. Estimating future costs is difficult, since many factors, such as fuel prices, must be considered.

Some utilities have estimated the electricity cost savings from competitive bidding. Boston Edison estimates an 18-percent savings for the power purchased in one bid solicitation. Virginia Power estimates that the cost of the power purchased from the projects selected in the utility's first solicitation will be between 5 and 10 percent below the utility's estimated cost to provide the power itself. CMP estimates that the cost of electricity from projects selected in its third solicitation will be 5 to 12 percent lower than its avoided cost.[26] Allowing more electricity producers the opportunity to enter the wholesale market could increase options for utilities. Competition between suppliers could lead to lower prices, and thus lower the purchasing utility's costs of supplying electricity.

In passing PURPA, Congress established a set of incentives and opportunities to stimulate new institutional, technical, and economic diversity in the generation of electricity. It also opened the door for limited competition in generation markets. Between 1985 and 1991, the nonutility share of total U.S. electricity generation more than doubled; this would not have occurred had PURPA not exempted QFs from PUHCA and guaranteed them a market. But the passage of PURPA was only the last of several events that occurred since the oil embargo in 1973. The cost of generating power with large, centralized power plants rose dramatically in the years following 1973. Sharp fuel cost increases were followed by interest rates that more than tripled. Several other factors contributed to higher costs, including increased environmental and safety requirements, intentional construction time stretch-outs due to lack of demand, and, in some cases, poor management.[27]

Nonutility generation of electric power has been revived. Nonutility electricity generating facilities accounted for approximately one-fifth of all additions to generating capacity in the 1980's, and the Energy Information Administration projects that these facilities will contribute one-half of all net additions to generating capacity through the 1990's.[28]

[25]W. Harrison Wellford and Hope E. Robertson, "Bidding for Power: The Emergence of Competitive Bidding in Electric Generation," Working Paper No. 2, National Independent Energy Producers (March 1990), p. 3.

[26]U.S. General Accounting Office, Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives, *Electricity Supply: The Effects of Competitive Power Purchases Are Not Yet Certain,* GAO / RCED-90-182 (Washington, DC, August 1990), p. 5.

[27]This paragraph is drawn from on Office of Technology Assessment, U.S. Congress, *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition*, OTA-E-409 (Washington, DC, May 1989), pp. 3-4. These arguments are extended in the next chapter.

[28]Energy Information Administration, *Annual Energy Outlook 1993*, DOE / EIA-0383(93) (Washington, DC, January 1993), Table A5.

Energy Tax Act

Tax subsidies and tax incentives have been commonly used in the United States to promote increases in domestic energy production and / or to foster commercialization of new technologies.[29] However, with the exception of hydroelectric power technology, other renewable energy technologies engaged in electric power generation received virtually no favorable tax treatment under Federal law prior to 1978.[30]

One of the component statutes of the National Energy Act of 1978—the Energy Tax Act (ETA)—provided a 10-percent business tax credit for investment in six selected categories of energy property (with solar and wind energy properties being the major beneficiaries). This energy tax credit was in addition to the already existing 10-percent investment tax credit. Thus, a total of 20 percent was offered to encourage investment in qualified energy property.

The energy tax credit was originally due to expire in 1982; however, in 1980, Congress determined that the tax credit should apply to a broader range of alternative energy sources, including biomass, geothermal, ocean thermal, and other renewable sources. In addition, the rate of investment tax credits on certain technologies was increased from 10 to 15 percent. However, this incentive was discontinued with the tax reform of the mid-1980's.

The recent National Energy Strategy, developed by the Department of Energy, recommended continuing investment tax credits to attain the objectives of reducing the costs of, and increasing industry confidence in selecting solar, wind, biomass, and geothermal tech-nologies to generate electric power.[31] The provisions of the Energy Policy Act of 1992 (EPACT) include a permanent 10-percent investment tax credit for solar and geothermal projects, and a 10-year production credit for wind and biomass plants that are brought on line between 1994 and 1999.

The Energy Tax Act probably was not a major force in spurring the growth of the nonutility industry. The Act encouraged the use of renewable resources, the conversion of boilers to coal, and the installation of cogeneration equipment by allowing a tax credit on top of the investment tax credit. The effect of this Act on the changing structure was minimal when compared with PURPA. It mainly contributed to the growth of small power producers, who must use solar, wind, biomass, waste, geothermal, or water to be a QF. The tax credits lowered the cost of producing electricity from renewable sources, making them more economically competitive with other technologies, especially in California, where oil- and gas-fired plants set the QF's avoided cost.

For example, some of the expansion of geothermal power facilities is attributable to tax credits / subsidies. With 2,719 megawatts of installed capacity at 70 sites at the end of 1990, facilities that generate electricity from geothermal sources claimed a large portion of the total amount of business credits.[32] Over 90 percent of this capacity is located in California, the remainder in Utah and Nevada. An estimated 15.5 billion kilowatthours of electricity were produced from geothermal sources in 1989. In contrast, wind and solar thermal generating capacities, also mostly located in California, total less, 1,652 megawatts and 360 megawatts, respectively, at the end of 1991.[33]

Industry advocates maintain that the future penetration of renewable technologies would be further accelerated by the continuation of tax credits and incentives. To be more effective and to aid long-term investment plan-ning, tax benefits must also be made available on a long-term (if not on a permanent) basis. The uncertainties associated with continued availability of these credits may have contributed to the recent demise of Luz International Corporation in the solar field.[34]

[29]Estimates of Federal contribution to the development of civilian commercial nuclear power industry in the United States are stated to be in the range of $11.3 billion to $12.3 billion in 1979 dollars. (For further details, see Energy Information Administration, *Federal Support for Nuclear Power: Reactor Design and the Fuel Cycle*, DOE / EIA-0201 / 13 (Washington, DC, February 1981), p. 62.) For the period from 1918 through 1978, another study estimates that direct Federal subsidies (in 1977 dollars) to the nuclear, coal, oil, natural gas and electrical industries aggregated $217.4 billion. (See B.W. Cone et al., Pacific Northwest Laboratory, *An Analysis of Federal Incentives to Stimulate Energy Production* (Richland, WA, 1980), p. 6.)

[30]Hydroelectric power projects developed in the public sector include varying amounts of direct or indirect subsidies.

[31]U.S. Department of Energy, *National Energy Strategy* (Washington, DC, February 1991), p. 119.

[32]Energy Information Administration, *Geothermal Energy in the Western United States and Hawaii: Resources and Projected Electricity Generation Supplies*, DOE / EIA-0544 (Washington, DC, September 1991), pp. 8-9.

[33]Nonutility capacity data are from the Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report." Utility capacity data are from the Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

[34]Newton D. Becker, "The Demise of Luz: A Case Study," *Solar Today* (January / February 1992), pp.24-26.

Clean Air Act Amendments of 1990

The Clean Air Act Amendments of 1990 (CAAA90) may have substantial effects on nonutilities in the future. Among other things, the CAAA90 were enacted to reduce sulfur dioxide (SO_2) emissions from electric generating units.[35] The CAAA90 also was the first piece of legislation that defined an independent power producer. It specified them as a facility that:

> is used for the generation of electric energy, 80 percent or more of which is sold at wholesale; is non-recourse project-financed as such term is defined by the Secretary of Energy within three months of the date of enactment . . .; does not generate electric energy sold to any affiliate. . . of the facility's owner or operator unless the owner or operator of the facility demonstrates that it cannot obtain allowances from the affiliate; and is a new unit required to hold allowances under this title.[36]

The bill guarantees future nonutility units access to a limited pool of emission allowances and exempts existing nonutility projects from the requirements of the legislation. This exemption results in electricity production cost differences between the two types of ownership.

All utility units must obtain allowances for emissions beginning in 2000.[37] Most utilities with units that have been or will be in existence between 1985 and 1995 will have a potential emissions baseline from which the number of allowances that they will be allocated is computed. Under the legislative provisions for distribution of the allowances, utilities are eligible to receive a certain number of allowances at no cost for plants that existed at the time the Act took effect. All utility units (both existing and future) will be required to possess allowances to cover future emissions. However, existing nonutility units, including units under development at the time of passage of the bill, are exempt from being required to obtain SO_2 emission allowances. Future nonutility units will be required to possess allowances for their emissions but will not be given any allowances free of charge.

For existing units, the relative advantage of utilities versus nonutilities depends largely on whether the utility unit emits more or less than 1.2 pounds of SO_2 per million Btu of coal input. Existing nonutility units, regardless of their emissions rate, will not need to acquire any allowances for their emissions and will receive no allocation of allowances. However, utility units will need to acquire allowances for their emissions. An existing utility unit emitting more than 1.2 pounds will only receive allowances equal to approximately 40 percent of its 1985 emissions. The remaining 60 percent must be obtained from another source or be eliminated.[38] In the case of an existing utility unit emitting less than 1.2 pounds of SO_2 per million Btu, the utility will receive allowances equivalent to approximately 135 percent of its 1985 emissions. If its emissions have not increased, it will be left with an excess of allowances that it can sell on the private market.[39]

Another difference between the treatment of utilities and nonutilities in CAAA90 is their access to obtaining

Some coal-fired power plants have been retrofitting advanced flue gas desulfurization equipment (FGD) in emission stacks to reduce sulfur dioxide emissions. With the passage of the Clean Air Act Amendment of 1990, more facilities are planning to retrofit FGD equipment.

[35]Nonutilities are affected by other portions of CAAA90, including a permitting program, an ozone nonattainment requirement, and toxic emission controls.

[36]Clean Air Act Amendments of 1990 (Public Law 101-549), Section 416.

[37]The top emitting units must obtain permits beginning in 1995.

[38]The utility could choose to pay $2,000 for each ton of SO_2 it emits in excess of its allowances, but these emissions must also be offset the following year.

[39]Energy Information Administration, *Annual Outlook for U.S. Electric Power 1991*, DOE/EIA-0474(91) (Washington, DC, July 1991), p. 32.

SO_2 emission allowances for new generating units. New generating units of both utilities and nonutilities that meet the requirements in the CAAA90, are required to obtain allowances for emissions. However, nonutilities will have preferential access to a limited special reserve of allowances to be established in 1993. This reserve was set aside for the purpose of providing a contingency source of allowances to nonutilities. Utilities may purchase allowances from this reserve only after nonutilities have purchased their desired amount. However, the Act specified that an allowance to emit one ton of SO_2 from this reserve is to be priced at $1,500,[40] and the reserve is limited to a very small percentage of the allowances issued every year. The purchase procedures and methods for ensuring preference for nonutilities have not been determined by the U.S. Environmental Protection Agency.

Of course, both utilities and nonutilities will be able to purchase allowances in the private market (and in a very small Government-sponsored auction market). Because the private market is potentially the dominant source of allowances, if it functions well, both utilities and nonutilities will be able to obtain allowances there on an equivalent basis. For new units, this leaves utilities and nonutilities on an equal footing. If the private market fails, then nonutilities have some advantage in obtaining additional allowances through their preferential treatment in the direct sale of the limited special reserve.

Energy Policy Act of 1992

Despite the success of PURPA, some contend that it did not go far enough. In 1992, President George Bush signed EPACT, which substantially reforms PUHCA and makes it even easier for nonutility generators to enter the wholesale market for electricity by exempting them from PUHCA constraints. The law includes language that creates a new category of power producers, called exempt wholesale generators (EWGs). By exempting EWGs from PUHCA regulation, the law has eliminated a major barrier for utility-affiliated and nonaffiliated power producers who want to compete to build new non-rate-based power plants. These EWGs will differ from PURPA QFs in two ways. First, they will not be required to meet PURPA's cogeneration or renewable fuels limitations. Second, utilities will not be required to purchase power from EWGs. In order to facilitate the marketing of EWG power, transmission provisions were included in the law that give FERC the authority to order utilities to provide point-to-point access on their transmission systems to further encourage competition in the bulk power market.

The law is being hailed as the most significant piece of energy legislation since the 1970's. In addition to giving EWGs and qualifying facilities access to distant wholesale markets, the new law also provides transmission-dependent utilities the ability to shop for wholesale power supplies and frees these utilities, mostly municipal utilities and rural cooperatives, from their dependency on surrounding investor-owned utilities for wholesale power requirements.

The transmission provisions could lead over several years to what will in effect be, for wholesale transactions, a nationwide open-access electric power transmission grid. Andrew Zausner, chairman of the PUHCA Reform Coordinating Council, has suggested that by January 1, 1997, there will not be a major utility left in the Nation without a transmission tariff of general applicability (a rate schedule applicable to others for using the utility's transmission facilities).[41] IPPs, publicly owned utilities, rural cooperatives, industrial producers, and consumer advocates gained the ability to win from FERC orders that will require transmission-owning utilities to provide transmission service at FERC defined “just and reasonable” rates.

The language of the law concerning pricing directs FERC, when it issues a transmission order, to approve rates which permit the utility to recover “all legitimate, verifiable economic costs incurred in connection with the transmission services.” Such costs include “an appropriate share, if any, [of] necessary associated services, including, but not limited to an appropriate share of any enlargement of transmission facilities.” The language also says that FERC “shall ensure, to the extent practicable,” that costs incurred by the wheeling utility are recovered from the transmission customer rather than “from a transmitting utility's existing wholesale, retail, and transmission customers.”

Probably the most salient characteristic of the reforms to PUHCA was the removal of SEC powers of

[40]Initial transactions between utilities in the private market have priced permits at between $250 and $500. “$SO_2$ Allowance Market Inaugurated with Two Sales; More Expected Soon,” *Independent Power Report* (May 22, 1992), p. 15.

[41]“House-Senate Conferees Wrap up Bill; Agree to Amend PUHCA, Mandate Access,” *Electric Utility Week*, October 5, 1992, p. 16. The summary of EPACT in this report is based on this article.

regulation and the expansion of FERC authority.[42] However, the most bitter dispute over PUHCA reform was in the area of transmission access. One line of demarcation dividing winners from losers is the attitudes of the two groups toward the issue of transmission access. Some nonutility groups had argued that revising PUHCA without revising transmission-access rules would reinforce the utility monopolistic structure. The main thrust of the argument against PUHCA reform with increased transmission access authority was that the high level of reliability enjoyed by the Nation would be compromised.

Although regulated public utilities had no general obligation to provide access to their transmission lines before EPACT, there are several, although restricted, exceptions to this generalization. One is the requirement, under PURPA, that utilities interconnect with and purchase power from qualifying facilities. Another is that under the Federal Power Act, as amended by PURPA, FERC has the authority to require wheeling under limited circumstances. But, in its first deliberation on this authority, FERC found that this authority was limited so that it did not allow FERC to require a utility to wheel power to its wholesale customers or to encourage competition in bulk power markets.[43] This interpretation of PURPA circumscribed the circumstances under which FERC could order wheeling. The interpretation by FERC was later upheld by the courts. Of course, the recent enactment of EPACT broadens FERC's authority to order wheeling.

In 1989, President George Bush and Secretary of Energy James Watkins announced plans to establish a national energy strategy. As a result, President Bush signed into law the Energy Policy Act on October 24, 1992.

[42]For of further discussion of this point, see U.S. General Accounting Office, Report to the Chairman, Subcommittee on Energy and Power, Committee on Energy and Commerce, House of Representatives, *Potential Effects of Amending the Public Utility Holding Company Act*, GAO/RCED-92-52 (Washington, DC, January 1992), p. 29.

[43]*Southeastern Power Administration v. Kentucky Utilities Company*, 25 FERC ¶ 61,204 (1983).

The Federal courts can also require wheeling, but only when the Sherman Antitrust Act has been violated.[44] These violations include circumstances where a refusal to wheel power is determined to be anti-competitive or an attempt to monopolize a particular market. Also, under the Atomic Energy Act, the Nuclear Regulatory Commission and the U.S. Attorney General may require wheeling access as a condition for issuing a construction permit for a nuclear power plant.[45]

EPACT broadens these exceptions substantially by giving FERC new authority to order utilities to provide wheeling over their transmission systems to utilities and nonutilities. On the other hand, the Act prohibits FERC from ordering "retail wheeling" (transmitting power to a final consumer).

