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The Changing Structure of the Electric Power Industry 2000: An Update

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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 Administration (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 2000: An Update*. The purpose of this report is to provide a comprehensive overview of the structure of the U.S. electric power industry, focusing on the past 10 years, with emphasis on the major changes that have occurred, their causes, and their effects. It is intended for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

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Executive Summary

The U.S. electric power industry, the last major regulated energy industry in the United States, is changing to be more competitive. In some States, retail electricity customers can now choose their electricity company. New wholesale electricity trading markets, which were previously nonexistent, are now operating in many regions of the country. The number of independent power producers and power marketers competing in these new retail and wholesale power markets has increased substantially over the past few years. To better support a competitive industry, the power transmission system is being reorganized from a balkanized system with many transmission system operators, to one where only a few organizations operate the system. However, the introduction of these new markets has been far from seamless. California, where retail competition was introduced in 1998, has had problems recently. Electricity prices in some parts of the State have tripled and there have been supply problems as well. Although not as severe as California, New York's electricity market has had price spikes which may be attributable to problems in the market design. While some observers argue that deregulation should be scrapped, others argue that deregulation is a noble endeavor and that these problems can be solved with structural adjustments to the markets.

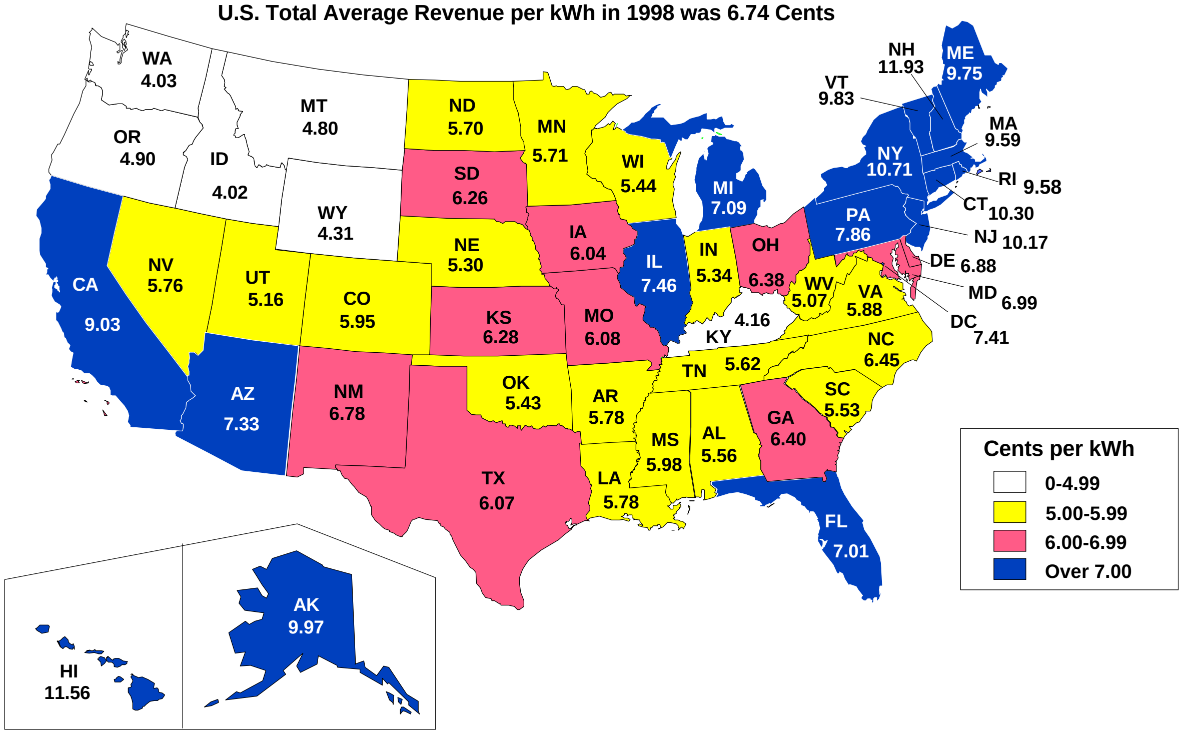
This reorganization is actually the second major structural realignment in the history of the industry. The first occurred during the late 1920s and early 1930s. However, the changes then were mandated by a Federal law that was designed to stop holding company misconduct. Today, the changes that are occurring are not driven by misconduct, but rather by economic and technological factors. In fact, three primary catalysts are driving the current movement toward a restructured electric power industry. First is a general reevaluation of regulated industries and a rethinking of how the introduction of competition might improve efficiencies. The telecommunications and banking industries have been made more competitive, and the electric power industry is being evaluated for similar efficiency gain potential. The second factor driving the restructuring debate is the wide disparity of electricity rates across the United States (Figure ES1). In 1998, consumers in New York paid more than two and one-half times the rates that consumers in Kentucky paid for their electricity. In the western United States, the rates paid by consumers in California were well over twice the rates paid by consumers in Washington. Technological improvements in gas turbines have changed the economics of power production. No longer is it necessary to build a 1,000-megawatt generating plant to exploit economies of scale. Combined-cycle gas turbines reach maximum efficiency at 400 megawatts, while aero-derivative gas turbines can be efficient at scales as small as 10 megawatts. These improvements, involving less capital investment and less time to build capacity, are the third set of catalysts driving restructuring.

Because it provides the capability to move power over long distances, the transmission system is an integral component of the Nation's electric power industry. Through regulatory reform, the Federal Energy Regulatory Commission (FERC) has promoted the development of competitive wholesale power markets and opening the transmission system to all qualified users. Since the late 1980s, FERC has approved more than 850 applications to sell power competitively in wholesale markets. In arguably its most ambitious effort to date, in December 1999, FERC issued Order 2000 calling for electric utilities to form regional transmission organizations (RTOs) that will operate, control, and possibly own the Nation's power transmission system. The potential benefits of RTOs are the elimination of discriminatory behavior in using the transmission system, improved operating efficiency, and increased reliability of the power system.

A number of States have played an active role in promoting retail competition in the electric power industry. Relatively high-cost States have been in the forefront of enacting legislation or making rules to allow retail competition. California and the northeastern States were the first to allow retail competition and encourage consumers to shop for their power suppliers. Other States such as Kentucky and Idaho, whose rates are among the lowest in the country, are not moving as quickly. A recent report issued by Kentucky's Special Task Force on Electricity Restructuring found no compelling reason for Kentucky to move quickly to restructure its electric power industry. As of July 1, 2000,

Figure ES1. Average Revenue per Kilowatthour for All Sectors by State, 1998

U.S. Total Average Revenue per kWh in 1998 was 6.74 Cents



kWh = Kilowatthour.

Note: The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. Sales in deregulated retail electricity markets are not included.

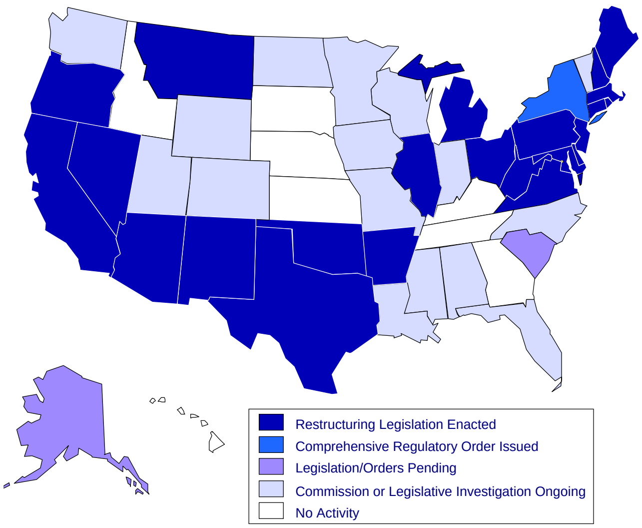
Source: Energy Information Administration, Form EIA-861, “Annual Electric Utility Report.”

24 States and the District of Columbia had enacted legislation or passed regulatory orders to restructure the electric power industry (Figure ES2).