Regulation

State Public Utility Commissions

State regulation of utilities began early in this century. Traditionally the regulation of most activities of privately owned electric utilities has been conducted by the individual States (Federal, State, municipal, cooperative, and other utilities are often not regulated directly). The primary responsibility of State Public Utility Commissions (PUCs), which exist in all States with privately owned utilities, is to regulate the prices for electricity that privately owned utilities may charge to retail customers. Generally, PUCs regulate retail electricity prices by allowing utilities to charge only enough to recoup their total expenses of providing electricity, although the specifics vary by individual State. Total expenses include fuel, operations and maintenance, and capital, including a "fair rate of return" on the capital of the utility. A fair rate of return is defined as being equal to a return on investments having similar risk and being high enough to raise financial capital for the utility.[46]

Electric utilities and State commissions historically have often seemed to implicitly agree to an arrangement, in which utilities have an obligation to serve virtually all of the electricity demand in their service territory at the regulated price. In return, commissions allow utilities to charge prices that will earn them a fair rate of return on their investment. Regulation by State PUCs has become a complex and difficult process, especially since the 1970's. Before that, the per-unit nominal costs of producing electric power were generally falling,[47] leaving commissions in the enviable position of being able to lower prices to consumers, while still allowing utilities to cover their production expenses and earn a fair rate of return on their investment. Between 1973 and 1982, the real, per-unit costs of producing electric power increased by more than half (See following chapter).

Many State PUCs examined utility expenses intensively as utilities requested increases in retail prices based on these cost increases. One particular area of concern since the 1970's has been the "prudence" of utility investments in new power production facilities. The investments were undertaken with the expectation that the demand for electricity would continue to grow rapidly; it did not. This resulted in excess production capacity available or under construction at many utilities. Since new excess capacity often does not meet the "used and useful" criteria employed by many commissions, the investment in the new capacity may be deemed not prudent and may not be included in the utility's ratebase for retail price determination. Under these circumstances, the utility is not allowed to earn a full rate of return on its investment.

The exclusion of excess capacity from the ratebase by PUCs may be a method to simulate a competitive market for electric utilities.[48] In a competitive market, if a firm builds excess capacity, it earns less than a normal rate of return on the excess capacity. This lower return occurs regardless of the reason for the excess capacity—even if it was undertaken in good faith. Excluding excess capacity from the ratebase similarly lowers the return on capacity. Some members of the electric utility industry, among others, have argued that the financial scrutiny by regulators was unfair because it did not take into account that the utilities invested in the excess capacity in good faith.[49]

Regardless of their cause or fairness, the disallowance of some utility investment in plant and equipment by State commissions has increased the riskiness of utility

[44] *Otter Tail Power Company v. Federal Power Commission*, 410 U.S. 366 (1973).

[45] *Alabama Power Company v. Nuclear Regulatory Commission*, 692 F.2d 1362 (11th Cir. 1982).

[46] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944).

[47] These costs are determined by the State commissions in setting average retail rates. Edison Electric Institute, *Historical Statistics of the Electric Utility Industry through 1970* (Washington, DC, April 1974), p. 165.

[48] For example, see Roger Sherman, *The Regulation of Monopoly* (Cambridge: Cambridge University Press, 1989), pp. 196-197.

[49] For example, see W.S. White, Jr., and Gregory S. Vassell, "U.S. Electric Power Supply at the Crossroads—The Technical and Historical Background," *Public Utility Fortnightly* (January 5, 1989), p. 9.

investments and has discouraged utilities from constructing new generating facilities. This has occurred because the uncertainty of recovering capital costs has increased for utilities, with no commensurate increase in their overall allowed return. Moreover, to the extent these disallowances are not extended to electricity purchased from another source, utilities are more inclined to purchase power instead of producing it. In addition, traditionally, electric utilities have not been wholesale suppliers to each other. This reluctance by utilities to build new capacity provides nonutilities with an opportunity to enter the generation market and sell electricity to utilities for distribution to consumers.

Except for purchases from QFs, utilities generally buy electric power at wholesale, to be resold to consumers or other utilities, under FERC regulation when the seller is under FERC jurisdiction. In general, State PUCs cannot question the expense of wholesale power for a utility when the wholesale rates have been approved by FERC.[50] Thus, before PURPA, the price of wholesale power from either utilities or nonutilities had been based on the FERC-determined expenses of the producer of the electricity.

PURPA added another basis for determining wholesale prices. Under PURPA, wholesale electric power rates from QFs are set by State PUCs at the avoided cost of producing electricity for the buying utility. In addition, the commissions have wide latitude in defining what is and is not included in avoided cost, and the utility must buy as much power as the QF wishes to sell. Thus, the price for wholesale electricity from QFs, still the vast majority of nonutilities, bears no relationship to the production costs of the selling company. If commissions set avoided cost higher than the long-run average cost of QFs, then QFs will increasingly enter power production.[51]

Federal Regulation

Federal regulation of electric power[52] is based on the Commerce Clause of the U.S. Constitution, which holds that only the Federal Government may regulate interstate commerce.[53] Thus, not only is the Federal Government authorized to regulate interstate commerce, but State governments are prohibited from doing so. In this way Federal regulation complements State regulation by focusing on the interstate activities of electricity producers, leaving the regulation of intrastate activities to the States.

Three laws, the Federal Power Act, PURPA, and the recently enacted EPACT, form the basis for Federal involvement in the regulation of wholesale electric power transactions. FERC is the primary agency responsible for enforcing Federal regulation of electric power transactions; it replaced the Federal Power Commission in 1977.[54] FERC is composed of five commissioners, appointed by the President with the advice and consent of the Senate.

The Federal Power Act granted the Federal Government explicit authority over certain utility rates for interstate wholesale trade in 1935.[55] The authority was interpreted by the Supreme Court to include virtually all wholesale sales of electricity in the 1960's.[56] FERC sets the rates for virtually all wholesale electricity trade, except for a large part of the State of Texas, which is not routinely interconnected with the remainder of the U.S. transmission system.

The Federal Power Act requires that FERC set rates to be "just and reasonable." Traditionally, under this criterion, rates have been based on the cost to the seller of producing or acquiring the electricity. To implement this ideal, wholesale rates are set to just recover the

[50]See *Narragansett Electric Company v. Burke*, 119 R.I. 559, 381 A.2d 1358 (1977). However, an exception permitted State commissions to disallow the cost of wholesale power purchased at a FERC approved rate if the State commission determined that the utility was not prudent when it agreed to the purchase. See *Pike County Light and Power Company v. Pennsylvania Public Utility Commission*, 77 Pa. Commw. 268, 465 A .2d 735 (1983). Nonetheless, codification of this "Pike County doctrine" was not included as part of EPACT.

[51]If avoided costs exceed the short-run marginal costs of producing power to the utility, and some utility generation is displaced by nonutility generation, then the cost to the utility of supplying power will increase.

[52]For an extensive discussion of Federal regulation of electric power, on which the following discussion is based, see Congressional Research Service, Report for the House Committee on Energy and Commerce, *Electricity: A New Regulatory Order?* (Washington, DC, June 1991).

[53]The Supreme Court explicitly confirmed the clause for electric utilities when it held that a State could not regulate the price charged for electricity generated in that State and sold in another. *Rhode Island Public Utilities Commission v. Attleboro Steam and Electric Company*, 273 U.S. 83 (1927).

[54]The Federal Power Commission was initially established in 1920, with major modifications in 1930, 1935, and 1938.

[55]In general, FERC regulates interstate wholesale sales by investor-owned utilities, independent power producers, and some cooperatively owned utilities. It also reviews the wholesale rates of the Federal power marketing agencies.

[56]Referred to as the *City of Colton* decisions, the lead case was *Federal Power Commission v. Southern California Edison Company*, 376 U.S. 205 (1964). The rationale was that because individual electrons could not be identified and their flow could not be (economically) controlled, if a utility has interstate connections, then some of its electricity may have come through interstate commerce. Interestingly, even though a utility forwards electricity of indeterminate source to end users, this rationale has not been extended to retail sales.

expected total expenses incurred in producing or acquiring the electricity.[57] This process is in principle similar to that used by State PUCs to set retail elec-tricity rates.

FERC does not differentiate between utilities and nonutilities in the ratemaking process. Thus, if there are any wholesale rate differences between utilities and nonutilities, they should come about only because of differences in the costs of producing electric power.

In 1987, with some earlier exceptions, FERC began approving some wholesale rates that will more than recover the total expense of producing the electricity, calling them market-based rates because they are based on market conditions and not on the cost of producing or acquiring the electricity. Between 1987 and September 1992, of the 45 rate cases concerning market-based sales for resale, 33 have been approved, 9 have been rejected, and 3 are pending.[58]

Just as for cost-based rates, FERC does not differentiate between utility and nonutility sellers in determining market-based rates. Both have to meet requirements that they do not possess market power relevant to the transaction, including "dominance in the relevant product market, typically for generation services; control of entry barriers, particularly transmission, and abuse of affiliate relationships."[59] In addition, this small number of cases should not yet have any noticeable effect on utility and nonutility wholesale electricity prices because of its recent and limited use.

FERC will developseveral rules to implement the electric power sections of EPACT.[60] The Act directs FERC to set guidelines and requirements for exempt wholesale generators (EWGs), a new class of nonutilities to be exempt from PUHCA regulation. Other potential topics for the rules include regional transmission groups, market-based pricing, affiliate transactions, and transmission access and pricing.

[57]More precisely, total expenses are the basis for a price ceiling under cost-based rates. Some utilities have been allowed to charge a price below their total expenses, as long as it exceeded their operating (out of pocket) expenses.

[58]Verbal communication with William Booth, January 8, 1993. For a more extensive discussion of market-based rates, see Bernard W. Tenenbaum and J. Stephen Henderson, "Market-Based Pricing of Wholesale Electric Services," *The Electricity Journal*, vol. 4, No. 10 (December 1991), pp. 30-45.

[59]Bernard W. Tenenbaum and J. Stephen Henderson, "Market-Based Pricing of Wholesale Electric Services," *The Electricity Journal*, vol. 4, no. 10 (December 1991), p. 31.

[60]FERC was expected to request comments on new transmission rules at the end of 1991, but delayed because of the debate on EPACT.

4. Economic and Technological Precursors to Change

Before the passage of the Public Utility Regulatory Policies Act (PURPA) and the more stringent regulatory review of utility costs by State regulators, economic and technological developments in the U.S. electric power industry were creating a climate that encouraged changes in the structure of the industry. Indeed, PURPA and the more stringent review of costs by State regulators may best be seen as the legislative and regulatory responses to those underlying economic and technological factors.

Economic Factors

The real cost of generating electric power increased dramatically in the 1970's and early 1980's. Because the price of electricity is set by a State Public Utility Commissions (PUC), in general, at the utility's average cost of production, including an allowed rate of return on investment, the real increase in cost can be approximated by the increase in the real retail price of electricity (Figure 15). From 1973 through 1982, electricity prices in 1991 dollars increased from 5.6 cents per kilowatthour to 8.5 cents per kilowatthour.[61] Over this period, electricity prices were rising much faster than overall inflation; the nominal price of electricity approximately tripled while the implicit price deflator for the gross domestic product only doubled. This rise in the price of electricity is even more remarkable when viewed in its historical context. From 1960 through 1970, the price of electricity decreased by 30 percent in real terms. The later increase in the cost of producing electricity followed from changes in all three components of its generating cost: fuel, capital costs, and operation and maintenance costs.

The fuel price increases stemmed mostly from the oil price shocks of 1973 and 1979-81. Delivered coal prices rose partially in anticipation of the increased demand for coal that would occur if utilities and industry switched from oil to coal and partially because of higher transportation costs. The real cost to utilities of coal, which fuels more electricity generation than all other fuels combined, increased from $26 per short ton to $49 per short ton (1991 dollars) between 1973 and 1982.[62] Over the same period, the real cost of natural gas to electric utilities increased from $1.08 per thousand cubic feet to $9.86 per thousand cubic feet (1991 dollars), because natural gas is a substitute for oil and because of the partial deregulation of natural gas prices with the Natural Gas Policy Act of 1978. These increases resulted in a sharp rise in the cost of producing electricity, because outlays for fuel dominate operating expenses for electricity production.[63]

Average operation and maintenance costs for electricity generating plants increased in real terms, mostly for nuclear powerplants in the 1970's and 1980's. Between 1974 and 1982, nuclear plant operation and maintenance costs increased from $17 per kilowatt to almost $45 per kilowatt (1982 dollars). In addition, the post-operational capital expenditures increased from $8.50 per kilowatt to $28 per kilowatt (1982 dollars). The operation and maintenance costs have continued to increase until 1990, but the post-operational capital expenditures declined after reaching a peak in 1984.[64]

Also in the 1970's and 1980's, several factors caused capital costs to increase. The interest rate on high-grade corporate bonds went from 4.4 percent in 1961 to 7.4 percent in 1971 and to 14.2 percent in 1981.[65] Since electric power production requires large amounts of capital, the cost of debt to finance capacity expansion is important to the electric power industry. Increasing interest rates raised the cost of constructing new facilities, including power plants, transmission lines,

[61]Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC, June 1992), pp. 229 and 321.
[62]Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 1992) p. 90.
[63]Fuel expenses were 67, 84, and 77 percent of power production expenses (excluding capital expenditures) for major investor-owned electric utilities in 1990, 1980, and 1970, respectively. Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities 1990*, DOE/EIA-0437(90)/1 (Washington, DC, January 1992), p. 26, and predecessor issues.
[64]Energy Information Administration, *An Analysis of Nuclear Plant Operating Costs: A 1991 Update*, DIE/EIA-0547 (Washington, DC, May 1991), p. 4.
[65]*Economic Report of the President* (Washington, DC, February 1992), p. 378.

Figure 15. Real Retail Prices of Electricity Sold by Utilities, 1970-1991

Notes: •Prices are in 1991 dollars, calculated using the implicit GNP price deflator. •Data for 1979 and earlier are for Classes A and B privately owned electric utilities only; data for 1980 and forward are for selected Class A utilities whose electric operating revenues were $100 million or more during the previous year. •Data shown in Table C6.

Source: Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC, June 1992), p. 229.

and distribution systems. Interest during construction can represent as much as 15 to 20 percent of the real capital investment cost of a new, large, baseload powerplant.[66]

In addition, two sets of Federal regulations added to the cost of generating electric power. In the 1970's and 1980's, the U.S. Environmental Protection Agency established and strengthened air quality standards that required new coal-fired utility boilers to limit their emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter. In order to do so, utilities often added equipment to new coal-fired plants (but usually not existing plants), which increased their construction and operating costs. Federal laws also control water quality and solid waste, but the Federal air-quality regulations had the major impact on the cost of new electricity generating facilities.

The Federal air-quality regulations are outlined in the New Source Performance Standards (NSPS), the Revised New Source Performance Standards (RNSPS), and the Prevention of Significant Deterioration rules. These standards limit the emissions of SO_2, NO_x, and particulate matter from new power plants. Pre-NSPS units (those on which construction began before August 18, 1971) are subject only to State Implementation Plans, which are generally less stringent than NSPS. NSPS units (those on which construction began after August 17, 1971, but before September 19, 1978) must not emit more than 1.2 pounds of SO_2 per million Btu of heat input. RNSPS units (those on which construction began

[66]Organization for Economic Cooperation and Development, *Projected Costs of Generating Electricity from Power Stations for Commissioning in the Period 1995-2000* (Paris, France, 1989), pp. 70-71.

Finally, the U.S. Nuclear Regulatory Commission (NRC) added additional safety regulations for nuclear power plants. In particular, the 1979 accident at the Three Mile Island nuclear plant ignited a strong regulatory reaction that redefined acceptable safety standards. The NRC enacted two plans for regulatory compliance, a short-term plan and a long-term plan. The short-term recommendations were geared toward quickly correcting the specific deficiencies that could pose an immediate danger. The result was that a number of nuclear units under construction were delayed for several years as the units were modified to meet the new safety standards. In addition, delays occurred during the process of obtaining an operating license. These delays and modifications increased the real construction costs of the plants, including the interest expense.

The estimated average costs per kilowatt of net summer generating capability are available for the nuclear units and the fossil-fuel steam plants that entered commercial operation in the United States from 1968 through 1988. The data show that the average construction cost per kilowatt of net summer capability increased from $161 (nominal dollars)[68] in the period from 1968 through 1971 for 11 nuclear units to $4,057 in 1987, for 7 nuclear units.[69] The average construction costs for fossil-fuel steam-electric plants increased from $137 per kilowatt (nominal dollars) in 1968 through 1971 to $961 per kilowatt in 1987.[70] In comparison to these nominal increases for nuclear and fossil-fuel steam unit con-struction costs, the implicit price deflator for the gross national product only tripled over the same period.

One component of the cost of producing electricity is the cost of fuel. From 1970 to 1990, the nominal prices of natural gas and petroleum to utilities increased approximately 700 percent. Coal prices, however, increased less than 400 percent, from 0.31 dollars per million Btu in 1970 to 1.45 dollars per million Btu in 1990.

after September 18, 1978) must also meet this limit. In addition, RNSPS units that emit between 0.6 and 1.2 pounds per million Btu must reduce their SO_2 emissions by 90 percent. RNSPS units that emit less than 0.6 pounds per million Btu must reduce their SO_2 emis-sions by 70 percent.

In effect, the revised standards require the use of flue gas desulfurization equipment or “scrubbers” to reduce SO_2. Typical scrubbers including the flue gas desulfurization structures and equipment with a spare module added approximately 25 percent to the cost of a new coal-fired powerplant in the 1970's and the 1980's.[67] More recently, the Clean Air Act Amendments of 1990 will require most generating units to obtain allowances for each ton of SO_2 emitted.

State PUCs responded to these cost increases with more critical cost reviews, performance incentive programs, disallowances of some costs, prudence reviews, and new cost recovery procedures such as rate-base phase-in. These procedures increased the financial risk for utilities to build new, large-scale powerplants and were a fundamental change from previously established ratemaking procedures.

[67]U.S. Department of Energy, *Phase IX Update (1987) Report For The Energy Economic Data Base Program EEDB - IX*, DOE / NE-0091 (Washington, DC, July 1988), p. 5-13.

[68]Since these construction costs are in nominal dollars, the four-year averages are in mixed-current dollars, which are the combination of nominal amounts from different years without adjusting them for inflation.

[69]Energy Information Administration, *Nuclear Power Plant Construction Activity 1988*, DOE / EIA-0473(88) (Washington, DC, June 14, 1989), p. 11.

[70]Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1989*, DOE / EIA-0455(89) (Washington, DC, March 1991), p. 38. Energy Information Administration *Thermal-Electric Plant Construction Cost and Annual Production Expenses-1981*, DOE / EIA-0323(81) (Washington, DC, January 1984), p. 9.

Along with reductions in sulfur dioxide, coal-fired facilities are also seeking to lower nitrogen oxide emissions. Some facilities are retrofitting low nitrogen oxide cell burners into boilers to lower emissions.

Technological Factors

Thermal Efficiency

For many years the electric power industry was one of the leading sectors of the economy in terms of technical innovation and productivity growth. Through technical innovations in the design of steam turbines, the industry's thermal efficiency was substantially increased. The amount of heat input, measured in British thermal units (Btu), needed to generate a kilowatthour of electricity with steam turbines decreased by almost 40 percent between 1925 and 1945, and by another 35 percent between 1945 and 1965. Since 1965, however, thermal efficiency has improved negligibly.[71] Increasing thermal efficiency enabled utilities to reduce electric power generation costs. The absence of such improvements since 1965 has prevented utilities from offsetting other rising costs and, as discussed in the previous chapters, has provided the opportunity for nonutilities to expand.

The first fossil-fueled steam turbines, with a capacity of about 5 megawatts, were placed into operation in the United States just after the turn of the century. The basic thermodynamic properties of the conventional boiler steam turbine cycle are that fuel is burned in a furnace to generate pressurized high-temperature steam. The pressurized steam is then expanded through a turbine which turns a generator to produce electricity. The steam exhausted from the turbine is then cooled in a condenser and returned to the boiler to begin the cycle again. The thermal efficiency of the steam cycle increases with the temperature and pressure of the steam, the thermal efficiency of the boiler, the efficiency of the turbine, and the size of the turbine and boilers.

The desire to increase thermal efficiency in turn led to a demand for larger units operating at higher steam temperatures and pressures. The technical design frontier was limited by the ability of boilers to withstand high temperatures and pressures. By the late 1950's, a steam temperature threshold in the range of 1,000 to 1,010 degrees Fahrenheit was reached, and almost all units built since then have been designed to operate at temperatures in this range. Subcritical boilers have a pressure range up to 2400 pounds per square inch. The frontier was pushed further by incremental advances in metallurgy involving the development of high temperature steel alloys. Since about 1960, the primary technological frontiers have been in the steam pressure and unit size dimensions.[72] Innovation in conventional steam generating technology has been driven by a continuing effort to improve thermal efficiency and to reduce the construction costs of generating units.

[71]Paul L. Joskow, "Productivity Growth and Technical Change in the Generation of Electricity," *The Energy Journal*, vol. 8, no. 1 (1987), p. 18. Also see Energy Information Administration, *Electric Plant Cost and Power Production Expenses 1990*, DOE/EIA-0455(90) (Washington, DC, June 1992), p. 37.
[72]Paul L. Joskow, "Productivity Growth and Technical Change in the Generation of Electricity," *The Energy Journal*, vol. 8, no. 1 (1987), p. 21.

Returns to Scale

The cost, in dollars per kilowatt, of constructing new capacity is characterized by economies of scale; that is, construction costs per kilowatt of capacity decline as the size of the unit increases. As larger units were constructed, however, utilities discovered that down-time was as much as 5 times greater for units larger than 600 megawatts than for units in the 100-megawatt range. The time required for units to cool and heat up is directly related to the mass of the unit and partly related to the greater complexity of the larger units. The last progression, in the late 1950's and 1960's, of technical change involved the development of the supercritical boiler, which achieved a pressure above 3,200 pounds per square inch. However, after reaching a 63-percent share in new installations during 1970 through 1974, the share of supercritical boilers fell to 6 percent in 1981 and 1982. The abandonment of supercritical technology resulted mainly from unanticipated maintenance problems with the higher pressure boilers.[73]

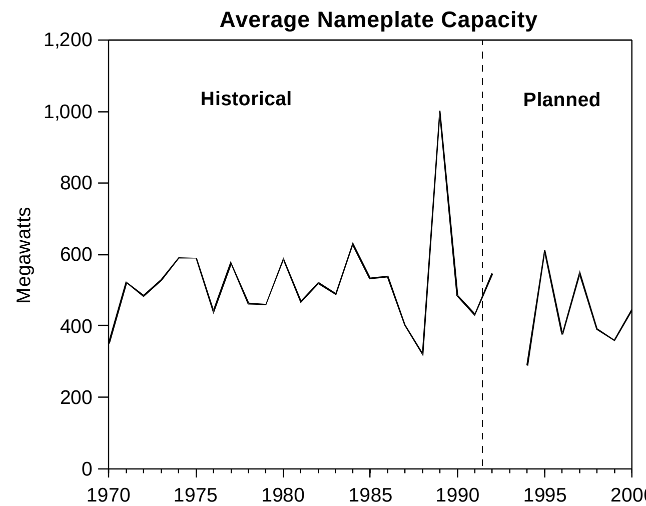
The movement of new coal-fired steam units to larger capacities continued through 1975 (Figure 16). The average capacity of new units in 1974 and 1975 was almost 600 megawatts. After that time, however, the limits on thermal efficiency and economies of scale, along with uncertainty of demand, resulted in fewer units becoming operational through the 1980's. The coal-fired units planned between 1992 and 2000 include 24 units with an average capacity of 409 megawatts, lower than the 506-megawatt average capacity for the 231 units that became operational between 1976 and 1988.

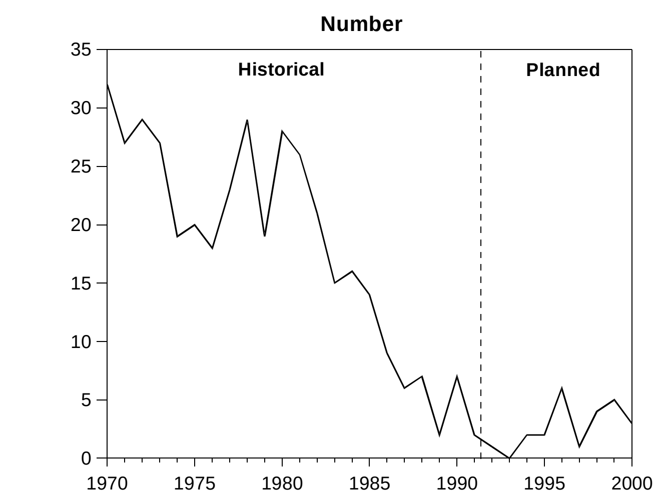
Initially, increasing returns to scale for central station electricity generating units contributed to the dominance of electric utilities and the decline of nonutilities. While these returns to scale were being exploited by utilities, productivity increased and electricity prices declined. In the 1970's, however, even larger generating units no longer produced electricity at lower costs. Many of them developed serious maintenance problems. Increasing returns ceased to be a source of cost and price declines.

Nonutility Scale

Most existing nonutility steam turbine capacity, since it is employed for cogeneration of electric energy and another form of energy and sized for an industrial application, is much smaller than utility steam turbine capacity. From 1973 to 1991, the average capacity of nonutility-owned steam turbines without fluidized-bed boilers increased steadily. In 1991, 45 nonutility units

Figure 16. Average Nameplate Capacity and Number of Utility-Owned Coal-Fired Steam Turbine Units by Historical or Planned Start of Operation, 1970-2000





Notes: ●Nameplate capacity is used instead of net summer capability because net summer capability is not collected for nonutilities. ●No coal-fired units are planned for 1993. ●The year is that in which the unit generator starts or plans to start operation; start operation is when the generator first becomes available to provide electricity to the grid. ●Data include active and previously retired units. ●Data shown in Table C8.

Source: Energy Information Administration, Form EIA-860, “Annual Electric Generator Report” (1991).

[73]Robert J. Gordon, "Forward Into The Past: Productivity Retrogression In The Electric Generating Industry," Working Paper No. 3988, National Bureau of Economic Research (February 1992), p. 11.

with steam turbines but without fluidized-bed boilers became operational, with an average capacity of 42 megawatts.[74] The average for planned capacity additions from 1992 through 1995 just about maintains that level at 41 megawatts for steam turbines without fluidized-bed boilers (Figure 17).

A few steam turbines using fluidized-bed combustion technology were installed by nonutilities in 1950 and in 1962. In a fluidized-bed combustor, the bottom of the firebox is filled with inert granular particles of sand, limestone, or ash. Air blown up through orifices in the floor of the firebox turns the particles into a mass similar to bubbling molten lava, a “fluidized bed.” Heat from the burning fuel, although it may comprise less than one percent of the material in the bed, can make all the inert particles red hot. The direct contact of the flowing particles, with each other and with the boiler walls or tubes, transfers heat within the bed and from the bed to the surrounding walls or tubes. This direct contact allows a higher rate of heat transfer than is possible in a conventional boiler. Even very low-quality fuel can be burned, such as low-grade coal, urban refuse, or even wet sludge, which could not be burned in any conventional fireboxes.

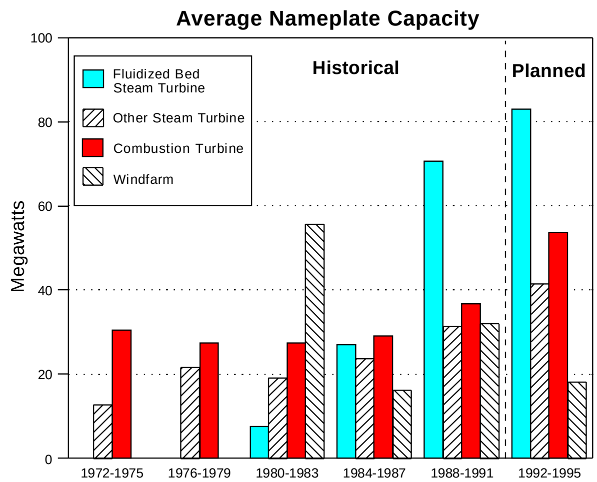
It was not until 1982 that more fluidized-bed units were again added. From 1982 through 1991, the average capacity of fluidized-bed units increased rapidly to 72 megawatts for 4 units in 1991. The average capacity for the 19 units planned to begin operating in 1992 through 1995 increases to 83 megawatts (Figure 17). Nonutilities continue to install considerably more steam turbines without fluidized beds than with them, but the fluidized-bed turbines have larger average capacity.

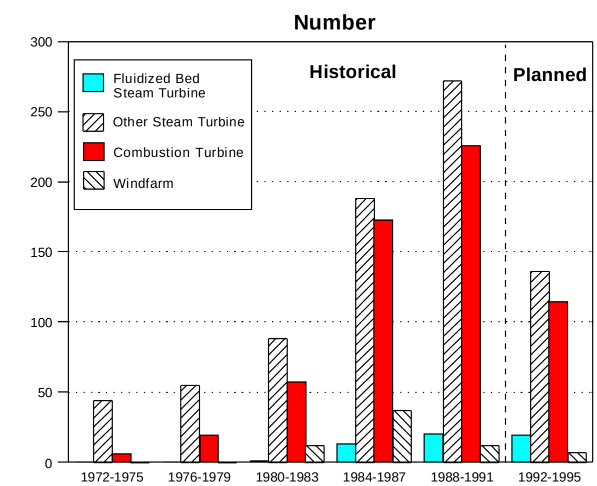
Nonutilities have considerably more steam turbines using fluidized-bed combustion than utilities. Utilities have installed 7 fluidized bed units, some of which were installed recently for demonstration purposes to

One of the Nation's largest coal-fired generating stations is Ohio Power's General J.M. Gavin plant. The plant has two 1,300-megawatt units which began operation in 1974 and 1975.

[74]The mean nameplate capacity is given for the prime mover rather than for the energy source, since the latter can change by substitution of fuels, such as wood for coal, in dual-fired units. Many fossil-fueled nonutility generating units are able to switch from one fossil fuel to another when fuel supply is interrupted or when there is a price advantage to switching to another fuel. Some nonutilities are also able to switch from fossil fuels to renewables. Many units are able to burn two or more different fuels at one time or can be converted to burn different fuels.

Figure 17. Average Nameplate Capacity and Number of Nonutility-Owned Units by Selected Prime Mover and Historical or Planned Start of Operation, 1972-1995





Notes: •Calculated from 1991 preliminary data. •Includes plants of 5 or more megawatts only. •Combined cycle units are included with their constituent prime movers. •Other steam turbine units include conventional steam, combined cycle steam, nuclear steam, geothermal steam, and solar steam. •The year is that in which the unit generator starts or plans to start operation; start operation is when the generator first becomes available to provide electricity to the grid. •Data include active units and units retired in 1989 or later. •Data shown in Table C9.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

determine their feasibility. The average capacity for fluidized-bed units at utilities is 127 megawatts, which is larger than at nonutilities. Utilities have 3 fluidized-bed units planned for around the turn of the century with a nameplate capacity of 200 megawatts each.

The average installed capacity of nonutility-owned combustion turbines increased above 40 gigawatts in 1990, in part due to the availability of larger turbines with greater efficiency.[75] From 1992 through 1995, planned units are expected to be even larger (Figure 17). The number of combustion turbines installed and planned at nonutilities is somewhat less than the number of steam turbines. For wind turbines, more began operation in 1985, when 17 farms with an average capacity of 12 megawatts were first available to provide electricity to the transmission grid, than in any other year. In the four years between 1988 and 1991, a total of 12 windfarms with an average size of 32 megawatts began operation. Seven windfarms with an average size of 18 megawatts are planned to start operation between 1992 and 1995.

[75]In 1990, 95 percent (13.9 gigawatts) of the nonutility combustion turbine operating capacity was located at facilities that were either QF or non-QF cogenerators.

5. Future Trends in the Electric Power Industry

Utility and Nonutility Plans for New Capacity

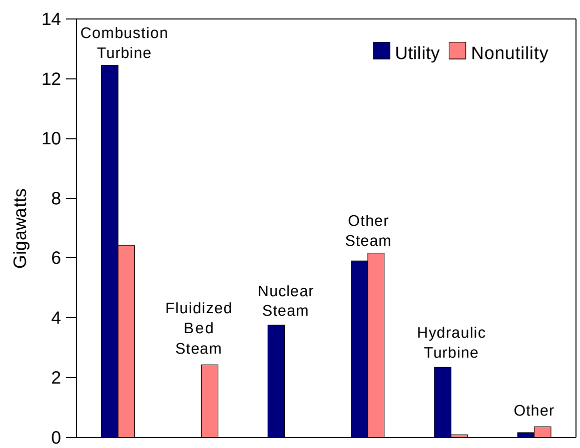
As long as the price that nonutilities receive for the power they produce is greater than their costs, they will continue to enter the electric power generation market. Because the type of generating capacity most often built by nonutilities requires a relatively short construction period, their construction plans for more than a few years into the future are subject to considerable uncertainty. The changes brought about by the Energy Policy Act of 1992 (EPACT) further increase the uncertainty about future plans. Therefore, this report examines only the 5-year plans for new capacity additions, and these plans are expected to change. At the end of 1991, planned capacity additions for non-utility generation facilities from 1992 to 1996 totaled 15 gigawatts, which would increase nonutility installed generating capacity by 31 percent, to 66 gigawatts. Combustion turbines and other steam plants are planned for 81 percent of the new nonutility capacity additions (Figure 18). The majority of this new capacity (64 percent) will be owned by cogenerator QFs; 12 percent will be owned by small power producers. Overall, if these plans are fulfilled in 1996, the proportional shares of capacity ownership by the different types of nonutilities will remain relatively stable (Figure 19).