While most of the States have been active in restructuring their own jurisdictions, several bills designed to provide a single Federal framework for wholesale and retail competition have been introduced into the U.S. Congress. These bills address myriad restructuring issues such as reliability, reform of Federal power marketing administrations, a public benefits fund, tax issues, and renewable energy portfolio standards. Extensive hearings and debates have been held to understand the interests and concerns of all parties involved in the industry, and reaching consensus has been an imposing pursuit. The recent price spikes in California will certainly be a topic of discussion as the restructuring debate moves forward. Retail prices in San Diego have tripled in some cases over the summer of 2000 and there have been blackouts in the San Francisco Bay area. Any discussion surrounding new bills will most certainly address mitigation of these price spikes and supply curtailments. In all likelihood, Congress will be involved in these activities for a number of months before any comprehensive restructuring legislation will be passed.

Mergers, acquisitions, and divestitures of power plants have become widespread as investor-owned utilities (IOUs) seek to improve their positions in the increasingly competitive electric power industry. Since 1992, IOUs have been involved in 35 mergers, and an additional 12 mergers are pending approval. One effect of these mergers is that the size of IOUs is increasing. In 1992, the 10 largest IOUs owned 36 percent of total IOU-held generation capacity, and the 20 largest IOUs owned 58 percent of IOU-held generation capacity. By the end of 2000, the 10 largest IOUs will own an estimated 51 percent of IOU-held generation capacity, and the 20 largest will own approximately 72 percent. While the size of the largest IOUs is increasing, because of generation divestitures, they generally own a smaller proportion of total generating capacity than in the past.

Figure ES2. Status of State Electric Utility Deregulation Activity, as of July 2000



Source: Energy Information Administration.

In addition to mergers within the electricity industry, IOUs—seeing growth opportunities in the natural gas industry—are merging with or acquiring natural gas companies, contributing to what is referred to as convergence of the two industries. In the last 3 years, 23 convergence mergers have been completed or are pending.

Influenced predominantly by State-level electricity industry restructuring programs that emphasize the unbundling of generation from transmission and distribution, and in some cases by a desire to exit the competitive power generation business, IOUs are divesting power generation assets in unprecedented numbers. Since late 1997, IOUs collectively have divested or are in the process of divesting 156.5 gigawatts of power generation capacity, representing about 22 percent of total U.S. electric utility generation capacity. Divestiture means that the IOU will either sell its generation capacity to another company or transfer the generation capacity to an unregulated subsidiary within its own holding company structure. As a result of mergers and divestitures during the past few years, the organizational structure of the electric power industry (i.e., the numbers and roles of the industry participants) is changing. The traditional role of the electric utility as a provider of electric power is giving way to the expanding role of nonutilities as providers of electric power. An analysis of electric power data collected by the Energy Information Administration for the period 1992 through 1998 offers the following insights:

- The number of IOUs has decreased by 8 percent (261 in 1992 vs. 239 in 1998), while the number of nonutilities generating electricity has increased by 9 percent (1,792 in 1992 vs. 1,954 in 1998).

- Nonutilities are expanding and buying utility-divested generation assets, causing their net generation to increase by 42 percent (286 million megawatthours in 1992 vs. 406 million megawatthours in 1998) and their nameplate capacity to increase by 73 percent (57 thousand megawatts in 1992 vs. 98 thousand megawatts in 1998). Nonutility capacity and generation will increase even more as they acquire additional utility-divested generation assets over the next few years.

- The nonutility share of net generation rose from 9 percent (286 million megawatthours) in 1992 to 11 percent (406 million megawatthours) in 1998.

- Utilities have historically dominated the addition of new capacity. However, utilities are adding less capacity, while nonutility additions to capacity have been increasing at an average annual rate of nearly 7 percent since 1992. In 1998 alone, the nonutility share of additions to capacity was 82 percent (5,396 megawatts) with utilities adding 1,185 megawatts or 18 percent.

Since 1998, it is expected that these trends have continued.

1. Introduction

Electric power generation in the United States is changing from a regulated industry to a competitive industry. Where power generation was once dominated by vertically integrated investor-owned utilities (IOUs) that owned most of the generation capacity, transmission, and distribution facilities, the electric power industry now has many new companies that produce and market wholesale and retail electric power. These new companies are in direct competition with the traditional electric utilities. Today, vertically integrated IOUs still produce most of the country's electrical power, but that is changing.

The long-standing traditional structure of the industry was based, in part, on the economic theory that electric power production and delivery were natural monopolies, and that large centralized power plants were the most efficient and inexpensive means for producing electric power and delivering it to customers. Large power generating plants, integrated with transmission and distribution systems, achieved economies of scale and consequently lower operating costs than relatively smaller plants could realize. Because of the monopoly structure, Federal and State government regulations were developed to control operating procedures, prices, and entry to the industry in order to protect consumers from potential monopolistic abuses.

Several factors have caused this structure to shift to a more competitive marketplace. First, technological advances have altered the economics of power production. For example, new gas-fired combined cycle power plants are more efficient and less costly than older coal-fired power plants. Also, technological advances in electricity transmission equipment have made possible the economic transmission of power over long distances so that customers can now be more selective in choosing an electricity supplier. Second, between 1975 and 1985, residential electricity prices and industrial electricity prices rose 13 percent and 28 percent in real terms, respectively. These rate increases, caused primarily by increases in utility construction and fuel costs, caused Government officials to call into question the existing regulatory environment. Third, the effects of the Public Utilities Regulatory Policies Act of 1978, which encouraged the development of nonutility power producers that used renewable energy to generate power, demonstrated that traditional vertically integrated electric utilities were not the only source of reliable power.

Competition in wholesale power sales received a boost from the Energy Policy Act of 1992 (EPACT), which expanded the Federal Energy Regulatory Commission's (FERC's) authority to order vertically integrated IOUs to allow nonutility power producers access to the transmission grid to sell power in an open market. FERC's authority to order access was implemented on a case-by-case basis and proved to be slow and cumbersome. To remedy that, FERC issued Order 888 requiring all vertically integrated IOUs to file an open access transmission tariff that would provide universal access to the transmission grid to all qualified users. Order 888 was an important stimulus in the development and strengthening of competitive wholesale power markets, but discriminatory practices regarding access to the transmission grid still remained, and a more effective effort was needed. In December 1999, FERC issued Order 2000 calling for the creation of regional transmission organizations (RTOs), independent entities that will control and operate the transmission grid free of any discriminatory practices. Electric utilities are required to submit proposals to form RTOs from October 2000 through January 2001.

In addition to wholesale competition, retail competition has started in many States. For the first time in the history of the industry, retail customers in some States have been given a choice of electricity suppliers. As of July 1, 2000, 24 States and the District of Columbia had passed laws or regulatory orders to implement retail competition, and more are expected to follow. The introduction of wholesale and retail competition to the electric power industry has produced and will continue to produce significant changes to the industry. These changes are referred to collectively as restructuring.

The purpose of this report is twofold. Part I (Chapters 2 through 4) can be used as a basic reference document for information about the traditional electric power industry before restructuring started, while Part II (Chapters 5 through 9) describes the major causes and events that are changing the industry's structure from a totally regulated monopoly to one where both competition and regulation coexist. Chapter 2 presents an overview of the industry's history from inception to approximately when deregulation and restructuring started. Chapter 3 explains the infrastructure of the industry, detailing its generating, transmitting, and distributing components. It also presents industry-wide statistics depicting how restructuring has changed the composition of the industry. For example, it illustrates the growing importance of nonutility power producers in meeting the Nation's electric power demands. Chapter 4 presents a summary of 21 Federal acts that have directly or indirectly affected the regulation, structure, and operating procedures of the electric power industry since its inception.

Chapter 5 presents a discussion of the causes leading to Federal and State deregulation of power generation and subsequently to restructuring of the electric power industry. Following this, Chapter 6 discusses numerous Federal bills, either initiated in Congress or by the Administration, designed to promote, assign responsibility, or provide guidance to continued deregulation of the industry. This chapter also discusses the debate to repeal the Public Utility Holding Company Act of 1935, and the Public Utility Regulatory Policies Act of 1978, both of which brought significant changes to the industry, but are now considered by some to be obsolete in a competitive electricity industry.

Continuing a discussion at the Federal level, Chapter 7 presents FERC's role in promoting competitive wholesale electric power markets and restructuring the management, operation, and possibly the ownership of the Nation's high voltage bulk power transmission system. Although the bulk power transmission system does not receive wide public attention, it plays a key role in the movement to a competitive industry.

Chapter 8 discusses the roles of individual States in promoting competition and restructuring at the retail level. A summary of the status of each State's restructuring activities is presented along with discussions addressing retail competition in five States. A discussion of the recent problems in the California market is included in this chapter.