Until 1990, utility installed capacity additions were much greater than those of nonutilities. In 1990 and 1991, nonutilities installed more new capacity than utilities, and they plan to do so in 1992. Between 1993 and 1996, utilities are planning more capacity additions than nonutilities (Figure 20). There are, however, three reasons that future nonutility additions might be understated. First, nonutilities, unlike utilities, are not required to announce plans for meeting future load. Second, leadtimes for the types of plants usually constructed by nonutilities are shorter than for those types usually constructed by utilities. Finally, the recent passage of EPACT will lead to many new opportunities for nonutilities, the scope of which is unsettled at the present time.

Issues and Uncertainties

The changing structure of the electric power industry has several implications for electricity production and consumption. Two issues of general concern are discussed here: the reliability of the Nation's electricity supply and the effects on wholesale trade of electric power.

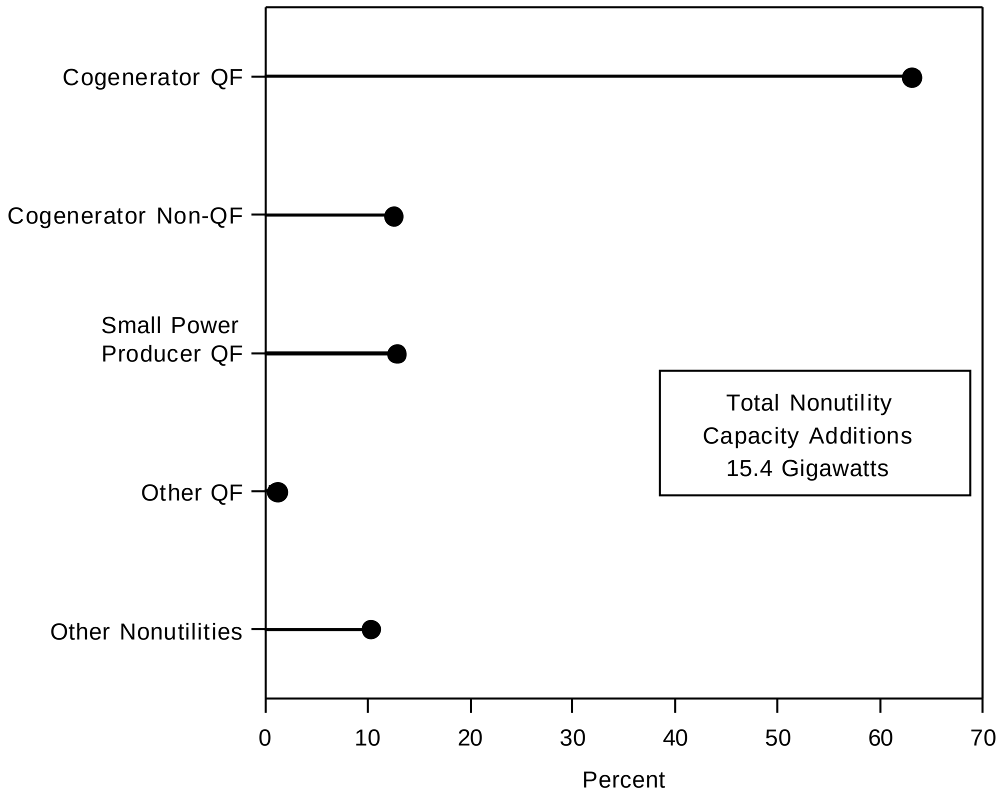
Figure 18. Planned Nameplate Capacity Additions for Electricity Generating Facilities by Prime Mover, 1992-1996



Notes: •Nonutility additions are preliminary data. •Nonutility additions include plants of 5 or more megawatts only. •For nonutilities, a planned unit must have obtained either (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, *or* (3) financial closure on the facility. Because nonutility facilities generally have required shorter leadtimes to finance and build than utility facilities, and because utilities are required to plan for future load, nonutility plans for facilities are likely to be less comprehensive than those for utilities, especially for later years. •For utilities, a planned unit must only be "utility authorized." •Combined cycle units are included with their constituent prime mover. •Utility other steam units include 4.6 gigawatts of conventional steam and 1.3 gigawatts of combined cycle steam. Nonutility other steam units include 3.5 gigawatts of conventional steam, 2.4 gigawatts of combined cycle steam, and 0.2 gigawatts of geothermal steam. •Data shown in Table C3.

Source: **Utility Data**: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" (1991). **Nonutility Data:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

Figure 19. Shares of Planned Nameplate Capacity Additions for Nonutility Electricity Generating Facilities by Type of Facility, 1992-1996



Notes: •Data are preliminary. •Includes plants of 5 or more megawatts only. •For nonutilities, a planned unit must have obtained either (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, *or* (3) financial closure on the facility. Because nonutility facilities generally have required shorter leadtimes to finance and build than utility facilities, and because utilities are required to plan for future load, nonutility plans for facilities are likely to be less comprehensive than those for utilities, especially for later years. •Other QF capacity includes facilities that are both cogenerators *and* small power producers. •Data shown in Table C3.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

Reliability

Currently, most generating capacity is still owned and operated by utilities, which also own and operate their transmission and distribution systems. However, the growing share of nonutility capacity poses a potential challenge to power system operators by reducing the direct control they have over coordinated operation and planning of generation and transmission. Adjusting the power output of generators to follow load fluctuations is a fundamental function in reliable power system operation. The amount of adjustment required depends on system conditions including anticipated load changes and availability of other generators. The spinning reserves"[76] required to regulate outputs are typically a small percentage of load. Load following is usually shared by as many units as possible with each operating at slightly below capacity. This allows rapid response to load fluctuations and minimizes the stress on individual units.

Nonutility suppliers are unlikely to bear the costs of contributing to load following unless specific arrangements are made. Since a generator participating in load following operates below its rated capacity some of the time, an indirect cost results when payment is based on total energy output. Participation in load following also slightly reduces a unit's fuel efficiency and tends to increase its maintenance requirements and to reduce its life, creating direct costs. Therefore, nonutilities are likely to operate at a fixed power output and not under automatic generation control.[77]

[76]Spinning reserves are generating units operating below their rated levels.

[77]Office of Technology Assessment, U.S. Congress, *Electric Power Wheeling and Dealing; Technological Considerations for Increasing Competition*, OTA-E-409 (Washington, DC, May 1989), p. 131.

Figure 20. Planned Nameplate Capacity Additions for Electricity Generating Facilities, 1992-1996

Notes: •Nonutility additions are preliminary data. •Nonutility additions include plants of 5 or more megawatts only. •For nonutilities, a planned unit must have obtained either (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, *or* (3) financial closure on the facility. Because nonutility facilities generally have required shorter leadtimes to finance and build than utility facilities, and because utilities are required to plan for future load, nonutility plans for facilities are likely to be less comprehensive than those for utilities, especially for later years. •For utilities, a planned unit must only be "utility authorized." •Data shown in Table C4.

Source: **Planned Utility Capacity:** Energy Information Administration, *Inventory of Power Plants in the United States 1991*, DOE/EIA-0095(91) (Washington, DC, October 1992), p. 14. **Planned Nonutility Capacity:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

Following daily, weekly, and seasonal cycles in load is also an important element of system operation. Generators increase or decrease their output and undergo planned maintenance outages to follow actual or predicted loads. Performing economic dispatch and scheduling unit commitment are central to minimizing the operating costs of power systems. At present, most nonutility suppliers schedule and dispatch their own generation. This approach will become increasingly less economical, however, as the fraction of supply that is not under the direct control of electric utilities increases. Therefore, many nonutility suppliers are developing operating agreements that give electric utilities increased control over unit scheduling and, in some cases, dispatch.[78]

Maintaining security of supply by preparing for continued operation after equipment failure or other disturbances and restoring service after outages are also required for reliable power system operation. Electric utilities maintain security of supply by assuring that there is enough excess capacity available to provide spinning and ready reserves,[79] and by coordinating of scheduled outages of generation and transmission. Along with the coordination relays and circuit breakers used to isolate failed or overloaded components, power system operators seek to ensure that no failure will result in cascading outages.

The North American Electric Reliability Council (NERC) operating guidelines require each region or

[78]Office of Technology Assessment, U.S. Congress, *Electric Power Wheeling and Dealing,* p. 133.
[79]Ready reserves include generating units and interruptible loads available within 10 minutes.

subregion to have spinning and ready reserves equal to the loss of generation resulting from the most severe failure of a single generating unit or transmission line.[80] The ready reserves must be able to respond rapidly when needed and are in addition to the spinning reserves scheduled for load following. As long as the capacity purchased from nonutilities is no larger than the largest existing utility generator, higher levels of reserves for security should not be required.

Planning for supply security operations requires cooperation among all participants, and contract terms need to be established. Engineering problems involving both generators and transmission components and system problems that depend on complex interactions between interconnected systems and their components are hard to anticipate. All generating capacity must be under the control of a control area operator in order to assure a rapid response to occasional emergencies and system restoration following outages.

Reliance on nonutility suppliers also changes traditional long-term planning. A competitive supply market may increase uncertainty about the long-term availability and performance of supplies. The ability of the non-utility owner to complete construction of the generating unit on time is uncertain, especially if the owner has financial problems.

The process of developing contracts will be instru-mental in communicating needs and defining the obligations of nonutility suppliers and the power system. Long-term contracts can help ensure that non-utilities meet power system needs by specifying prices and performance criteria related to system reliability, including penalties for failure to perform.

Renewable resources used by nonutilities to produce electricity have reliability concerns which limit their use for power system needs. For example, the unpredictability of wind patterns and velocities can affect wind powered generators, clouds can affect the intensity of sunlight reaching solar thermal panels, and patterns and levels of precipitation can affect hydro-electric generators. Renewable resources for electricity generation present an additional type of reliability and planning challenge, due to the natural variation of their power sources, in comparison to conventional resources. Technologies such as geothermal are exceptions to this general rule. Nonutility generators that use fossil fuel (coal, natural gas and oil) as a source of fuel generally can be used for continuous power, except for outages (planned and unplanned) due to the inavailability of the generator.

In 1991, natural-gas-fired electric power generation totalled almost 400 billion kilowatthours. Natural gas is expected to fuel a large share of new capacity at both utilities and nonutilities in the coming years.

Scheduling and controlling the flow of power between utilities are fundamental to interconnected power systems. Scheduling transactions requires analyzing both the economic merit of and the physical ability to perform these transactions, as in the case of unit commitment and the dispatch of a utility's own supplies. Insufficient generation under automatic generation control and unit commitment scheduling may result in poor regulation or increased inadvertent interchange. With nonutility suppliers, increasing the number of transactions requires additional metering, telemetry, and telephone communication for automatic generation control. This is true for wheeling between control areas as well as within them.

Wholesale purchases from nonutility sources are a relatively recent development, and there is little experience to demonstrate conclusively the long-term reliability of such suppliers.[81] The experiences of utilities to date with qualifying facilities indicate that the suppliers have operated reliably. Utilities and State regulators with experience in purchasing power from

[80]Office of Technology Assessment, U.S. Congress, *Electric Power Wheeling and Dealing*, p. 134.
[81]U. S. General Accounting Office, "Potential Effects of Amending the Public Utility Holding Company Act," Report to the Chairman, Subcommittee on Energy and Power, Committee on Energy and Commerce, House of Representatives, GAO/RCED-92-52 (Washington, DC, January 1992), p. 17.

nonutilities have taken steps to ensure the reliability of their source through selection criteria and / or the terms of nonutility wholesale power contracts.

According to NERC, the majority of interruptions in electricity service are caused by failures in local distribution systems and not by outages of specific generating units. By using reserve generating units within their systems or by purchasing power from others, utilities can usually compensate for the temporary loss of a generator without affecting service to consumers.[82]

Utilities, as well as State regulators, have taken steps to ensure that nonutility power purchases include project selection criteria and contract terms that promote reliability. The utilities usually require the following topics to be addressed in nonutility supply contracts:

- Demonstrated feasibility of the project,
- Security deposits against project failure,
- Utility control of supplier's output,
- Penalties for failure to comply with the utility's operating requirements,
- The right to purchase a failed plant, and
- Limits on the debt that a supplier can use for project financing.[83]

Utilities claim that their nonutility wholesale suppliers have proven to be reliable sources. Southern California Edison, which received 29 percent of its electricity from nonutility sources in 1990, indicated that, overall, nonutility wholesale suppliers operated reliably. Pacific Gas and Electric, which received about 12 percent of its electricity from nonutility sources in 1990, indicated that these sources were highly reliable and that their operators were knowledgeable about the system. In addition, Virginia Power, which received 9 percent of its electricity from nonutility suppliers in 1990, also indicated satisfaction with the reliability of its non-utility wholesale suppliers.[84]

NERC has established operating guidelines consisting of minimum operating specifications that both utility and nonutility generators must follow to assure the continued reliability of the Nation's bulk electric system. The guidelines specify technical standards and operating procedures to ensure system reliability and control. NERC requires the coordination of all generating units within a specific control area, and its guidelines for incorporating nonutility wholesale suppliers call for utilities to include interconnecting requirements between the facility and the utility system and the information and communication agreements needed between the utility and the nonutility supplier. The consideration of these factors will help to ensure that nonutility wholesale facilities will operate reliably and will not compromise the overall reliability of the Nation's electricity system.[85]

Bulk Power Trade and Transmission Capacity

Bulk power trade is wholesale trade or transmission of electricity by entities that are not the final consumers of the electricity. Such trade commonly occurs between utilities and between nonutilities and utilities. The total volume of U. S. bulk power trade equals more than one-half of the electricity sold to consumers in retail trade by utilities.[86] There are three types of wholesale transactions: sales, exchanges, and wheeling. Bulk power sales are wholesale trade of electricity in exchange for money. Exchanges are wholesale trade of electricity in exchange for electricity at another time. Wheeling is the transportation of electricity from one place to another by a third party to accomplish the sale or exchange of electricity between two other parties that are not interconnected.

Since many nonutilities are not connected or franchised to serve final consumers, when they produce electricity for sale to others, they must find a way to deliver it to their customers. The way usually leads through a utility via a bulk power transaction. Electric power purchases by utilities from nonutilities have been increasing at the astonishing average annual rate of 31 percent since 1986. Since the recent enactment of EPACT, which opens up the transmission system, the differences in the average cost of producing electricity from State to State could expand wholesale markets to unprecedented levels. The primary reason is that there would be a shakeout toward economic equilibrium as a result of the different plant mixes and plant ages from State to State. This potential for growth has raised concerns that the electric power transmission grid, which transports electricity over long distances, might be affected deleteriously.

[82]U. S. General Accounting Office, "Potential Effects of Amending the Public Utility Holding Company Act," p. 18.
[83]U. S. General Accounting Office, "Potential Effects of Amending the Public Utility Holding Company Act," pp. 18-19.
[84]U. S. General Accounting Office, "Potential Effects of Amending the Public Utility Holding Company Act," pp. 19-20.
[85]North American Electric Reliability Council, "Integrating Non-Utility Generators" (Princeton, NJ, January 1992).
[86]Energy Information Administration, "U.S. Wholesale Electricity Transactions," *Electric Power Monthly*, DOE / EIA-0226(91 / 04) (Washington, DC, April 1991), p. 1.

The 1992 Energy Policy Act gives FERC the authority to open up the transmission system. This law may have considerable effects on the future structure of the electric power industry.

Does the transmission grid have enough capacity to carry additional electricity from nonutilities? NERC has predicted that, in the summer of 1992, "portions of the transmission system will continue to be loaded near their limits *to accommodate economy transfers of electricity"* (italics added).[87] Economy transfers of electricity are those that are made to reduce the total cost of producing electricity; they are not required for the system to operate. Without the economy transfers, near-limit loading of these portions of the system would not occur. In addition, the capacity of the transmission system is a function of, among other things, the actual flows of electric current over the system. In some circumstances, increasing the flow of electricity actually increases the capacity of the system. This is especially true for generators geographically located near load centers. Technological advances are another source of relief for the transmission system. For example, thyristor switches, solid-state devices much faster than circuit breakers, have recently been installed to control a series capacitor bank on a 345-kilovolt transmission line by the Appalachian Power Company.[88] The thyristors will increase the capacity of the line.

Another concern is large shocks to the transmission system, for example, when a large generator goes down. To the extent that nonutilities tend to use smaller generators than utilities, a shift toward more nonutility generation would decrease the possibility of these problems.