Chapter 9 examines IOUs—the largest component of the electric industry in terms of power generation, value of assets, and total revenues—and how they are coping with and preparing for competition through mergers, acquisitions, and power plant divestitures. In many ways these corporate activities, which transfer and / or consolidate ownership and control of the Nation's electric power assets, represent the core of industry restructuring. Readers will also find a discussion of the role of the Federal Government in approving mergers and acquisitions, which has become more important as the number of mergers increases.

Part I:

The U.S. Electric Power Industry as a Regulated Monopoly

2. Historical Overview of the Electric Power Industry

At the beginning of the 20th century, vertically integrated[1] electric utilities produced approximately two-fifths of the Nation's electricity. At that time, many businesses (nonutilities) generated their own electricity. When utilities began to install larger and more efficient generators and more transmission lines, the associated increase in convenience and economical service prompted many industrial consumers to shift to the utilities for their electricity needs. With the introduction of the electric motor came the inevitable development and use of more home appliances. Consumption of electricity skyrocketed along with the utility share of the Nation's generation.

Utilities operated in designated exclusive franchise areas which, in the early years, were usually municipalities. Along with the service area designation came the obligation to serve all consumers within that territory. "The growth of utility service territories . . . brought State regulation of privately owned electric utilities in the early 1900s. Georgia, New York, and Wisconsin established State public service commissions in 1907, followed shortly by more than 20 other States. Basic State powers included the authority to franchise the utilities; to regulate their rates, financing, and service; and to establish utility accounting systems."[2]

The early structure of the electric utility industry was predicated on the concept that a central source of power supplied by efficient, low-cost utility generation, transmission, and distribution was a natural monopoly. Because monopolies in the United States were outlawed by the Sherman Antitrust Act,[3] regulation of the utilities was a necessity. In addition to its intrinsic design to protect consumers, regulation generally provided reliability and a fair rate of return to the utility. The result was traditional rate-based regulation.[4]

Electric utility holding companies[5] were forming and expanding during the early 1900s, and by the 1920s they controlled much of the industry. By 1921, privately owned utilities were providing 94 percent of total generation, and publicly owned utilities contributed only 6 percent.[6] At their peak in the late 1920s, the 16 largest electric power holding companies controlled more than 75 percent of all U.S. generation.[7] Originally formed to reap the benefits (mostly of a financial nature) of centralized ownership of a multitude of subsidiaries, these unregulated holding companies were in a position to abuse their power over their subsidiaries. Sometimes, the result was increased prices paid by consumers of electricity. Because the States could not regulate an interstate holding company, it became apparent that the Federal Government would have to step in. After several large holding company systems collapsed, an investigation by the Federal Trade Commission was ordered, leading eventually to the passage of the Public Utility Holding Company Act of 1935 (PUHCA). Under the provisions of the Act, holding companies became regulated by the Securities and Exchange Commission. Under Title II of PUHCA utilities involved in interstate wholesale marketing or transmission of electric power became regulated by the Federal Power Commission (FPC).[8]

1 A vertically integrated utility is one which engages in generation, transmission, and distribution operations.

2 Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985,* DOE / EIA-0474(85) (Washington, DC, August 1985), p. 3.

3 The Clayton Antitrust Act of 1914 strengthened the Sherman Antitrust Act of 1890.

4 This form of rate setting has been blamed by some groups for removing the incentive for utilities to achieve maximum efficiency in operations and planning, thereby exhibiting the major flaw in this type of regulation and promoting the push for its demise.

5 A holding company is a company that confines its activities to owning stock in and supervising management of other companies. The Securities and Exchange Commission, as administrator of the Public Utility Holding Company Act of 1935, defines a holding company as "a company which directly or indirectly owns, controls or holds 10 percent or more of the outstanding voting securities of a public utility company" (15 USC 79b, par. A (7)).

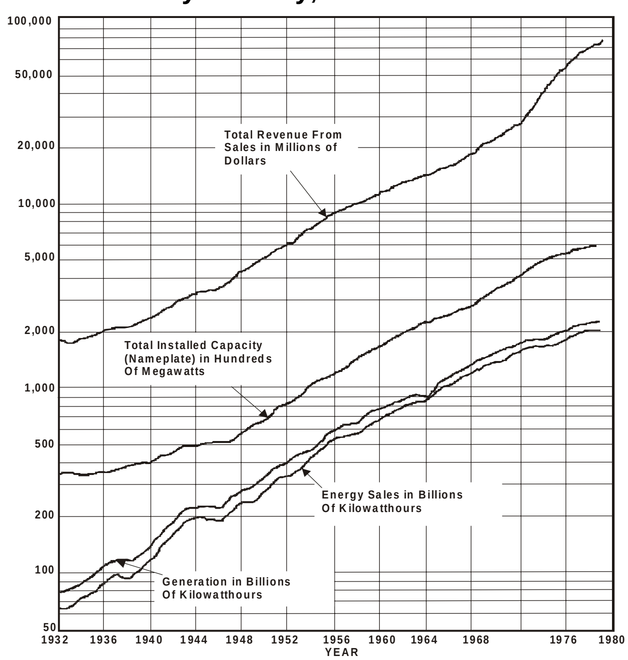
6 Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985,* DOE / EIA-0474(85) (Washington, DC, August 1985), p. 3.

7 *Encyclopedia Americana*, International Edition, Vol. 22 (New York, NY: Americana Corporation, 1977), p. 769.

8 In October 1977, many of the regulatory powers of the FPC were transferred to the Federal Energy Regulatory Commission (FERC).

On October 29, 1929, the U.S. stock market crashed, creating losses of $16 billion for that month—a staggering amount of money in 1929—and leading to the Great Depression. The social and economic well-being of the Nation was severely shaken, but the electric power industry was able to stay adrift of the devastation, and local operating utilities remained solvent. Figure 1 shows that, although the rate of growth in the industry did wane at times during the Depression, the U.S. electric utility industry's capacity, generation, revenues, and sales experienced a healthy growth pattern from 1932 through 1980. Table 1 shows the percentage change between various electric power industry statistics for the years 1932 and 1945, which also demonstrates the robust condition of the industry during that time.

Figure 1. Annual Statistics for the Total Electric Utility Industry, 1932-1980



Source: Electric Utility Systems Engineering Department of the General Electric Company, *Electric Utility Systems and Practices,* ed. Homer M. Rustebakke, 4th ed., Chapter 1, "The Electric Utility Industry" (New York, NY: Wiley & Sons, Inc., 1983), p. 4.

In the years immediately following the onset of the Great Depression, Congress took actions designed to alleviate some of the most acute problems, e.g., unemployment and the plight of farmers. Two of these actions directly and advantageously affected the electric power industry: the development of Federally owned power and the creation of the Rural Electrification Administration (REA). (See inset on page 7.)

During the 1920s and the early years of the Depression, the public became disenchanted with privately owned power and began to support the idea of Government ownership of utilities, particularly hydroelectric power facilities. This disenchantment was chiefly the result of abuses heaped on utilities, and ultimately on their customers, by holding companies,[9] causing the price of electricity to increase. Government-owned hydroelectric power facilities could produce power cheaply and sell it to publicly owned utilities for distribution. This concept was a controversial political issue at the time, with strong arguments on both sides. Many believed that private power did not employ fair operating practices and, therefore, Government-owned power was wholeheartedly supported. Others were opposed to the Government entering the electricity business because they believed that the Government was exploiting hydroelectric sites. Nevertheless, the Federal Government did become heavily involved through the construction and ownership of several massive hydroelectric facilities.

During the presidency of Franklin D. Roosevelt (1933 to 1945), a number of these facilities were built and publicly owned power took a strong hold. President Roosevelt began his New Deal campaign, which was designed to help the American public by providing jobs, and ultimately hope, during the long years of the Depression. As part of the program, he proposed that the Government build four hydropower projects and, within a year after his proposal, his administration began to implement the projects. Large Bureau of Reclamation dams began serving the western States:

- Hoover Dam began generation in 1936, followed by other large projects.
- Grand Coulee, the Nation's largest hydroelectric dam, began operation in 1941.
- The U.S. Army Corps of Engineers flood control dams provided additional low-priced power for preferred customers.