The bulk power transmission grid is a complex system that must be continuously monitored and controlled, and nonutilities must be required to meet whatever technical standards are necessary for safe and effective operation of the grid. In its recent study, the Office of Technology Assessment concluded:

> Concerns that the bulk power system (generation and transmission) is inherently incompatible with competition [in generation] do not appear to be well founded. The system can be made to work under any of the institutional / regulatory arrangements considered in this study. Problems and issues will arise with widespread competition, but they will be much less technical than political and institutional.[89]

[87]Similar statements have been made by NERC for several years. North American Electric Reliability Council, *1992 Summer Assessment* (Princeton, NJ, May 1992), p. 2.
[88]"Two Installations to Test Adjustable Series Compensation," *Electrical World* (June 1992), pp. 55-60.
[89]Office of Technology Assessment, U.S. Congress, *Electric Power Wheeling and Dealing* (Washington, DC, May 1989), p. viii.

6. Conclusion

The changing structure of the electric power industry reversed direction dramatically about a decade ago. Before then, electric utilities were expanding their domination of, and nonutilities were becoming increasingly minor participants in, the production of electricity in the United States. Their control of the industry was based largely on their monopoly position as owners and operators of the wholesale and retail electric power transmission and distribution system, much of which was derived from the franchises granted to utilities by State and local governments. The utilities did not inappropriately or illegally prohibit nonutility producers from using the transmission and distribution system, but their monopoly of electric power transportation and retail sales effectively discouraged nonutilities from entering the wholesale and retail markets for electricity.

A number of events during the 1970's, culminating in the enactment of the Public Utility Regulatory Policies Act of 1978, created an environment in which nonutilities have reemerged as important electric power producers. However, the renewed growth of nonutilities is still in its nascent stage. The nonutility sector is quite small and includes many companies new to the electric power generation business. It is not guaranteed that this sector will grow to a sizable share of the industry, as simplistic extrapolations of current trends would suggest. Electric utilities continue to be the dominant sector of the electric power industry, and State and Federal regulations are still a major factor in the industry. The continued growth of nonutilities will depend as much on the actions of utilities and regulators as on their own actions and the effects of Federal legislation. Given the expected resurgent need for capacity additions in the 1990's, utilities may yet regain their dominance of new generating capacity.

Each of the four major participants in the electric power industry—electric utilities, nonutilities, State and Federal regulators, and Congress—will have some influence over the future structure of the industry. The issues facing nonutilities are viability and reliability. Nonutilities must demonstrate their continued viability by meeting their commitments to provide electric power and by satisfying their financial obligations, and they must demonstrate that they can extend their participation in the wholesale power transmission grid without degrading its reliability. If they falter in either area, their continued expansion will be jeopardized.

The issue facing utilities is their ability to adapt to the new, more competitive circumstances of the electric power industry. Given the major changes that have occurred in the industry, utilities must accommodate them, or they will play a diminishing role in electric power supply. The issue facing State and Federal regulators and Federal lawmakers is how to design the regulatory and legal framework of the electric power industry so that the industry will provide electricity to meet the demands of all consumers-residential, commercial, and industrial-in an economically efficient manner. Without this framework, electric power will cost too much to produce and may not be capable of meeting the needs of a growing economy.

While still quite small, the nonutility sector of the electric power industry has grown dramatically in the past decade, in part through its use of renewable technologies such as solar reflectors.

Cover Photo:

Top Left: Baltimore Refuse Energy Systems, Baltimore, Maryland; Top Right: Ocean State Power, Burrillville, Rhode Island; Bottom Left: Nelson Dewey Power Plant, Cassville, Wisconsin; Bottom Right: Perry Nuclear Power Plant, Perry, Ohio.

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Cover Photo:

Top Left: Baltimore Refuse Energy Systems, Baltimore, Maryland; Top Right: Ocean State Power, Burrillville, Rhode Island; Bottom Left: Nelson Dewey Power Plant, Cassville, Wisconsin; Bottom Right: Perry Nuclear Power Plant, Perry, Ohio.

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Appendix A

Form EIA-867, “Annual Nonutility Power Producer Report”

Appendix A

Form EIA-867, “Annual Nonutility Power Producer Report”

Explanatory Notes

The Form EIA-867 is a legally mandated survey of all existing and planned nonutility electric generating facilities in the United States with a total nameplate capacity of 5 or more megawatts. Every 3 years, data are collected from facilities that have a nameplate of 1 or more megawatts, but less than 5 megawatts, to check on their existence. 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 on the facility.

The form consists of Schedules I, “Identification and Certification”; Schedule II, “Generating Facility Information (For Facilities 1 Megawatt or More)”; Schedule IIIA, “Generating Facility Information (For Facilities 5 Megawatts or More)”; Schedule IIIB, “Generating Facility Information (For Facilities 25 Megawatts or More)”; and Schedule IV, “Electric Generator Information (For Facilities 5 Megawatts or More).” Completion of a schedule is based on size, or total capacity, of the generators at the facility. The reporting requirements by facility size are as follows: facilities that are 1 megawatt or more, but less than 5 megawatts, complete only Schedules I and II (for 1989 through 1991 reporting, a report is only required for facilities that did not report in a previous year); facilities that are 5 megawatts or more, but less than 25 megawatts, complete Schedules I, II, IIIA, and IV annually; facilities that are 25 megawatts or more complete the entire form (Schedules I through IV) annually.

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

The Form EIA-867 was implemented in December 1989 to collect data as of year-end 1989. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The form and instructions are included in this appendix for reference. For more information on the form see Energy Information Administration, *Electric Power Monthly/April 1992,* DOE/EIA-0226(92/04) (Washington, DC, April 1993), pages 15 through 18.

Appendix B

Respondents to Form EIA-867, “Annual Nonutility Power Producer Report,” 1991

Appendix B

Respondents to Form EIA-867, "Annual Nonutility Power Producer Report," 1991

Table B1. Respondents to Form EIA-867, "Annual Nonutility Power Producer Report," 1991

Company Name	State
A E Staley Manufacturing Company	IL
Abitibi-Price Corporation	MI
Ada Cogeneration Limited Partnership	CA
Adolph Coors Company	CO
Afton Energy, Inc.	WA
Ag Processing, Inc.	IA
Ag-Energy, Inc.	NY
Agrico Chemical Company	LA
Agrilectric Power Partners, Limited	LA
Air Products & Chemicals, Inc.	PA
Alabama Pine Pulp Company, Inc.	AL
Alabama River Pulp Company, Inc.	AL
Alaska Pulp Corporation	AK
Albany Cogeneration Associates Limited Partnership	MA
Alexandria Power Associates	NH
Alice Falls Hydro	NY
Alison Gas Turbine Division of General Motors	IN
Altamont Cogeneration Corporation	TX
Altamont Energy Corporation	CA
Altamont-Midway, Limited	CA
Alternative Energy, Inc.	ME
Altresco-Pittsfield, Limited Partnership	MA
Altresco/Lynn	CO
Aluminum Company of America	PA
Alvarado Hydro Facility	CA
Alyeska Seafoods, Inc.	AK
American Bituminous Power Partners	CA
American Crystal Sugar Company	MN
American Optical Company	MA
American Ref-Fuel Company	TX
American Tractebel	NH
Amoco Chemical Company	TX
Amoco Oil Company	IL
Amoco Production Company	CO
Amoco Production Company	TX
Amoco Research	IL
Amtrak Corporation	DC
Anadarko Petroleum Corporation	CA
Anheuser-Busch, Inc.	MO
Applied Energy, IncCA	
Aquenergy Systems, Inc.	CT
Arcadian Corporation	LA
Arcadian Fertilizer, Limited Partnership	TN
Archibald Power Company	KY
Archer Daniels Midland Company	IL
Arco Alaska, Inc.	AK
Arco Generation, Inc.	ID
Arco Products Company	CA
Arco Wilmington Calciner	CA
Argico Cogeneration Corporation	CA
Argonne National Laboratory	ID
Arrowhead Cogeneration Company	NJ
Atlantic Energy Systems, Inc.	NY
Aves Hamilton, Inc.	NJ
Aziscohos Hydro Company, Inc.	CT
ACE Cogeneration Company	CA
AES Corporation	VA
AT&T Communications	GA
AT&T Credit Corporation	NJ
B & W Tobacco Company	GA
Badger Creek Limited	TX
Bangor-Pacific Hydro Associate	ME
Baptist Memorial Hospital	FL
Barber Dam Hydroelectric	UT
Bay County Energy Systems, Inc.	FL
Bayou Cogeneration Plant	TX
Bear Creek Hydro Limited Partnership	CT
Bear Mountain Cogeneration, Inc.	TX
Beardslee Corporation	NY
Beaver Creek Hydro, Inc.	ID
Beaver Falls Municipal Authority	PA
Beaverwood Joint Venture	ME
Beebee Island Corporation	NY
Beechwood Energy, Inc.	PA
Bethlehem Steel Corporation	PA
Big Valley Lumber Company	CA
Billings Generation, Inc	ID
Binghamton Cogeneration Limited Partnership	NJ
Bio-Energy Corporation	NH
Bio-Gen Torrington, Limited Partnership	CT
Biogen Power, Inc.	AZ
Biola University	CA
Biomass One, Limited Partnership	OR
Black River Hydro Associates	NY

See notes at end of table.

Table B1. Respondents to Form EIA-867, “Annual Nonutility Power Producer Report,” 1991 (Continued)

Company Name	State
Cargill Fertilizer, Inc.	FL
Cargill, Inc.	TN
Cargill, Inc.	IA
Carrizo Solar Corporation	NM
Carson Energy, IncCA	
Celanese Engineering Resins, Inc.	TX
Central Oregon Irrigation District	OR
Chalk Cliff Cogen Limited	TX
Chambers Cogeneration Limited Partnership	MD
Champion International Corporation	CT
Chapel Hill Properties, Inc.	OH
Chemstar	AZ
Chesapeake Paper Products Company	VA
Chevron Chemical Company	WY
Chevron Refinery	HI
Chevron USA, Inc.	CA
Chilkoot Lumber Company	AK
Chugach Forest Products	AK
Cimarron Chemical, Inc.	TX
Citation Oil & Gas Corporation	OK
City & County of Denver	CO
City of Akron	OH
City of Boulder	CO
City of Fort Smith	AR
City of Harrisburg	PA
City of Honolulu	HI
City of Leclaire	IA
Black River Hydro Corporation	NY
Black River Limited Partnership	NC
Blandin Paper Company	MN
Blue Mountain Forest Products, Inc.	OR
Boise-Kuna Irrigation District	ID
Bonneville Pacific Corporation	UT
Boott Hydropower, Inc.	MA
Borden Chemical Company	LA
Bowater, Inc.	TN
Brady Power Partners	NV
Bridgewater Power Company, Limited Partnership	NH
Brookhaven Energy Center	CA
Brush Cogeneration Partners	CO
Bucknell University	PA
Burney Forest Products	CA
Burney Mountain Power	CA
BAF Energy, Inc.	CA
BASF Corporation	NJ
BIT Manufacturing, Inc.	TN
BP Chemicals-Green lake	TX
BP Oil Company	LA
Caithness King	CO
Calciner Industries, Inc.	LA
Calderon Energy Company	OH
California Almond Growers Exchange	CA
California Energy Company, Inc.	NE
California Institute of Technolgy	CA
CalWind Resources, Inc.	CA
Cannon Energy Corporation	CA
Capital District Energy Center	VA
Carbon/Graphite Group	TX
Cardinal Cogen	CA
City of Lewiston	ME
City of Long Beach	CA
City of New Martinsville	VA
City of Portland	OR
City of Spokane	WA
Clear Lake Cogeneration Limited Partnership	TX
Co Generation Company	OR
Co-Gen II	OR
Coal Dynamics Corporation	VT
Coalinga Cogeneration Company	CA
Coastal Refining & Marketing, Inc.	TX
Cobb County Water System	GA
Coca-Cola Company	GA
Coca-Cola Foods	TX
Cogen Energy Technology Limited Partnership	NY
Cogen Lynchburg, Inc.	TX
Cogen Technologies NJ Venture	TX
Cogeneration Michigan Associates Limited partnership	MI
Cogeneration National Corporation	CA
Cogeneration Technology & Development Company	CO
Cogeneration, Inc.	UT
Cogenerative Electric Power Corporation	VA
Cogentrix of North Carolina, Inc.	NC
Cogentrix of Pennsylvania, Inc.	PA
Cogentrix of Richmond, Inc.	VA
Cogentrix of Rocky Mount, Inc.	NC
Cogentrix-Virginia Leases Corporation	VA
Colebrook Hydroelectric	CT
Collins Pine Company	CA
Colmac Energy, IncCA	
Colonial Sugars, Inc.	LA
Colorado Power Partners	CO
Colstrip Energy Limited Partnership	ID
Colton Hydro Corporation	NY
Commercial Union Capital Group	NY
Commonwealth Atlantic Limited Partnership	NY
Commonwealth Cogen Partner Limited Partnership	TX
Community Central Energy Corporation	PA
Conoco, Inc.	TX
Conserv, Inc.	FL
Consolidated Hydro Maine, Inc.	CT
Consolidated Hydro New Hampshire, Inc.	CT
Consolidated Hydro New York, Inc.	CT
Consolidated Hydro Vermont, Inc.	PA
Consolidated Minerals, Inc.	FL
Consolidated Papers, Inc.	WI
Consolidated Rail Corporation	PA
Container Corp of America	PA
Container Corporation of America	FL
Container Corporation of America	OH
Continental Energy Associates	PA
Copolymer Rubber & Chemical Corporation	LA
Copper Range Company	MI
Coram Energy Group, Limited	CA
Cornell University	NY
Corona Energy Partners, Limited	TX
Coso Energy Developers	NE

See notes at end of table.

Table B1. Respondents to Form EIA-867, “Annual Nonutility Power Producer Report,” 1991 (Continued)

Company Name	State
Coso Finance Partners	NE
Coso Power Developers	NE
CoGen Lyondell, Inc.	TX
CoGen Power, Inc.	TX
Craven County Wood Energy Limited Partnership	NY
Crown Energy, Limited Partnership	SC
Crystal Springs, Inc.	UT
Cyprus Silver Bay Power Corporation	MN
CAPCO Management Group	CA
CCF-3	CT
CDM Hydroelectric Company	CO
CEJA Corporation	OK
CF Industries, Inc.	FL
CFR Bio-Gen Corporation	FL
CHI-Cedar Draw, Inc.	CT
CHI-Combie Dam South	CT
CHI-Felt Dam, Inc.	CT
CHI-Pigeon Cove, Inc.	UT
CITGO Petroleum Corporation	OK
CMI Energy Conversion Systems, Inc.	OK
CNG Energy Company	PA
CTV Management Group	CA
D/R Hydro Company	PA
Daggett Leasing Corporation	CA
Dahowa Hydro	NY
Dakota County	MN
Dan River, Inc	VA
Dartmouth College	NH
Dartmouth Power Associates Limited Partnership	MA
Daw Forest Products Company	OR
Deferiet Corporation	NY
Del Ranch, Limited Partnership	CA
Delano Energy Company, Inc.	MA
Detroit Resource Recovery Facility	MI
Dexzel, Inc.	CA
Diamond Carpets	GA
Diana-Dolgeville Corporation	NY
Diashowa America Company, Limited	WA
Dietrich Drop Hydroelectric	UT
Difwind Farms, Limited	CA
Digital Equipment Corporation	GA
Digital Equipment Corporation	MA
Dinuba Energy, Inc.	CA
Dixie Valley Joint Venture	CO
Dodge Falls Associates Limited Partners	NY
Domco Energy, Inc.	AL
Dominion Energy, Inc.	VA
Doswell I, Inc.	CA
Double 'C' Limited	TX
Douglas County	OR
Dow Chemical Company	TX
Dow Chemical Company	LA
Dow Chemical Company	MI
Dow Corning Corporation	MI
Downeast Peat L P Power Plant	ME
Dunn/Seco Partners	MI
Dutchess County Resource Recovery Agency	NY
E I DuPont De Nemours & Company	DE
Eagle & Phenix Hydro Company, Inc.	CT
Eagle Point Cogen Partnership	VA
East Georgia Cogeneration	DC
East Norfolk Hydro Corporation	NY
Eastman Gelatine Corporation	MA
Eastman Kodak Company	NY
Ebensburg Power Company	OH
Econo Technologies, Inc.	MA
El Paso Natural Gas Company	NM
Elkem Metals Company	PA
Elmore Limited	CA
Empire Lumber Company	ID
Encogen Four Partners Limited Partnership	TX
Endless Energy Corporation	ME
Energy Development & Construction Corporation	CA
Energy Engineering, Inc.	TN
Energy Growth Partnership I	MD
Energy Ingenuity Company	CO
Energy Initiatives, Inc.	NJ
Energy Resources & Logistics, Inc.	MD
Energy Tactics, Inc	NY
Enpex Corporation	CA
Enron Power Corporation	TX
Enserch Development Corporation	TX
Enterprise Products Company	TX
Erving Paper Mills, Inc.	MA
Escalante MicroEnergy Cogeneration, Inc.	UT
Ethacoal North Dakota Corporation	TX
Everett Energy Corporation	MA
Exxon Company USA	TX
Exxon Company USA	CA
EEA I, Limited Partnership	DC
EEA II, Limited Partnership	DC
EEA III, Limited Partnership	DC
EF Oxnard, Inc.	CA
EFFR, Inc.	CA
EPC Power Corporation	PA
ER&L-Duplin, Inc.	MD
EUA/Onsite, Limited Partnership	CA
EUI Management PH, Inc.	PA
Fairfield Energy Venture, Limited Partnership	ME
Fairhaven Power, Inc.	CA
Falcon Seaboard Oil Company	TX
Far West Electric Energy Fund, Limited Partnership	UT
Farmers Union Marketing & Processing Association	MN
Farmland Hydro, Limited Partnership	FL
Fayette Energy Corporation	CA
Federal Paper Board Company	GA
Felts Mills Corporation	NY
Fieldcrest Cannon, Inc.	NC
Fina Oil & Chemical Company	TX
Finch, Pruyn & Company, Inc.	NY
Fish Lake Geothermal Project	CA
Flambeau Paper Company	WI
Florida Crushed Stone Company	FL
Florida State Hospital	FL
Flowind Corporation	CA
Ford Motor Company	MI

See notes at end of table.

Table B1. Respondents to Form EIA-867, "Annual Nonutility Power Producer Report," 1991 (Continued)

Company Name	State
Formosa Plastics Corporation	TX
Fort Howard Corporation	WI
Foster Wheeler Power Systems, Inc.	NJ
Fragosvan Enterprises, Inc.	CA
Franklin Heating Station	MN
Freeport-McMoRan Resource Partners-Limited Partnership	LA
Fresno Landfill Gas Corporation	TX
Friant Power Authority	CA
Frito-Lay, Inc.	TX
Fulton Cogeneration Associates	NY
FMC Corporation-Lithium Division	NC
FPB Cogeneration Partners Limited Partnership	CA
FSC Paper Corporation	IL
Galena Air Force Base	AK
Gas Recovery Systems, Inc.	CA
Gaston County	NC
Gaylord Container Corporation	CA
Gaylord Container Corporation	IL
General Chemical Corporation	WY
General Electric Company	MA
General Electric Erie Power Plant	PA
General Foods Corporation	DE
General Motors Corporation-CPC Pontiac	MI
General Motors-Powertrain Division	MI
General Peat Resources	FL
Geneva Steel	UT
Georgia-Pacific Corporation	GA
Geothermal Energy Partners Limited	CA
Giant Industries, Inc.	NM
Gilberton Power Company	PA
Gillette Company	MA
Gilman Paper Company	GA
Gilroy Energy Company, Inc.	CA
Glendon Energy Company	PA
Goodwin Hydroelectric	CT
Goodyear Tire & Rubber Company	TX
Goodyear Tire & Rubber Company	OH
Gorbell Thermolectron Power Company	MA
Grace Industries, Inc.	CA
Grand River Equities, Inc.	MI
Granite Road Cogen, Inc.	TX
Graniteville Company-Enterprise Division	SC
Graniteville Company-Sibley Division	GA
Grayling Generating Station Limted Partnership	MI
Great Falls Hydroelectric Company	NY
Great Northern Paper, Inc.	ME
Greensboro Lumber Company	GA
GEO East Mesa Electric Company	CA
GEO East Mesa Limited Partnership	CA
GSF Energy, Incorporated	PA
GWF Power Systems Company, Inc.	CA
GWF Power Systems Limited Partnership	CA
Hadson Corporation	CA
Hamakua Sugar Company, Inc.	HI
Hannawa Corporation	NY
Harbor Cogeneration Company	CA
Hardee Power Partners Limited	FL
Harding University	AR
Hartford Hospital CCF-1	CT
Hartford Steam Company	CT
Hastings Lock & Dam	MN
Hawaiian Coml. & Sugar Company, Limited	HI
Hawaiian Electric Renewable Systems, Inc.	HI
Hawaiian Independent Refineries, Inc.	HI
Haypress Hydroelectric, Inc.	CA
Hemphill Power & Light Company	MA
Hercules, Inc.	MO
Hercules, Inc.	GA
Herrings Hydro Corporation	NY
Hershel L Webster	GA
Hershey Foods Corporation	PA
High Falls Corporation	NY
High Sierra Limited	TX
Highland Hydro Construction, Inc.	CA
Higley Corporation	NY
Hillsborough Hydroelectric Limited Partnership	NY
Hilo Coast Processing Company	HI
Hoechst Celanese Corproation	VA
Hoffman LaRoche, Inc.	NJ
Hoffman LaRoche, Inc.	NJ
Hopewell Cogeneration, Inc.	TX
Howden Wind Parks, Inc.	CA
Hudson Lumber Company	CA
Hydro Development Group, Inc.	NY
HL Power Company	MI
Illinois Institute of Technology	IL
Imperial Holly Corporation	TX
Imperial Resources Recovery Associates	NY
Indeck-Corinth Limited Partnership	IL
Indeck-Energy Services of Silver Springs, Inc.	IL
Indeck-Ilion Limited Partnership	IL
Indeck-Kirkwood Limited Partnership	IL
Indeck-Olean Limited Partnership	IL
Indeck-Oswego Limited Partnership	IL
Indeck-Yerkes Limited Partnership	IL
Indeck-Yonkers Limited Partnership	IL
Indiana University of Pennsylvania	PA
Inforum Associates	GA
Inghams Corporation	NY
Inland Container Corporation	IN
Inland Steel Company	IL
Inter Power of Pennsylvania	PA
Intercontinental Energy Corporation	MA
International Paper Company	AR
International Power Systems	GA
International Turbine Research, Inc.	CA
Interpower of New York, Inc.	NY
Interstate Paper Company	GA
Intex Fuels & Chemicals Corporation	UT
Iowa State University	IA
Isabella Partners	CA
Islip Resource Recovery Agency	NY
IBM Corporation	CA
IMC Fertilizer, Inc.	FL
IPT SRI Cogeneration, Inc.	CA

See notes at end of table.

Table B1. Respondents to Form EIA-867, "Annual Nonutility Power Producer Report," 1991 (Continued)

Company Name	State
ITT Rayonier, Inc.	GA
J M Huber Corporation	TX
Jackson Valley Energy Partners Limited Partnership	CA
James River Cogeneration Company	VA
James River Corporation of Virginia	VA
Jefferson County Industrial Development Agency	NY
Jefferson Smurfit Corporation	IL
Jefferson Smurfit Corporation	FL
John Deere Dubuque Works	IA
John Deere Harvester Works Company	IL
John Deere Waterloo Works	IA
Joseph Hydro Company, Inc.	CT
Joyce Engineering Company	PA
JRW Associates Limited Partnership	TX
Kaibab Industries	AZ
Kaiser Aluminum & Chemical Corporation	CA
Kamaoa Wind Energy Partners	HI
Kamargo Corporation	NY
Kamine Milford Limited Partnership	NJ
Kamine/Besicorp Alleghany Limited Partnership	NJ
Kamine/Besicorp Beaver Falls Limited Partnership	NJ
Kamine/Besicorp Carthage Limited Partnership	NJ
Kamine/Besicorp Corning Limited Partnership	NJ
Kamine/Besicorp Natural Dam Limited Partnership	NJ
Kamine/Besicorp South Glens Falls Limited Partnership	NJ
Kamine/Besicorp Syracuse Limited Partnership	NJ
Kaweah River Power Authority	CA
Keating Associates	CA
Kekaha Sugar Company, Limited	HI
Kennedy International Airport Cogeneration Partners	NY
Kern Front Limited	TX
Kern Hydro Partners Limited Partnership	AZ
Kern River Cogeneration Company	CA
Ketchikan Pulp Company	AK
Keystone Energy Service Company, Limited Partnership	MD
Kidder Peabody & Company, Inc.	CA
Killingly Energy Limited Partnership	MA
Kimberly-Clark Corporation	AL
Kings Bay Naval Base	GA
Kinneytown Hydro Company, Inc.	CT
Kinzua Energy Company	WA
Koch Refining Company	TX
Koma Kulshan Associates	WA
Koppers Industries, Inc.	PA
Kraft General Foods, Inc.	NY
KES Chateaugay Limited Partnership	NY
KES Kingsburg Limited Partnership	CT
KJC Operating Company	CA
L & J Energy Systems, Inc.	NY
Lachute Hydro Company, Inc.	CT
Lacomb Hydro Limited Partnership	CA
Lafarge Corporation	MI
Lake City Geothermal 1, Limited Partnership	CA
Lake Cogen Limited	CA
Lake Superior Paper Company	MN
Lawrence Hydroelectric Associates	CT
Leathers Limited Partnership	CA
Lederle Laboratories	NY
Lee County Board of County Commissioners	FL
Lehi Cogeneration Association	UT
Lindale Manufacturing, Inc.	GA
Little Falls Hydroelectric Association	NJ
Littlewood Hydroelectric	CT
Loma Linda University	CA
Long Island Cogeneration, Limited Partnership	OR
Long Lake Energy Corporation	NY
Los Angeles County	CA
Los Angeles County Sanitation District	CA
Louisiana Pacific Corporation	TX
Louisiana Pacific Corproation	CA
Louisiana Tech University	LA
Low Line Drop, Inc.	ID
Low Line Rapid Hydroelectric	UT
Lowell Cogeneration Company Limited Partnership	CT
Lower Saranac Hydro Partners L/P	NY
Luz Solar Partners Limited, IX	FL
Luz Solar Partners Limited, VIII	FL
Luzerne County	PA
Lyons Falls Pulp, Inc.	NY
LAX Airport	CA
LFC Power Systems Corporation	OR
LFG Energy, Inc.	NY
LG&E Power Systems	CA
LTV Steel Company, Inc.	OH
M&M Mars, a Division of Mars, Inc	GA
M&M/Mars, Inc.	NJ
Macon Kraft Company	GA
Madison Paper Industries, Inc.	ME
Magic Reservoir Hydroelectric, Inc.	ID
Maine Energy Recovery Company	ME
Malacha Hydro Limited Partnership	ID
Mammoth Pacific, Limited Partnership	CA
Marathon Oil Company	OH
March Point Cogeneration Company	WA
Marlborough Hydro Corporation	ME
Martell Cogeneration Limited Partnership	WA
Mascoma Hydro	NJ
Massachusetts Bay Transmission Authority	MA
Massachusetts Water Resources Authority	MA
Mayflower Energy Partnership	TX
McBryde Sugar Company, Limited	HI
McCallum Enterprises, Inc.	CT
McKittrick Limited	TX
Mead Corporation	OH
Mead Corporation	TN
Mead Paper Corporation	MI
Mecklenberg Cogeneration Limited Partnership	NC
Mecklenburg County	NC
Medical Area Total Energy Plant, Inc.	MA
Mega Renewables	CA
Megan-Racine Associates	NY
Mendota Biomass Power Limited	MA
Mercer Companies, Inc.	NY
Mercer County Improvement Authority	NJ
Merck & Company, Inc.	NJ
Merck & Company, Inc.	VA

See notes at end of table.

Table B1. Respondents to Form EIA-867, "Annual Nonutility Power Producer Report," 1991 (Continued)

Company Name	State
Merck & Company, Inc-Kelco Division	NJ
Merck & Company, Inc-West Point	NJ
Merimil Limited Partnership	ME
Mesquite Project Services	CA
Metlife Capital Credit Corporation	CT
Metro Dade County Resource Recovery Facility	FL
Michigan State University	MI
Mid Set Cogeneration Company	CA
Mid-Continent Power Company, Inc.	OK
Midland Cogeneration Venture Limited Partnership	MI
Midway-Sunset Cogeneration Company	CA
MidAtlantic Energy	PA
Milesburg Energy, Inc.	VT
Miller Brewing Company	NY
Miller Hydro Group, Inc.	ME
Minnosota Mining & Manufacturing Company	MN
Mississippi Baptist Medical Center	MS
Mississippi Chemical Corporation	MS
Mississippi River Alcohol Company	LA
Mobil Oil Corporation	VA
Mojave Cogeneration Company	FL
Mon Valley Energy, Limited Partnershup	MI
Monsanto Company	MO
Montana Department of Natural Resources	MT
Montefiore Medical Center	NY
Montgomery County Incinerator	OH
Moose River Corporation	IL
Moreau Manufactering Corporation	NY
Morgantown Energy Associates	WV
Morton Salt Company	OH
Mosinee Paper Corporation	WI
Mt Lassen Power	CA
Mulberry Energy, Inc.	WA
Mulberry Phosphates, Inc.	FL
Multitrade of Martinsville, Inc.	VA
Multitrade Group, Inc.	VA
Multitrade Limited Partnership	VA
Muskegon Generation, Inc.	ID
MASSPOWER	MA
N B Partners Limited	WV
Nashville Thermal Transfer Corporation	TN
National Steel Corporation	IL
Nelson Industrial Steam Company	LA
Nevada Cogeneration Associates # 1	NV
Nevada Cogeneration Associates # 2	NV
Newman & Company, Inc.	PA
Nissequoque Cogen Partners	NJ
Nitram, Inc.	FL
Nord Kaolin Company	GA
Norman Ross Burgess	CA
North American Chemical Company	CA
North American Rayon Corporation	TN
North Branch Energy Partners Limited Partnership	PA
North Canal Waterworks	CT
North Shore Towers Apartments, Inc.	NY
Northeast Empire Limited Partnership #1	ME
Northeast Landfill Power Joint Venture	MA
Northeastern Power Company	PA
Northumberland Hydro Partners, Limited Partnership	NY
Northwest Pipeline Corporation	CO
Norton Company	MA
Norwood Hydro Corporation	NY
Notre Dame University	IN
NCR Corporation	OH
NYNEX Credit Company	CA
NYSD Limited Partnership	NY
O'Brien Environmental Energy, Inc.	PA
O'Connell Engineering & Financial, Inc.	MA
O'Shanter Resources, Inc.	CN
Oahu Sugar Company, Limited	HI
Oak Creek Energy System, Inc. II	CA
Oakland County	MI
Occidental Chemical Corporation	TX
Ocean State Power	RI
Ocean State Power II	RI
Ogden Projects, Inc.	NJ
Oildale Corporation	CA
Olandis, Inc.	OK
Olin Corporation	CT
Olin Corporation	LA
Omak Wood Products, Inc.	WA
Ontario Cogeneration, Inc.	CA
Opel Springs Hydro	OR
Orange County	CA
Oswego Hydro Partners, Limited Partnership	NY
Otis Hydroelectric Company	ME
Owl Energy Resources, Inc.	CA
Owyhee Irrigation District	OR
Oxbow Geothermal Corporation	FL
Oxbow Power of Beowawe	FL
Oxbow Power of North Tonawanda, New York, Inc.	FL
Oxford Energy Corporation	MI
OESC	CA
OESI Power Corporation	OR
Pacific Bell	CA
Pacific Cogeneration, Inc.	WA
Pacific Generation Company	OR
Pacific Lumber Company	CA
Pacific Oroville Power Company	CA
Pacific Recovery Corporation	CA
Pacific Southwest Realty Company	CA
Pacific Ultrapower Chinese	CA
Packaging Corporation of America	OH
Packaging Corporation of America	TN
Packaging Corporation of America	WI
Palaau Corporation	OR
Palo Alto Landfill Gas Corporation	MA
Panda Energy Corporation	TX
Panguitch Micro Energy Cogeneration Company	UT
Panther Creek Partners	PA
Paper Products Division	ID
Park 500	VA
Parsons Main, Inc.	CA
Pasco Cogen Limited	CA
Pawtucket Power Associates	MA
Paxton Creek Cogen Associates	PA

See notes at end of table.