Under the Tennessee Valley Authority Act of 1933, the Federal Government supplied electric power to States, counties, municipalities, and nonprofit cooperatives, soon including those of the REA. The Bonneville Project Act of 1937 pioneered the Federal power marketing administrations. By 1940, Federal power pricing policy was set; all Federal power was marketed at the lowest possible price, while still covering costs. From 1933 to 1941, one-half of all new capacity was provided by Federal and other public power installations. By the end

9 For further details, refer to the subsequent section on The Public Utility Holding Company Act of 1935.

Table 1. Percentage Change Between Various Electric Power Industry Statistics From the Great Depression Through World War II, 1932-1945

	1932	1945	Percent Change
Real GNP (1958 dollars in billions)	154	437	184
Energy consumption (Btu trillions)	18,022	36,030	100
Electricity production (kWh millions)	99,359	271,255	173
Real prices (1958 dollars):			
Electricity (cents/kWh)	7.08	2.89	-59
Oil (dollars per barrel)	2.16	2.04	-6
Coal (dollars per ton)	3.25	5.15	58
Percent electricity produced by:			
Privately-owned utilities	75.0	66.7	–
Publicly-(Government)owned utilities	4.9	15.3	–
Industry and transport	20.1	18.0	–
Production per kW of capacity (kilowatthours)	2,309	4,440	92
Coal equivalent per kWh produced (pounds)	1.5	1.3	-3
Return earned on average capital (percent)	6.3	6.6	5
Return earned on average equity (percent)	7.9	8.2	4
Bond yields (percent)	4.7	2.6	-45
Utility stock index (S&P electric)	16.64	14.94	-10
Industrial stock index (S&P 400)	5.37	14.72	174

Source: L. S. Hyman, *America's Electric Utilities, Past, Present and Future*, Fifth Edition, Public Utilities Reports, Inc. (Arlington, VA, August 1994), p. 113.

of 1941, public power contributed 12 percent of total utility generation, with Federal power alone contributing almost 7 percent.[10] Besides electric power, these dams provided flood control, navigation, area development, and greatly needed work for the unemployed. Even during the Eisenhower Administration's policy of no new starts, Federal power continued to grow as earlier projects came on line.

In the mid-1930s, many homes, farms, and ranches in rural areas were still without lights, indoor bathrooms, refrigerators, or running water. It was too expensive

The Rural Electrification Administration

In an effort to lessen the effects of the Depression on the American farmer, in 1936 “Congress passed the Norris-Rayburn Act, the purpose of which was to ensure a 10-year integrated program for electrifying American farms. To that end, it authorized appropriations of $410 million.”[a] The Federal Government encouraged the growth of rural electricity service by subsidizing the formation of rural electric cooperatives. The Rural Electrification Act of 1936 established the Rural Electrification Administration (REA). Congress authorized it as an independent Federal bureau, and in 1939 it was reorganized as a division of the U.S. Department of Agriculture. The REA undertook a program to provide rural areas and towns with populations under 2,500 with inexpensive electric lighting and power. “To implement those goals, the administration made long-term, self-liquidating loans to State and local governments, to farmers’ cooperatives, and to nonprofit organizations; no loans were made directly to the consumers.”[b] REA-backed cooperatives enjoyed Federal power preference plus lower property assessments, exemptions from Federal and State income taxes, and exemption from State and Federal Power Commission regulation.[c]

[a] M. L. Cooke, *Electrifying the Countryside*, http://newdeal.feri.org/tva/cooke.htm.
[b] Rural Electrification Administration, http://www.infoplease.com/ce5/CE045037.html.
[c] The Rural Electrification Administration has been replaced by the Rural Utilities Service, whose mission is to improve the quality of life in rural America by administering its Electrification, Telecommunications, and Water and Waste Disposal Programs.

[10] Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970*, pp. 2, 24.

for the investor-owned utilities that served the cities to stretch their lines into the countryside, so many areas remained without access to electric power. The Federal Government encouraged the growth of rural electricity service by subsidizing the formation of rural electric cooperatives. The Rural Electrification Act of 1936 established the REA to provide loans and assistance to organizations providing electricity to rural areas and towns with populations under 2,500. REA-backed cooperatives enjoyed Federal power preferences[11] plus lower property assessments, exemptions from Federal and State income taxes, and exemption from State and Federal Power Commission regulation. As a result, by 1941 the proportion of electrified farm homes rose to 35 percent, more than three times that of 1932.[12]

For decades, utilities were able to meet the increasing demand for electricity at decreasing prices. Economies of scale were achieved through capacity additions, technological advances, and declining costs. Of course, the monopolistic environment in which they operated left them virtually unhindered by the worries that would have been created by competitors. This overall trend continued until the late 1960s, when the electric utility industry saw decreasing unit costs and rapid growth give way to increasing unit costs and slower growth.[13] Over a relatively short time, a number of events took place which contributed to the unprecedented reversal in the growth and well-being of the industry: the Northeast Blackout of 1965 raised pressing concerns about reliability; the passage of the Clean Air Act of 1970 and its amendments in 1977 required utilities to reduce polluting emissions; the Oil Embargo of 1973-1974 resulted in burdensome increases in fossil-fuel prices; the accident at Three Mile Island in 1979 led to higher costs, regulatory delays, and greater uncertainty in the nuclear industry; and inflation (in general) caused interest rates to more than triple.

While the industry was attempting to recover from this onslaught of damaging events, Congress designed legislation that would reduce U.S. dependence on foreign oil, develop renewable and alternative energy sources, sustain economic growth, and encourage the efficient use of fossil fuels. One result was the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA became a catalyst for competition in the electricity supply industry, because it allowed nonutility facilities[14] that met certain ownership, operating, and efficiency criteria established by FERC to enter the wholesale market. Utilities initially did not welcome this forced competition, but some soon found that buying generation from a qualifying facility (QF) had certain advantages over adding to their own capacity, especially because of the increasing uncertainty of recovering capital costs. The growth of nonutilities was further advanced by the Energy Policy Act of 1992 (EPACT). EPACT expanded nonutility markets by creating a new category of power producers—exempt wholesale generators (EWGs)—that are exempt from PUHCA's corporate and geographic restrictions. Like QFs, EWGs are wholesale producers that do not sell electricity in the retail market and do not own transmission facilities. Moreover, unlike the nonutilities that qualified under PURPA, EWGs are not regulated and may charge market-based rates, and utilities are not required to buy their power. The growth of EWGs marked another step toward increasing the level of competition in the wholesale electricity market. (For a more detailed description of the purpose and effects of PUHCA, PURPA, and EPACT, see Chapter 4.)

Prior to passage of PURPA in 1979, the electric power industry had been relatively stable for approximately 45 years. Today, however, the industry is undergoing immense change, both structurally and operationally. Having a basic knowledge of how it was originally organized can facilitate understanding its current transitional state. A more detailed account of the industry's history is provided in Appendix A, History of the U.S. Electric Power Industry, 1882-1991. Appendix B, Historical Chronology of Energy-Related Milestones, 1800-2000, lists the major technological and institutional events in the development of the U.S. electric power industry. The following chapter describes its organizational components.

[11] The Federal Government moved quickly in the mid-1930s to, where opportunities appeared, produce and distribute less expensive federally produced electricity to preference customers.

[12] U.S. Bureau of the Census, Historical Statistics of the United States, *Colonial Times to 1970, Bicentennial Edition,* Part 2 (Washington, DC, 1975), p. 827.

[13] Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985,* DOE/EIA-0474(85) (Washington, DC, August 1985), p. 7.

[14] A nonutility is a corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchise service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

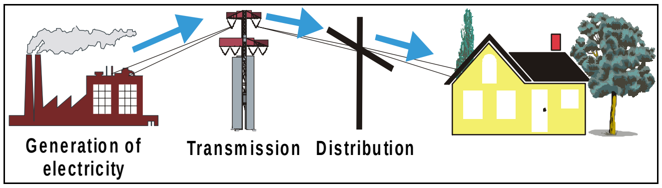
3. The U.S. Electric Power Industry Infrastructure: Functions and Components

Introduction

The transition of the U.S. electric power industry from a regulated monopoly to a deregulated industry where generators of electricity compete for customers is in full swing. Consequently, many aspects of the industry are changing, including its infrastructure. This chapter explains the functions and components (or participants) contained in the infrastructure and uses data collected by the Energy Information Administration (EIA) to reflect the changes that have taken place in the past decade or so. Shifts in the number and ownership of power production facilities, the volume of power generation and capacity, and other areas are also explained.

The fundamental structure of the industry has been based on the vertical integration of utilities, i.e., their involvement in the three functions of power supply. Those functions are *generation*, *transmission*, and *distribution* of electricity (Figure 2). Generation is defined as the production of electric energy from other energy sources. Transmission is the delivery of electric energy over high-voltage lines from the power plants to the distribution areas. Distribution includes the local system of lower voltage lines, substations, and transformers which are used to deliver the electricity to end-use consumers. Prior to detailing the components of power supply along with their characteristics, this chapter will outline the three functions of power supply.

Figure 2. Electric Power Supply Functions



Generation

Generation facilities are currently owned and operated by two categories of companies—utilities and nonutilities.[15] Electric power generators use a variety of prime movers and energy sources to generate electric energy. Prime movers are the engine, turbine, water wheel, or similar machines that drive an electric generator. Energy sources include combustion of fossil fuels, nuclear fission, kinetic energy in water or wind, chemical energy in a fuel cell, and sunlight. Wind, water, sunlight, geothermal energy, biomass, and waste products are renewable energy sources that are considered inexhaustible.

Generating units vary in size. Nuclear and fossil-fuel steam-electric units typically have large capacities with many over 1,000 megawatts (MW), while hydroelectric dams range from less than 1MW to thousands of MW at some of the large Federal dams. Gas turbines, combustion turbines, and combined-cycle units are typically less than 200 MW, but some are larger. Wind and solar plants are relatively small. Distributed generation, which can be installed at or near the customer's site can be quite small, such as rooftop photovoltaic arrays or fuel cells ranging from several to a few hundred kilowatts.

The generating units operated by an electric utility vary by intended usage, that is, by the three major types of load (generally categorized as base, intermediate, and peak) requirements the utility must meet.[16] A base-load generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Base-load units are generally the largest of the three types of units, but they

[15] Electric utilities are defined as either privately owned companies or publicly owned agencies that engage in the supply (including generation, transmission, and / or distribution) of electric power. Nonutilities are privately owned companies that generate power for their own use and / or for sale to utilities and others. The next section of this chapter delineates the types and characteristics of utilities and nonutilities as well as their changing roles in the supply of the Nation's electricity.

[16] The demand for power varies over the day, with about 16 hours of "on-peak" time in the day and about 8 hours of "off-peak" time during the night. Demand for electric power typically reaches its highest peak on very hot or very cold days. At those times, many of the available plants in a region may need to be brought online to meet the high demand.

cannot be brought on line or taken off line quickly. Peak-load generating units can be brought on line quickly and are used to meet requirements during the periods of greatest or peak load on the system. They are normally smaller plants using gas and combustion turbines. Intermediate-load generating units meet system requirements that are greater than base-load but less than peak load. Intermediate-load units are used during the transition between base-load and peak-load requirements.

Types of Generators

Steam Units: Steam-electric (thermal) generating units are typically the large baseload plants. Steam produced in a boiler turns a turbine to drive an electric generator (Figure 3a). Fossil fuels (coal, petroleum and petroleum products, natural gas or other gaseous fuels) and other combustible fuels, such as biomass and waste products, are burned in a boiler to produce the steam. Nuclear plants use nuclear fission as the heat source to make steam. Geothermal or solar thermal energy also produce steam. The thermal efficiency[17] of fossil-fueled steam-electric plants is about 33 to 35 percent. The waste heat is emitted from the plant either directly into the atmosphere, through a cooling tower, or sent to a lake for cooling. A water pump brings the residual water from the condenser back to the boiler.

Gas Units: Gas turbines and combustion engines use the hot gas from burning fossil fuels, rather than steam, to turn a turbine that drives the generator. These plants can be brought up quickly, and so are used as peaking plants. The number of gas turbines is growing as technological advances in gas turbine design and declining gas prices have made the gas turbine competitive with the large steam-electric plants. However, thermal efficiency is slightly less than that of the large steam-electric plants (Figure 3b). The gas wastes are disposed of through an exhaust stack.

Combined-Cycle Units: Combined cycle plants first use gas turbines to generate power and then use the waste heat in a steam-electric generator to produce more electricity. Thus, combined-cycle plants make more efficient use of the heat energy in fossil fuels. New technology is improving the thermal efficiency of combined-cycle plants, with some reports of 50 to 60 percent thermal efficiency (Figure 3c).

Cogenerating Units: Cogenerators, also known as combined heat and power generators, are facilities that utilize heat for electricity generation and for another form of useful thermal energy (steam or hot water), for manufacturing processes or central heating. There are two types of cogeneration systems: bottom-cycling and top-cycling. In a bottom-cycling configuration, a manufacturing process uses high temperature steam first and a waste-heat recovery boiler recaptures the unused energy and uses it to drive a steam turbine generator to produce electricity. In one of two top-cycling configurations, a boiler produces steam to drive a turbine-generator to produce electricity, and steam leaving the turbine is used in thermal applications such as space heating or food preparation. In another top-cycling configuration, a combustion turbine or diesel engine burns fuel to spin a shaft connected to a generator to produce electricity, and the waste heat from the burning fuel is recaptured in a waste-heat recovery boiler for use in direct heating or producing steam for thermal applications (Figure 3d).

Other Units: The kinetic energy in moving water and wind is used to turn turbines at hydroelectric plants and wind facilities to produce electricity. Other types of energy conversion include photovoltaic (solar) panels that convert light energy directly to electrical energy, and fuel cells that convert chemical energy directly to electrical energy.

Energy Sources

Coal: Coal is the Nation's primary fuel for electricity generation, representing 40 percent of the capability,[18] and producing over half (52 percent) of the generation (Figure 4) because coal is used as a baseload fuel.

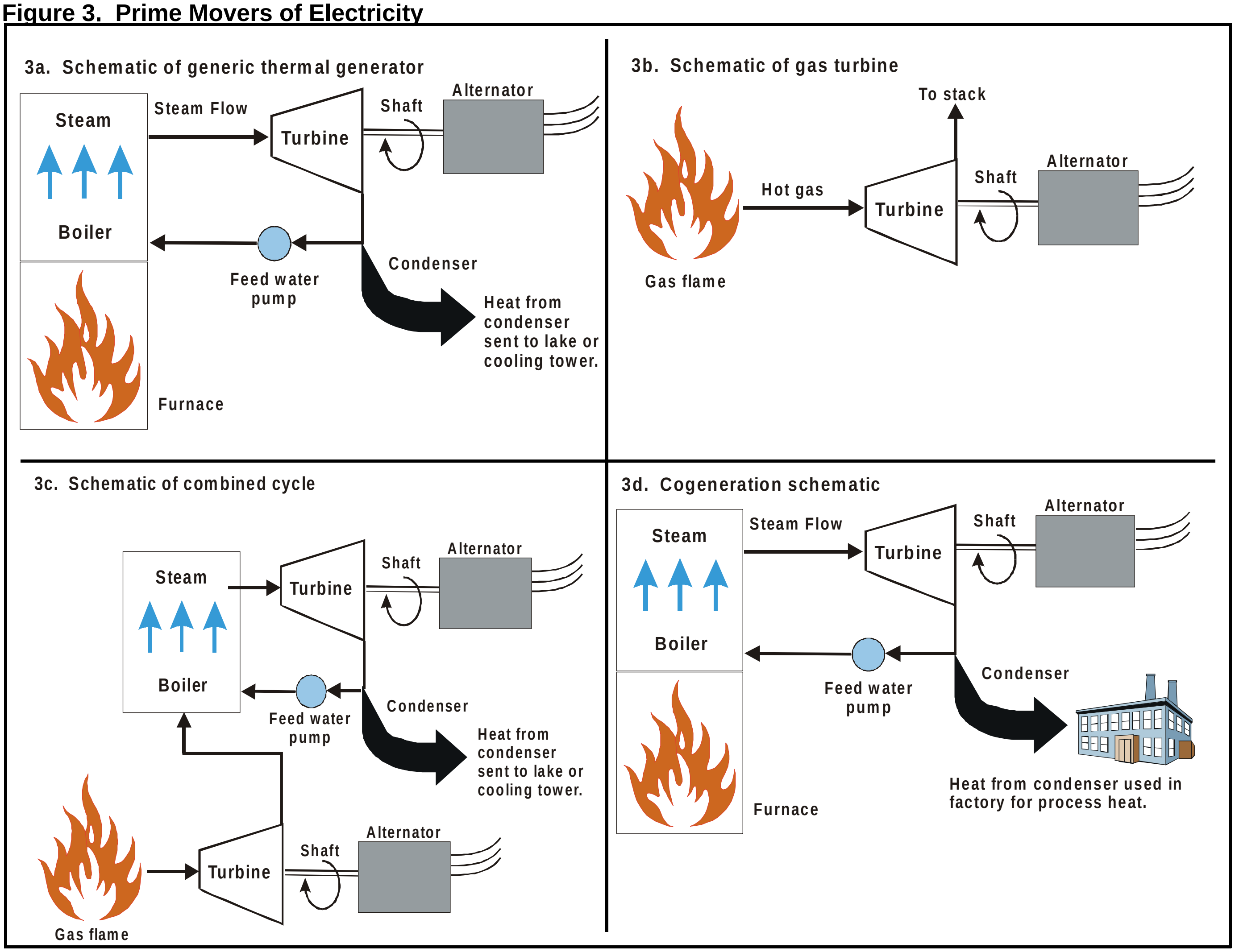
Gas and Petroleum: Gas and petroleum units, which are typically used for peak demand, make up 23 percent and 8 percent, respectively, of generating capability. In 1998, petroleum-fired generation provided 4 percent of our electricity, while gas-fired units provided 15 percent.