Table B1. Respondents to Form EIA-867, "Annual Nonutility Power Producer Report," 1991 (Continued)

Company Name	State	Company Name	State
Pedricktown Cogeneration Limited Partnership	NJ	Ryegate Associates	VT
Pelzer Hydro Company, Inc.	CT	S&L Cogeneration Company	TX
Penn-Mark Industries, Inc.	PA	Saguaro Power Company	CA
Pennsylvania Renewable Resources	NY	Salinas River Cogeneration Company	CA
Penobscot Energy Recovery Company	ME	Salt City Energy Venture Limited Partnership	NY
Pepperell Power Associates Limited Partnership	NY	San Diego Central Cooling Company	CA
Petrolia Development Company	TX	San Gorgonio Farms, Inc.	CA
Pfizer, Inc.	CT	San Joaquin Cogen Limited	TX
Phelps Dodge Corporation	NM	San Jose Cogeneration	CA
Phelps Dodge Mining Company	AZ	Sandberg Wind Corporation	CA
Phibro Energy USA, Inc.	CT	Santa Fe Geothermal, Inc.	TX
Philadelphia Thermal Corporation	PA	Santa Rosa Geothermal Company, Limited Partnership	CA
Pine Products Corporation	OR	Sargent Canyon Cogeneration Company	CA
Pinetree Power Tamworth, Inc.	NH	Savannah Foods	GA
Pioneer Mill Company, Limited	HI	School Street Hydro Corporation	NY
Placid Refining Company	LA	Scott Paper Company	PA
Point Arguello Pipeline Company	CA	Sears-Roebuck & Company	OH
Pontook Operating Limited Partnership	NJ	Seawest Energy Group, Inc.	CA
Port Townsend Paper Company	WA	Seawest Industries, Inc.	CA
Potlatch Corporation	CA	Seawest 17, Inc.	CA
Procter & Gamble Company	OH	Seawest 4, Inc.	CA
Project Orange Associates, Inc.	CA	Second Imperial Geothermal Company	CA
Ptarmigan Resources & Energy, Inc.	CO	Selkirk Cogen	MA
Puna Geothermal Venture	HI	Seminole Fertilizer Company	FL
Purdue University	IN	Seven Oaks Land Company, Inc.	NH
PH Glatfelter Company	PA	Shawmut Engineering, Inc.	CA
PPG Industries, Inc	PA	Shell Development Company	TX
PSC Geothermal Services	CA	Shell Oil Company	TX
Quaboag Power Company	MA	Shell Western E & P, Inc.	CA
Quinebaug Partnership	CT	Shelton Landfill Gas Recovery, Resource	
R J Reynolds Tobacco Company	NC	Recovery Assoc Limited Partnership	CT
Radford Army Ammunition Plant	VA	Sid Richardson Carbon & Gas Company	TX
Rapidan Redevelopment Limited Partnership	MN	Sierra Pacific Industries, Inc.	CA
Raymondville Hydro Corporation	NY	Sierra Power Corporation	CA
Regional Disposal Company	WA	Signal Capital Corporation	MA
Regional Waste Systems	ME	Simplot Leasing Corporation	ID
Regulus Stud Mill, Inc.	ID	Simpson Paper Company	CA
Rev Wind Power Partners 1984-1	CA	Sinclair Oil Corporation	WY
Reynolds Metals Company-Sherwin Plant	TX	Sithe Energies Power Services, Inc.	CA
Rhinelander Paper Company	WI	Sitka Sound Seafood	AK
Rhode Island Cogeneration Association	CO	Slate Creek Hydro Associates Limited Partnership	ME
Rhode Island Hospital	RI	Sloss Industries, Inc.	AL
Rhone-Poulenc, Inc.	NJ	Smith Cogeneration, Inc.	OK
Rice University	TX	Smith Falls Hydropower	UT
Richmond Power Enterprises Limited Partnership	VA	Smithland Hydroelectric Partnership Limited	NJ
Rio Grande Cogen, Inc.	TX	Smithtown Energy Center	CA
Rio Grande Sugar Growers Company	TX	Smurfit Newsprint Corporation	CA
Riverbay Corporation	NY	Snider Industries, Inc.	TX
Riverview Energy Systems	MI	Snohomish County	WA
Riverwood International USA, Inc.	LA	Snow Mountain Pine Company	OR
Robbins Resource Recovery Company	PA	Solar Turbines, Inc.	CA
Rock Creek II Hydroelectric	UT	Solid Waste Authority of Palm Beach County	FL
Rock-Tenn	TX	Somersworth Hydropower Associates	CT
Rockwell International Corporation	CA	Sonoco Products Company	PA
Rohm and Haas Delaware Valley, Inc.	PA	Sonoma County Water Agency	CA
Roseburg Lumber Company	OR	South Florida Cogeneration Associates	FL
Royster Phosphates, Inc.	FL	South San Joaquin Irrigation District	CA
Rubenstein Engineering, Inc.	NY	South Valley Power Corporation	CA

See notes at end of table.

Table B1. Respondents to Form EIA-867, "Annual Nonutility Power Producer Report," 1991 (Continued)

Company Name	State	Company Name	State
Southeast Missouri State University	MO	The Lihue Plantation Company, Limited	HI
Southeast Paper Company	GA	The Metropanitan Water Reclamation District-Greater Chicago	IL
Southeastern Oakland County Resource Recovery Authority	MI	The Ohio State University	OH
Southern California Sunbelt Development, Inc.	CA	The University of North Carolina at Chapel Hill	NC
Southwest Texas State University	TX	The University of Texas at Austin	TX
Sparks Regional Medical Center	AR	Thermal Energy Devel Partnership Limited Partnership	NJ
Spartan Mills	SC	Thermo Industries, Inc. of Colorado	CO
Springfield Resource Recovery, Inc.	MA	Thermo Power & Electric, Inc.	CA
St Joe Paper Company	FL	Thomas Oil Company	CA
St Marys Hospital	MN	Thunder Bay Power Company	MI
Star Enterprise	TX	Timber Energy Resources, Inc	FL
Starrett City, Inc.	NY	Topsham Hydro Partners	NY
State of Wisconsin	WI	Toyo Power Corporation	CA
Stateline Power Associates Limited Partnership	CT	Trenton District Energy Corporation	NJ
Sterling Power Partners, Limited Partnership	NY	Tri-Dam Project	CA
Stillwater Corporation	NY	Trigen-Nassau District Energy Corporation	NY
Stone & Webster Development Corporation	MA	Tropicana Products, Inc	FL
Stone Container Corporation	IL	Turners Falls Limited Partnership	IL
Stratton Energy Associates, Limited Partnership	NY	Twin Falls Hydro Associates, Limited Partnership	CT
Sumas Energy, IncWA		TBG Cogen Partners	NY
Summit Energy Storage, Inc.	NY	TBS Properties	GA
Summit Hydropower	CT	TEC 3/5, Inc	CA
Sun Company, Inc.	PA	TES Filer City Station Limited Partnership	MI
Sun Refining & Marketing Company	OH	U S Agri Chemicals Corporation	FL
Sunlaw Cogeneration Partners I	CA	U S Generating Company	MD
Sunnyside Cogeneration Associates	TX	U S West Financial Services, Inc.	CO
Sunnyside Cogeneration Associates	UT	Union Camp Corporation	GA
Sunterra Gas Processing Company	NM	Union Camp Corporation	VA
Sycamore Cogeneration Company	CA	Union Camp Corporation	AL
Synergics, Inc.	MD	Union Camp Corporation	SC
SDS Lumber Company	WA	Union Carbide Corporation	CT
SEI Birchwood, IncGA		Union County Utilities Authority	NJ
SEMASS Partnership	MA	Union Oil Company of California	CA
Tamal Tinton Falls, Inc.	CT	Unisea, Inc.	AK
Tamarack Energy Partners	ID	United Cogen, Inc.	CA
Tampa Department of Sanitary Sewers	FL	United Development Group - Niagara Limited Partnership	SC
Television City Cogen L P	CA	United Power Systems, Inc.	MD
Temple-Inland Forest Products Corporation	TX	United Refining Company	PA
Tenaska III, Inc.	NE	United States Borax & Chemical Corporation	CA
Tenneco Oil Company	CA	United States Department fo Army-Ft Wainwright	AK
Tennessee Eastman Company	TN	United States Department of the Army	IN
Tera Power Corporation	CA	United States Department of Air Force-Eielson AFB	AK
Terra Comfort Corporation	IA	United States Gypsum Company	IL
Tesoro Alaska Corporation	AK	United States Paper Mills Corporation	WI
Tewksbury State Hospital	MA	United States Sugar Corporation	FL
Texaco Exploration & Producing, Inc.	CO	United States Windpower, Inc.	CA
Texaco Exploration & Production, Inc.	TX	United Supply of America	PA
Texaco Refining & Marketing, Inc.	CA	United Supply Corporation	PA
Texas Petrochemicals Corporation	TX	University of AlaskaAK	
Texasgulf, Inc.	TX	University of Colorado	CO
Texasgulf, Inc.	NY	University of Illinois at Chicago	IL
The Arbutus Corporation	CA	University of Massachusetts	MA
The Art Institute of Chicago	IL	University of Medicine & Dentistry of New Jersey	NJ
The Boeing Company	WA	University of Michigan	MI
The Dexter Corporation	CT	University of Missouri	MO
The Dow Chemical Company	MI	University of Northern Iowa	IA
The Dow Chemical Company	CA	University of Oklahoma	OK

See notes at end of table.

Table B1. Respondents to Form EIA-867, “Annual Nonutility Power Producer Report,” 1991 (Continued)

Company Name	State	Company Name	State
University Cogeneration, Inc.	CA	Western Gas Resources, Inc.	CO
UAH-Hydro Kennebec Limited Partnership	NJ	Western Sugar Company	NE
USDOE-SEPA-Westinghouse Savannah River Company	SC	Westinghouse Credit Corporation	PA
USX Corporation	PA	Westinghouse Electric Corporation	PA
Valcan/BN Geothermal Power Company	CA	Westvaco Corporation	NY
Valero Refining Company	TX	Westward Seafoods, Inc.	AK
Vanderbilt University	TN	Westwind Trust	CA
Velcro USA, Inc.	NH	Westwood Energy Properties	TX
Vermont Marble Company	VT	Weyerhaeuser Company	WA
Victory Mills Company, Inc.	NY	Wheelabrator Environmental Systems, Inc.	NH
Viking Energy Corporation	TX	Whitefield Power & Light Company	MA
Vineland Cogeneration Limited Partnership	NJ	Wichita Falls Energy Company Limited	TX
Virginia Turbo Power System I Limited Partnership	CA	Willamette Industries, Inc.	OR
Vulcan Materials Company	AL	Willamina Lumber Company	OR
VMSO IV Corporation	CA	Wilson Power Company	ID
Waialua Sugar Company, Inc.	HI	Windham Energy Recovery	CT
Warbasse Cogeneration Technologies Partnership L P	NY	Windland, Inc.	CA
Ware Energy Corporation	MA	Windpower Partners 1983-1	CA
Ware Hydro	MA	Windsor Machinery Company, Inc.	NY
Warm Springs Forest Products Industries	OR	WindMaster, Inc.	CA
Warren Petroleum Company	TX	Winooski One Partnership	VT
Waste Energy Recovery Systems	MI	Wintec, Limited	CA
Waste Energy, Inc	NC	Wood Power, Inc.	ID
Waste Management of North America, Inc.	IL	Wood Products Division	ID
Watson Cogeneration Company	CA	Woodland Biomass Power, Limited	MA
Watsonville Cogeneration Partnership	CA	WCI Steel, Inc.	OH
Weeks Falls Hydroelectric Project	CT	Yamaha Motor Manufacturing Company	GA
Weirton Steel Division of National Steel Corporation	WV	Yankee Caithness Joint Venture Limited Partnership	NV
West Coast Cogeneration, Inc.	CA	York County Solid Waste and Refuse Authority	PA
West Delaware Hydro Associates	NJ	Young Brothers, Inc.	TX
West Lynn Cogeneration, Inc.	MA	Yuba City Cogeneration Partners, Limited Partnership	CA
West Publishing Company	MN	Yuba-Bear River	CA
West Tennessee High Security	TN	Zephyr Park, Limited	CA
Western Gas Resources, Inc.	CO	Zinc Corporation of America	PA
Western Gas Resources	ND	Zond Systems, Inc.	CA

Notes: •State codes are post office abbreviations. •Respondents in 1991 include those with facilities with a total generator nameplate rating of 5 or more megawatts and respondents with facilities with a total generator nameplate rating of 1 or more megawatts who did not file a report in 1989 or 1990.

Source: Energy Information Administration, Form EIA-867, “Annual Nonutility Power Producer Report” (1991).

Appendix C

Statistics for the Electric Power Industry

Appendix C

Statistics for the Electric Power Industry

Table C1. Shares of Nameplate Capacity[a] at Utilities by Class of Ownership, 1991
(Gigawatts)

Class of Ownership	
Investor-Owned	573.0
State/Municipal/Subdivision[b]	74.8
Federal	65.6
Cooperative	26.5
Total	**740.0**

[a]Nameplate capacity is used instead of net summer capability because net summer capability is not collected for nonutilities.
[b]The State/Municipal/Subdivision category includes utilities owned by States, municipalities, and other political subdivisions (i.e., districts or public agencies within a State that are engaged in the sale, exchange, and/or transmission of electricity).
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-860, “Annual Electric Generator Report.”

Table C2. Ownership Statistics for the Nonutility Sector of the Electric Power Industry, 1991 (Data for Facilities of 5 or More Megawatts)

Nameplate Capacity[a] (Gigawatts)

Type of Facility		Major Industry Group[b]	
Cogenerator Qualifying Facility	28.4	Manufacturing	
Small Power Producer		Chemical	12.1
Qualifying Facility	7.1	Paper	9.0
Both Cogenerator *and* Small Power		Petroleum Refining	3.8
Producer Qualifying Facility	0.6	Other	7.9
Cogenerator Non-Qualifying Facility	6.6	Electric, Gas, and Sanitary Services	10.7
Other Non-Qualifying Nonutilities	5.4	Mining	2.2
		Other[c]	2.5
Total	**48.2**	**Total**	**48.2**

California and Texas Electricity Generation[a] (Billion Kilowatthours)

California Generation by Major Industry Group[b]		Texas Generation by Major Industry Group[b]	
Manufacturing		Manufacturing	
Chemical	2.2	Chemical	28.6
Paper	2.9	Paper	2.1
Petroleum Refining	7.0	Petroleum Refining	9.2
Other	6.0	Other	6.0
Electric, Gas, and Sanitary Services	22.6	Electric, Gas, and Sanitary Services	1.9
Mining	8.9	Mining	0.8
Other[c]	3.4	Other[c]	0.4
Total	**53.0**	**Total**	**49.0**

[a]Data are preliminary.
[b]The classification system used is the Standard Industrial Classification (SIC).
[c]Other includes agriculture, forestry, fishing, transportation, wholesale and resale trade, finance, insurance, real estate, services, and public administration industries.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-867, “Annual Nonutility Power Producer Report.”

Table C3. 1991 Planned Capacity Additions by Prime Mover and Type of Facility for the Electric Power Industry, 1992-1996 (Nonutility Data for Facilities of 5 or More Megawatts)
(Gigawatts)

Nonutility[a]	
Prime Mover	
Fluidized Bed Steam Turbine	2.4
Other Steam Turbine	6.2
Combustion Turbine	6.4
Hydraulic Turbine	*
Nuclear Steam	0.0
Other	0.4
Total	**15.4**
Type of Facility	
Cogenerator Qualifying Facility	9.8
Small Power Producer Qualifying Facility	1.9
Both Cogenerator *and* Small Power Producer Qualifying Facility	0.1
Cogenerator Non-Qualifying Facility	1.9
Other Non-Qualifying Nonutilities	1.6
Total	**15.4**
Utility	
Prime Mover	
Fluidized Bed Steam Turbine	0.0
Other Steam Turbine	5.9
Combustion Turbine	12.5
Hydraulic Turbine	2.2
Nuclear Steam	3.8
Other	0.2
Total	**24.5**

[a]Nonutility data are preliminary.

*Less than 0.05 gigawatts.

Notes: •For nonutilities, a planned unit must have obtained either (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, *or* (3) financial closure on the facility. Because nonutility facilities generally have required shorter leadtimes to finance and build than utility facilities, and because utilities are required to plan for future load, nonutility plans for facilities are likely to be less comprehensive than those for utilities, especially for later years. •For utilities, a planned unit must only be "utility authorized." •Combined cycle units are included with their constituent prime mover. •Utility other steam units include 1.3 gigawatts of combined cycle steam. Nonutility other steam units include 2.4 gigawatts of combined cycle steam and 0.2 gigawatts of geothermal steam. •Sum of components may not equal total due to independent rounding.