Coal, petroleum, and gas are considered fossil-fuels and collectively produced 71 percent of the Nation's electricity in 1998. When fossil fuels are burned in the production of electricity, a variety of gases and particulates are formed. If these gases and particulates are

[17] Thermal efficiency is a measure generally expressed in Btu per kilowatthour which is computed by dividing the total Btu content of the fuel burned for electric generation by the resulting net kilowatthour generation.

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

Figure 3. Prime Movers of Electricity



Source: R. Baldick, "Introduction to Electric Power Systems for Legal and Regulatory Professionals," Course Materials, The University of Texas at Austin (1999).

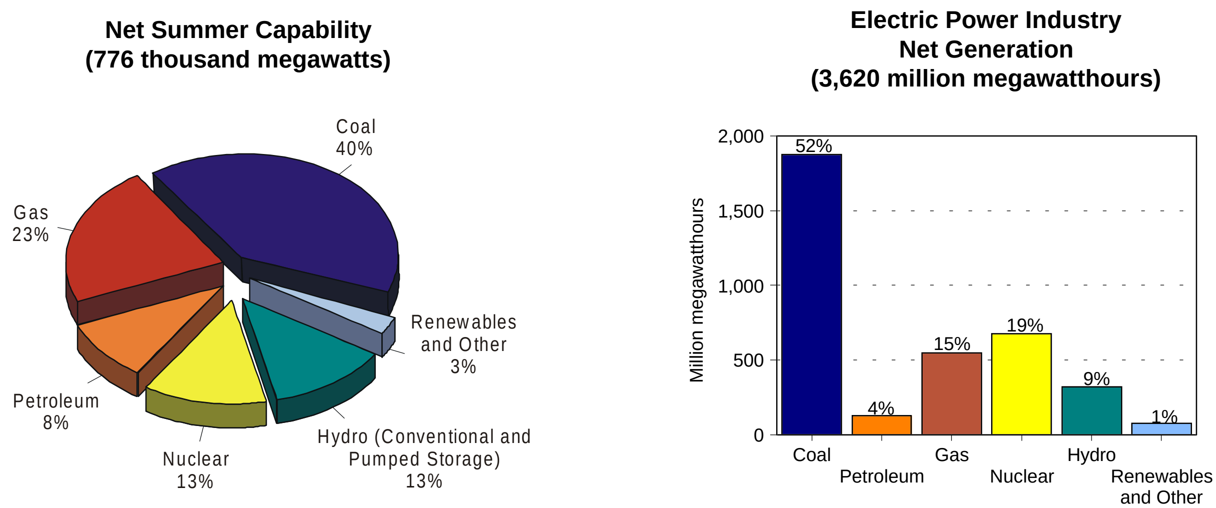
not captured by some pollution control equipment, they are released into the atmosphere. Among the gases emitted during the burning of fossil fuels are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). Coal-fired generating units produce more SO_2, NO_x, and CO_2 than other fossil-fuel units for two reasons. First, because coal generally contains more sulfur than other fossil fuels, it creates more SO_2 when burned. Second, there are more emissions from coal-fired plants because more coal-fired capacity than other fossil-fueled capacity is in use.

Nuclear: Nuclear power plants, which also are used as baseload plants, represented 13 percent of the generating capability, and generated 19 percent of electricity in 1998. Nuclear plants have increased their capacity factors (the ratio of electricity actually produced to potential production if the unit runs at full power) steadily in recent years, reaching a record high of 86 percent in 1999.

Hydroelectric: Hydroelectric capability[19] accounts for 13 percent of the Nation's generating capability. Precipitation patterns affect the availability of hydroelectric power, which contributed 9 percent of net generation in 1998, a relatively dry year.

[19] Hydroelectric power includes pumped storage which is the generation of electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Figure 4. Electric Power Industry Capability and Generation by Energy Source, 1998



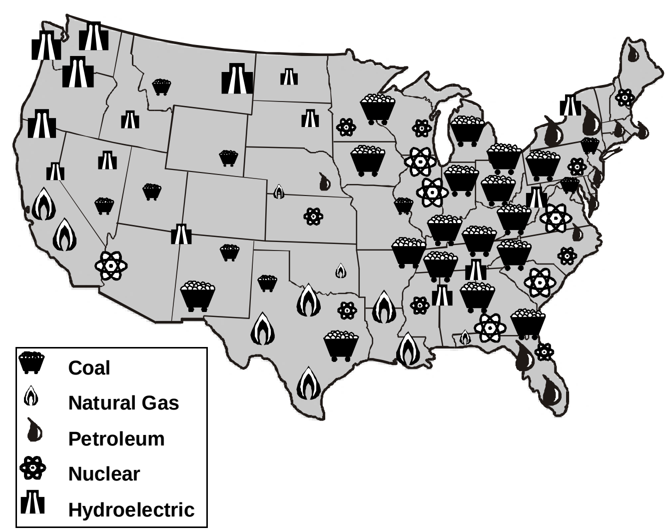
Source: **Capacity**: Form EIA-860A, “Annual Electric Generator Report-Utility” and Form EIA-860B, “Annual Electric Generator Report – Nonutility.” **Generation**: Form EIA-860B, “Annual Electric Generation Report – Nonutility” and Form EIA-759, “Monthly Power Plant Report.”

Renewables: Renewable generating units use energy sources that are judged to be inexhaustible including solar, wind, geothermal, municipal solid waste, and biomass fuels such as landfill methane gas, wood byproducts, and waste. (Hydroelectric power is also considered a renewable resource.) Many wind and solar plants are intermittent in nature, depending on the availability of their energy source. In 1998, renewables other than hydropower represented 3 percent of capacity and 1 percent of generation, as they are typically used only intermittently.

Regional Variation

The type of energy source used for generating electricity varies in the United States by region and is usually dictated by the availability of natural resources (Figure 5). The Pacific Northwest generates most of its power at large hydroelectric projects owned by the Federal Government. The Nation’s coal-producing States and regions are the location of the majority of coal-fired plants, and consequently the source of much of the air emissions resulting from the combustion of coal. Ohio, West Virginia, Kentucky, and Tennessee are the largest users of coal for electricity generation in the Nation. Texas, Louisiana, and Oklahoma are rich in natural gas, and make use of it for electricity generation. Much of the Nation’s petroleum-fired generation is concentrated in Florida and New York.

Figure 5. Energy Sources for Electricity Generation by Region



Note: The large icons on this map represent about 10 GW of capacity, not individual plants, in a regional area for each fuel source. Smaller icons represent about 5 GW capacity. Where less than 5 GW of capacity for a fuel type exists for an individual region or State, generating plants are not represented on this map.

Source: Form EIA-860A, “Annual Electric Generator Report – Utility” and Form EIA-860B, “Annual Electric Generator Report – Nonutility.”

California's tight restrictions on air emissions discourage coal-fired generation. Natural gas, which burns more cleanly than coal, is used by many California plants for electricity generation. However, California utilities purchase electricity from outside of the State, some of which is generated from coal as the main fuel source. The energy source available for electricity generation is a factor in the disparity of retail prices across the Nation. For example, the Northwest enjoys the low cost of hydropower, while some Northeast States depend heavily on petroleum and nuclear power.

Regulation of Generation

The foundation for strong Federal involvement in the electricity industry was established in the early 1900s. The electric power industry became recognized as a natural monopoly due to its production of a product most efficiently provided in a specific location by one supplier. Because monopolies in the United States were outlawed by the Sherman Antitrust Act, regulation of the utilities was a necessity. Interstate wholesale markets and transmission became regulated by the Federal Power Commission. In 1997, regulatory authority was given to the Federal Energy Regulatory Commission (FERC). Today, FERC has jurisdiction over interstate movement of electricity by private utilities (investor-owned utilities), power marketers, power pools, power exchanges, and independent system operators (ISOs). FERC approves rates for wholesale sales of electricity and reviews rates set by the Federal Power Marketing Administrations (PMAs). FERC also confers Exempt Wholesale Generator status (a classification of generator created by the Energy Policy Act of 1992 (EPACT)) and certifies qualifying small power producers and cogeneration facilities under provisions of PURPA. An additional responsibility of FERC is licensing the construction and operation of hydroelectric power projects and enforcing the provisions of the licenses.

The State Public Utility Commissions (PUCs) have jurisdiction over intrastate trade of electricity. The PUCs regulate retail rates for customers, approve sites for generation facilities, and issue State environmental regulations.

The Environmental Protection Agency (EPA) is charged with implementing the provisions of Title IV of the Clean Air Act. The EPA establishes rules requiring fossil-fueled power plants to reduce the air emissions and pollutants that are a primary cause of acid rain, sulfur dioxide, and nitrogen oxides. Carbon dioxide (CO_2) emissions are tracked, but no regulations exist at this time for CO_2 emissions.

The Nuclear Regulatory Commission licenses the construction and operation of nuclear power plants and fuel cycle facilities, inspects licensed nuclear facilities and oversees decommissioning, and enforces the provisions of nuclear licenses.

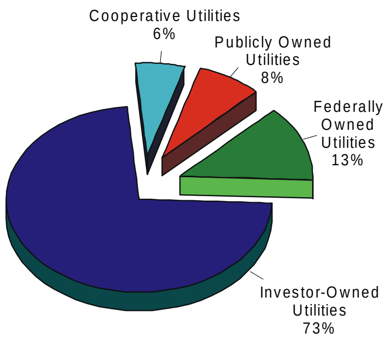
Transmission

Electric power transmission is the transportation of large blocks of power over relatively long distances from a central generating station to main substations close to major load centers or from one central station to another for load sharing. The transmission grid consists of high voltage (between 138 and 765 kilovolts) overhead and underground conducting lines made of either copper or aluminum. High-voltage transmission lines are used because they require less surface area for a given carrying power capacity, and result in less line loss. Because of resistance in the conductors, some power is "lost" as dissipated heat during transmission. At the generating station, the voltage of the three-phase alternating current output from the generator is increased to the required transmission voltage by a step-up transformer. The high-voltage alternating current is then transmitted through the transmission grid to the load center where it is again transformed (stepped down) to lower voltages required by distribution lines.

In the United States, investor-owned utilities (IOUs) own 73 percent of the transmission lines, Federally owned utilities own 13 percent, and public utilities and cooperative utilities own 14 percent (Figure 6).[20] Not all utilities own transmission lines (i.e., they are not vertically integrated), and no independent power producers or power marketers own transmission lines. Over the years, these transmission lines have evolved into three major networks (power grids), which also include smaller groupings or power pools. The major networks consist of extra-high-voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another. These transfers are restricted, on occasion, because of a lack of contractual arrangements or because of inadequate transmission capability. The three networks are the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect (Figure 7). The

[20] Refer to Table 2 for a definition of the types of utilities and other entities involved in electricity supply.

Figure 6. Transmission Ownership in the United States



Estimated High-Voltage Transmission Line Miles in the United States, 1994 (Miles)

Investor-Owned	199,924
Publicly Owned	21,960
Cooperative	16,005
Federally Owned	35,675
Total	**273,564**

Source: Calculations made by the Energy Information Administration, Office of Coal, Nuclear, Electric, and Alternate Fuels, from data taken from FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others." (Data for cooperative utilities are for 1997.)

The Texas Interconnect is not interconnected with the other two networks (except by certain direct current lines). The other two networks have limited interconnections to each other. Both the Western and the Texas Interconnect are linked with different parts of Mexico. The Eastern and Western Interconnects are completely integrated with most of Canada or have links to the Quebec Province power grid. Virtually all U.S. utilities are interconnected with at least one other utility by these three major grids. The exceptions are utilities in Alaska and Hawaii. The interconnected utilities within each power grid coordinate operations and buy and sell power among themselves.

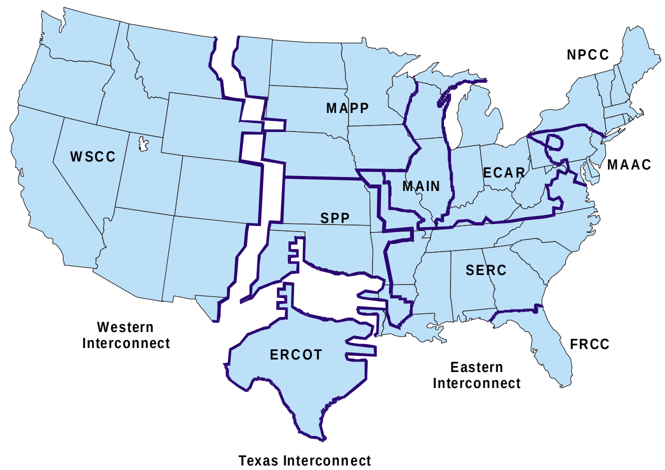
Regulation of Transmission

Under authority of the Federal Power Act of 1935, as amended, FERC exercises principal regulatory authority over the transmission system. Under this authority, FERC:

- regulates wholesale electricity rates and services for wholesale transactions
- approves sale or leasing of transmission facilities
- approves mergers and acquisitions between IOUs, and
- exercises jurisdiction over the interstate commerce of electricity.

FERC's authority covers about 73 percent of the power transmission system in the United States, while the remaining 27 percent is Federally owned, municipally owned, or owned by cooperative utilities, and is not under FERC's jurisdiction.

Figure 7. The Main Interconnections of the U.S. Electric Power Grid and the 10 North American Electric Reliability Council Regions



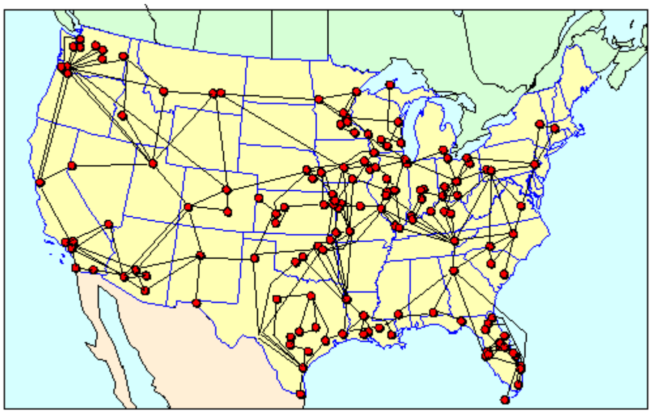
ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
MAAC - Mid-Atlantic Area Council
MAIN - Mid-America Interconnected Network
MAPP - Mid-Continent Area Power Pool
NPCC - Northeast Power Coordinating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

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

In 1965, a major blackout in the Northeastern United States precipitated the voluntary formation of the North American Electric Reliability Council (NERC). NERC is responsible for overall reliability, planning, and coordination of the electricity supply in North America. The membership of NERC is unique—as a not-for-profit corporation, NERC's owners comprise 10 Regional Councils (Figure 7). The members of these Regional Councils come from all segments of the electric industry–utilities, independent power producers, power marketers, and electricity customers. The councils cover the 48 contiguous States, part of Alaska, and portions of Canada and Mexico. The councils are responsible for overall coordination of bulk power policies that affect the reliability and adequacy of service in their areas. They also regularly exchange operating and planning information among their member utilities. However, participation in NERC is voluntary and participants in the industry are neither required to be a member nor to follow the directions of NERC. The boundaries of the NERC regions follow the service areas of the electric utilities in the region, many of which do not follow States boundaries.