Source: **Utility Data:** Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" (1991). **Nonutility Data:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

Table C4. Capacity and Generation Statistics for the Electric Power Industry, 1991 (Nonutility Data for Facilities of 5 or More Megawatts)

Statistic	Utility	Nonutility[a]	Total U.S.
Nameplate Capacity by Census Division[b] (gigawatts)			
New England	23.8	3.9	27.7
Middle Atlantic	84.6	4.9	89.6
East North Central	124.6	5.0	129.6
West North Central	58.7	1.1	59.8
South Atlantic	141.8	7.3	149.0
East South Central	64.2	1.5	65.6
West South Central	107.8	12.1	119.9
Mountain	52.5	1.3	53.8
Pacific Contiguous	78.7	10.6	89.3
Pacific Noncontiguous	3.3	0.6	3.9
Total	**740.0**	**48.2**	**788.1**
Net Generation by Fuel[c] (billion kilowatthours)			
Coal	1,551.2	40.6	1,591.8
Petroleum	111.5	7.8	119.3
Natural Gas	264.2	131.3	395.5
Nuclear	612.6	0.1	612.6
Hydroelectric	275.5	6.2	281.8
Geothermal	8.1	7.7	15.7
Solar	*	0.8	0.8
Wind	*	2.6	2.6
Wood	0.7	33.8	34.5
Waste	1.3	14.0	15.3
Other[d]	--	3.6	3.6
Total	**2,825.0**	**248.4**	**3,073.5**
Planned Capacity Additions by Year[e] (gigawatts)			
1992	2.7	4.8	7.5
1993	4.2	2.5	6.7
1994	5.7	3.0	8.8
1995	6.0	3.4	9.4
1996	5.9	1.7	7.7
Total	**24.5**	**15.4**	**39.9**

[a]Data are preliminary.

[b]Nameplate capacity is used instead of net summer capability because net summer capability is not collected for nonutilities.

[c]Nonutility generation includes self generation and sales to the grid.

[d]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.

[e]For nonutilities, a planned unit must have obtained either (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, *or* (3) financial closure on the facility. Because nonutility facilities generally have required shorter leadtimes to finance and build than utility facilities, and because utilities are required to plan for future load, nonutility plans for facilities are likely to be less comprehensive than those for utilities, especially for later years. For utilities, a planned unit must only be "utility authorized."

*Less than 0.05 billion kilowatthours.

Note: Sum of components may not equal total due to independent rounding.

Source: **Utility Data:** *Capacity by Census Division*—Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095(91) (Washington, DC, October 1992), pp. 21-22. *Generation by Fuel*—Energy Information Administration, *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, DC, forthcoming), p. 31. *Planned Capacity Additions*—Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095(91) (Washington, DC, October 1992), p. 14. **Nonutility Data:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table C5. Electric Power Industry Generation by Census Division and State, 1991 (Nonutility Data for Facilities of 5 or More Megawatts)
(Billion Kilowatthours)

Census Division and State	Utility	Nonutility[a]	U.S. Total
New England	**87.0**	**20.3**	**107.4**
Connecticut	23.6	3.6	27.2
Maine	9.5	7.5	17.0
Massachusetts	35.8	5.2	41.0
New Hampshire	12.7	1.1	13.8
Rhode Island	0.2	W	W
Vermont	5.3	W	W
Middle Atlantic	**325.5**	**24.9**	**350.4**
New Jersey	37.0	6.5	43.5
New York	126.0	7.7	133.8
Pennsylvania	162.4	10.7	173.0
East North Central	**500.5**	**21.4**	**521.9**
Illinios	127.9	2.5	130.3
Indiana	98.2	3.9	102.1
Michigan	94.6	11.5	106.1
Ohio	132.7	1.4	134.1
Wisconsin	47.1	2.2	49.3
West North Central	**221.2**	**3.3**	**224.5**
Iowa	31.2	0.8	32.1
Kansas	32.3	W	W
Minnesota	40.4	1.7	42.1
Missouri	60.1	0.3	60.5
Nebraska	23.0	W	W
North Dakota	27.5	W	W
South Dakota	6.6	--	6.6
South Atlantic	**541.1**	**32.8**	**573.9**
Delaware	7.6	W	W
D.C.	0.2	--	0.2
Florida	130.7	9.0	139.7
Georgia	90.8	5.6	96.4
Maryland	38.2	W	W
North Carolina	83.5	6.0	89.5
South Carolina	69.8	W	W
Virginia	48.9	5.7	54.7
West Virginia	71.3	W	W
East South Central	**257.8**	**9.0**	**266.8**
Alabama	85.1	4.0	89.1
Kentucky	75.5	--	75.5
Mississippi	23.3	2.7	26.0
Tennessee	73.9	2.3	76.3
West South Central	**378.7**	**73.4**	**452.1**
Arkansas	38.4	2.4	40.8
Louisiana	57.2	17.6	74.7
Oklahoma	44.9	4.4	49.3
Texas	238.3	49.0	287.4
Mountain	**249.1**	**5.4**	**254.5**
Arizona	66.8	W	W
Colorado	31.0	1.2	32.2
Idaho	8.3	1.2	9.5
Montana	28.2	W	W
Nevada	21.0	W	W
New Mexico	25.1	W	W
Utah	30.2	W	W
Wyoming	38.7	0.6	38.7
Pacific Contiguous	**252.6**	**55.5**	**308.1**
California	105.0	53.0	158.0
Oregon	46.3	1.0	47.3
Washington	101.4	1.5	102.8
Pacific Noncontigious	**11.6**	**2.3**	**14.0**
Alaska	4.3	0.9	5.2
Hawaii	7.3	1.4	8.7
United States	**2,825.0**	**248.4**	**3,073.5**

[a]Data are preliminary. Some State nonutility data have been withheld to avoid disclosure of individual company data; these States account for less than 5 percent of total United States nonutility generation.

Note: Sum of components may not equal total due to independent rounding.

Source: **Utility Generation:** Energy Information Administration, *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, DC, forthcoming), p. 31. **Nonutility Generation:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).

Table C6. Statistics of the Utility Sector of the Electric Power Industry, 1970-1991

Year	Nameplate Capacity[a] (gigawatts)	Generation (billion kilowatthours)	Generation by Fuel (billion kilowatthours)						Fossil Fuel Prices[b] (dollars per million Btu)			Real Retail Price[c] (real cents per kilowatthour)[d]
			Coal	Nuclear	Natural Gas	Petroleum	Hydro-electric	Other	Coal[e]	Petroleum	Natural Gas	
1970	341.6	1,532	704	22	373	184	248	1	0.31	0.41	0.28	5.7
1971	368.9	1,613	713	38	374	220	266	1	0.36	0.57	0.31	5.8
1972	398.6	1,750	771	54	376	274	273	2	0.38	0.64	0.33	5.8
1973	442.4	1,861	848	83	341	314	272	2	0.41	0.78	0.35	5.7
1974	477.6	1,867	828	114	320	301	301	3	0.71	1.87	0.49	6.6
1975	508.3	1,918	853	173	300	289	300	3	0.82	1.99	0.75	7.0
1976	531.0	2,038	944	191	295	320	284	4	0.85	1.95	1.03	7.0
1977	560.2	2,124	985	251	306	358	220	4	0.95	2.19	1.29	7.2
1978	579.2	2,206	976	276	305	365	280	3	1.12	2.13	1.43	7.2
1979	598.3	2,247	1,075	255	329	304	280	4	1.22	2.98	1.74	7.2
1980	613.5	2,286	1,162	251	346	246	276	6	1.35	4.25	2.20	7.8
1981	634.8	2,295	1,203	273	346	206	261	6	1.53	5.32	2.80	8.2
1982	650.1	2,241	1,192	283	305	147	309	5	1.65	4.83	3.37	8.6
1983	658.2	2,310	1,259	294	274	144	332	6	1.66	4.60	3.47	8.5
1984	672.1	2,416	1,342	328	297	120	321	9	1.66	4.82	3.58	8.1
1985	698.1	2,470	1,402	384	292	100	281	11	1.65	4.24	3.43	8.0
1986	707.7	2,487	1,386	414	249	137	291	12	1.58	2.42	2.35	7.8
1987	718.1	2,572	1,464	455	273	118	250	12	1.51	2.97	2.24	7.5
1988	723.9	2,704	1,541	527	253	149	223	12	1.47	2.41	2.26	7.3
1989	730.9	2,784	1,554	529	267	158	265	11	1.45	2.85	2.36	7.1
1990	735.1	2,808	1,560	577	264	117	280	11	1.45	3.30	2.32	6.8
1991	740.0	2,825	1,551	613	264	111	276	10	NA	NA	NA	6.8

[a]Nameplate capacity is used instead of net summer capability because net summer capability is not collected for nonutilities.

[b]The coal price is the price of all coal and the petroleum price is the price of heavy oil. (Heavy oil includes grade numbers 4, 5, and 6, and residual fuel oils).

[c]Real retail price of electricity sold by electric utilities. Data for 1979 and earlier are for Classes A and B privately owned electric utilities only; data for 1980 and forward are for selected Class A utilities whose electric operating revenues were $100 million or more during the previous year.

[d]Prices are in 1991 dollars, calculated using the implicit GNP price deflator.

[e]Other includes geothermal, solar, wind, waste and wood.

NA = Not available.

Note: Sum of components may not equal total due to independent rounding.

Source: **Capacity:** *1970-1981*—Energy Information Administration, *1982 Annual Energy Review*, DOE/EIA-0384(82) (Washington, DC, April 1983), p. 159. *1982-1991*—Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095 (Washington, DC, 1984 through 1992). **Generation:** *1970-1990*—Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC, June 1992), p. 211. *1991*—Energy Information Administration, *Electric Power Annual 1991*, DOE/EIA-0348(91) (Washington, DC, forthcoming), pp. 14 and 30-31. **Estimated Fuel Prices**: Energy Information Administration, State Energy Price and Expenditure Data System, 1992. **Real Retail Price:** Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC, June 1992), p. 229.

Table C7. Statistics of the Nonutility Sector of the Electric Power Industry, 1970-1991

Year	Nameplate Capacity (gigawatts)	Generation (billion kilowatthours)			Generation by Fuel (billion kilowatthours)					Fossil Fuel Prices[a] (dollars per million Btu)		
		Self-Serving[b]	Grid-Serving[c]	Total	Coal	Natural Gas	Renewable[d]	Waste[e]	Other[f]	Coal[g]	Petroleum[h]	Natural Gas
1970	[i]19	NA	NA	108	NA	[i]NA	NA	NA	NA	0.44	0.46	0.38
1971	19.3	NA	NA	103.2	NA	NA	NA	NA	NA	0.47	0.62	0.41
1972	18.8	NA	NA	104.5	NA	NA	NA	NA	NA	0.51	0.60	0.46
1973	19.4	NA	NA	102.6	NA	NA	NA	NA	NA	0.53	0.73	0.50
1974	19.4	NA	NA	101.6	NA	NA	NA	NA	NA	0.99	1.82	0.67
1975	19.2	NA	NA	85.3	NA	NA	NA	NA	NA	1.28	1.91	0.95
1976	19.1	NA	NA	87.1	NA	NA	NA	NA	NA	1.25	1.90	1.21
1977	19.2	NA	NA	87.5	NA	NA	NA	NA	NA	1.31	2.15	1.48
1978	19.4	NA	NA	79.0	NA	NA	NA	NA	NA	1.46	2.12	1.66
1979	17.4	NA	NA	71.3	NA	NA	NA	NA	NA	1.55	2.76	1.96
1980	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.56	3.69	2.52
1981	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.75	4.48	3.07
1982	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.84	4.46	3.80
1983	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.75	4.38	4.10
1984	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.76	4.73	4.13
1985	22.9	70.2	28.3	98.5	18.2	33.6	28.8	10.9	7.1	1.81	4.24	3.87
1986	25.3	71.3	40.7	112.0	20.5	40.0	32.1	13.9	5.5	1.75	2.51	3.20
1987	30.0	94.0	52.6	146.6	22.3	56.8	42.1	11.4	14.0	1.64	2.87	2.88
1988	33.7	104.1	70.2	174.3	31.9	70.0	46.8	20.4	5.1	1.61	2.34	2.90
1989	40.3	107.2	93.7	200.9	30.4	88.9	59.1	17.8	4.7	1.61	2.75	2.93
1990	45.1	116.3	116.5	232.8	35.3	111.2	63.4	19.5	3.3	1.63	3.10	2.94
1991	50.1	138.7	136.6	275.2	42.5	135.6	71.3	21.4	4.4	NA	NA	NA

[a]Prices for industrial sector only.
[b]Self-serving electricity is consumed by the nonutility.
[c]Grid-serving electricity is resold by utilities to final consumers.
[d]Renewable energy sources include biomass, hydroelectric, wind, solar, and geothermal resources.
[e]Waste energy sources include anthracite culm, blast furnace gas, coke oven gas, digester gas, petroleum coke, refinery gas, refinery oil, sulfur combustion, waste gas, and waste heat.
[f]Other includes petroleum, nuclear, fuel cell, multiple unit projects for which the primary energy source varies among the units, and projects which did not identify primary energy source.
[g]The coal price is the price of steam coal.
[h]The petroleum price is the price of residual fuel oil.
[i]1970 nonutility capacity and generation data are available to whole numbers only.
NA = Not available.

Notes: •Capacity and generation data for 1970 through 1979 represent the industrial sector for plants of 10 megawatts or more only. •Capacity and generation data were not collected for 1980 through 1984. •Capacity and generation data for 1985 through 1991 include all nonutilities. •Sum of components may not equal total due to independent rounding.

Source: **Capacity and Generation:** *1970-1979*—Federal Power Commission, Form 4, "Monthly Power Plant Report." *1985-1990*—Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1991* (Washington, DC, October 1992), pp. 7 and 15. *1991*—Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), pp. 2 and 31. **Generation by Fuel:** *1985-1986*: Edison Electric Institute, *1986 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, July 1988), pp. 78 and 79. *1987-1988*: Edison Electric Institute, *1988 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, April 1990), pp. 55 and 56. *1989-1990*: Edison Electric Institute, *1990 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, December 1991), pp. 55 and 56. *1991*: Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), p. 55. **Estimated Fuel Prices:** Energy Information Administration, State Energy Price and Expenditure Data System, 1992.

Table C8. Average Nameplate Capacity and Number of Utility-Owned Coal-Fired Steam Turbine Units by Historical or Planned Start of Operation, 1970-2000

Year[a]	Coal-Fired Steam: Average Capacity (Megawatts)	Coal-Fired Steam: Number
1970	350.2	32
1971	520.5	27
1972	482.7	29
1973	528.0	27
1974	590.7	19
1975	589.4	20
1976	438.9	18
1977	574.7	23
1978	461.1	29
1979	459.0	19
1980	586.5	28
1981	466.8	26
1982	518.8	21
1983	488.6	15
1984	629.7	16
1985	531.7	14
1986	536.8	9
1987	401.8	6
1988	320.0	7
1989	1,002.8	2
1990	484.1	7
1991	429.8	2
1992	546.0	1
1993	NM	0
1994	288.1	2
1995	612.4	2
1996	374.5	6
1997	546.0	1
1998	390.0	4
1999	358.6	5
2000	443.3	3

[a]The year is that in which the unit generator starts or plans to start operation; start operation is when the generator first becomes available to provide electricity to the grid.

NM = Not meaningful.

Note: Data include active and previously retired units.

Source: Energy Information Administration, Form EIA-860, “Annual Electric Generator Report” (1991).

Table C9. Average Nameplate Capacity and Number of Nonutility-Owned Units by Selected Prime Mover and Historical or Planned Start of Operation, 1972-1995 (Data for Facilities of 5 or More Megawatts)

Year[b]	Fluidized Bed Steam Turbine		Other Steam Turbine[a]		Combustion Turbine		Windfarms	
	Average Capacity (Megawatts)	Number	Average Capacity (Megawatts)	Number	Average Capacity (Megawatts)	Number	Average Capacity (Megawatts)	Number
1972-1975	NM	0	12.7	44	30.4	6	NM	0
1976-1979	NM	0	21.6	55	27.4	19	NM	0
1980-1983	7.5	1	19.1	88	27.4	57	55.6	12
1984-1987	27.0	13	23.7	188	29.1	173	16.2	37
1988-1991	70.7	20	31.4	272	36.7	226	32.0	12
1992-1995	83.0	19	41.5	136	53.7	114	18.2	7

[a]Other steam turbine units include combined cycle steam, nuclear steam, geothermal steam, and solar steam.

[b]The year is that in which the unit generator starts or plans to start operation; start operation is when the generator first becomes available to provide electricity to the grid.

NM = Not meaningful.

Notes: •Calculated from 1991 preliminary data. •Combined cycle units are included with their constituent prime movers. •Data include active units and units retired in 1989 or later.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report" (1991).