Because electric energy is instantaneously generated and consumed, the operation of an electric power system requires a coordinated balancing of generation and consumption of power. Control Area Operators (CAOs) perform this function, as well as other important tasks, that allow the interconnected electric power systems and their components to operate together both reliably and efficiently. There are approximately 150 Control Areas in the Nation (Figure 8). Most are run by the dominant large investor-owned utility in a geographic area defined by an interconnected transmission grid and power plant system. The CAOs dispatch generators from a central control center with computerized systems in such a way as to balance supply and demand and maintain the transmission system safely and reliably.

Figure 8. Electric Control Area Operators – Continental United States, 1998



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Based on data contained in Form EIA-861, "Annual Electric Utility Report."

Distribution

Distribution is the delivery of electric power from the transmission system to the end-use consumer. The distribution systems begin at the substations, where power transmitted on high voltage transmission lines is transformed to lower voltages for delivery over low voltage lines to the consumer sites. The system ends at the consumers' meters. Distribution is considered a "natural monopoly" and is likely to remain a regulated function because duplicate systems of lines would be impractical and costly.[21]

Distributed generation is a growing part of the restructured electric power industry. Distributed generation is defined as small generators located near or at the consumer site, within the distribution system. Distributed generators are not directly connected to the transmission grid.[22] The amount of distributed generation is expected to increase in the future, with the technological and economic improvements in small generators. Fuel cells and photovoltaic systems are becoming more available as alternative or supplemental power sources.

Net metering arrangements are increasingly being offered in some States to consumers that install distributed generation units using renewable resources at their homes or businesses. The owners may use all or most of the power produced, but at times the distributed generator produces more power than the owner uses, and excess power flows out onto the distribution system. The consumer's meter "runs backwards," and "nets out" the portion of the electricity delivered to the consumer.

Regulation of Distribution and Retail Sales

The distribution of electric power is an intrastate function under the jurisdiction of State public utility commissions (PUCs). Under the traditional regulatory system, the PUCs set the retail rates for electricity, based on the cost of service, which includes the costs of distribution. Retail rates are set by the PUC in ratemaking rulings. The rates include the cost to the utility for generated and purchased power, the capital costs of power, transmission, and distribution plants, all operations and maintenance expenses, and the costs to provide programs often mandated by the PUC for consumer protections and energy efficiency, as well as taxes. As the industry restructures, in some States the PUC will eventually no longer regulate the retail rates for generated or purchased power. Retail electricity prices will be open to the market forces of competition. The PUCs will continue to regulate the rates for distribution of power to the consumer. They also have a say in the siting of distribution lines, substations, and generators. Metering and billing are under jurisdiction of the PUC and in some States are becoming competitive functions. As the industry restructures, the PUCs' responsibilities are changing. The goal of each State PUC

[21] Competition for the distribution of electricity is being evaluated in California.

[22] Distributed generators are indirectly connected to the grid through their consumers' facilities which are connected for backup purposes or to sell excess power.

remains to provide their State's consumers with reliable, reasonably and fairly priced electric power.

The Components of Electricity Supply – Utilities and Nonutilities

Introduction

This section provides a basic understanding of the infrastructure of the electric power industry, i.e., the components that carry out the generation, transmission, and distribution of electricity. The components consist of two broad categories of energy providers—utilities and nonutilities.[23] Their ownership characteristics, their current role in electricity supply, and how some roles have shifted since passage of the Energy Policy Act of 1992 (EPACT)[24] are explained in the following sections. In most cases, the data presented are for 1998, although in some cases, data for earlier years are compared with 1998 data to show changes.

Utilities

Electric utilities in general are defined as either privately owned companies or public agencies engaged in the generation, transmission, and / or distribution of electric power for public use. Utilities can be further classified into four subcategories based on ownership—investor-owned, Federally owned, other publicly owned, and cooperatively owned (Tables 2 and 3).

Under the traditional system, utilities are given a monopoly franchise over a specific geographic area. In return for this franchise, the electric utility is regulated by State and Federal agencies. Some electric utilities have service territories extending beyond a single county or parish. Others just serve a municipality or part of a county. Many counties in the United States are served by more than a single utility, and some parts of the country (such as Kossuth County, Iowa and Fillmore County, Minnesota) have more than 10 electric utilities operating in a county.

To move electricity among utilities, an extensive system of high-voltage transmission lines is owned and operated by the Nation's larger utilities. This transmission network permits electricity trading between utilities. Without transmission facilities, electricity could not be moved from power plants to the thousands of distribution systems serving millions of consumers of electric power.

Utilities can also be categorized in a different manner, i.e., the number of companies that generate, transmit, and / or distribute electric power. It is interesting to note that only about 27 percent of the Nation's 3,169 utilities actually generate electric power. Many electric utilities (67 percent) are exclusively distribution utilities, purchasing wholesale power from others to distribute it, over their own distribution lines, to the ultimate consumer. These are primarily the utilities owned by State and local governments and cooperatives. Conversely, all nonutilities generate power but do not own or operate transmission or distribution systems (Table 4).

Investor-Owned Utilities

Two basic organizational forms exist among investor-owned utilities (IOUs). The most prevalent is the individual corporation. Another common form is the holding company, in which a parent company is established to own one or more operating utility companies that are integrated with one another.

Most of the IOUs sell power at retail rates to several different classes of consumers and at wholesale rates to other utilities, including other investor-owned, Federal, State, and local government utilities, public utility districts, and rural electric cooperatives (Figure 9). They also have high-density service areas.

Federal Utilities

There are nine Federal electric utilities in the United States (Figure 10). They include four operating entities: the Department of Defense's U.S. Army Corps of Engineers (USACE), the Department of the Interior's U.S. Bureau of Reclamation, the Department of the Interior's U.S. Bureau of Indian Affairs (USBR), and the Department of State's International Water and Boundary Commission. These entities operate the Federal hydroelectric plants.

Also included in this category are four Federal power marketing administrations (PMAs): the Bonneville

[23] Nonutilities generate but do not transmit or distribute electricity.

[24] As earlier stated, EPACT provided a Federal mandate to open up the national electricity transmission system to wholesale suppliers, marking the beginning of competition in the electric power industry, and was the impetus for significant structural changes. In 1996, the Federal Energy Regulatory Commission (FERC) issued its Order 888, which carried out the goal of EPACT. From the 1970s until 1992, little change had occurred in the industry, either structurally or operationally, with the exception of the creation of nonutility qualifying facilities brought about by PURPA.

Table 2. Major Characteristics of U.S. Electric Utilities by Type of Ownership, 1998

Ownership	Major Characteristics
Investor-Owned Utilities (IOUs) IOUs account for about three-quarters of all utility generation and capacity. There are 239 IOUs in the United States, and they operate in all States except Nebraska. They are also referred to as privately owned utilities.	• Earn a return for investors; either distribute their profits to stockholders as dividends or reinvest the profits. • Are granted service monopolies in specified geographic areas. • Have obligation to serve and to provide reliable electric power. • Are regulated by State and Federal governments, which in turn approve rates that allow a fair rate of return on investment. • Most are operating companies that provide basic services for generation, transmission, and distribution.
Federally Owned Utilities There are 9 Federally owned utilities in the United States, and they operate in all areas except the Northeast, the upper Midwest, and Hawaii.	• Power not generated for profit. • Publicly owned utilities, cooperatives, and other nonprofit entities are given preference in purchasing from them. • Primarily producers and wholesalers. • Producing agencies for some are the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the International Water and Boundary Commission. • Electricity generated by these agencies is marketed by Federal power marketing administrations in the U.S. Department of Energy . • The Tennessee Valley Authority is the largest producer of electricity in this category and markets at both wholesale and retail levels.
Other Publicly Owned Utilities Other publicly owned utilities include: Municipals Public Power Districts State Authorities Irrigation Districts Other State Organizations There are 2,009 in the United States.	• Are nonprofit State and local government agencies. • Serve at cost; return excess funds to the consumers in the form of community contributions and reduced rates. • Most municipals just distribute power, although some large ones produce and transmit electricity; they are financed from municipal treasuries and revenue bonds. • Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California; voters in a public power district elect commissioners or directors to govern the district independent of any municipal government. • Irrigation districts may have still other forms of organization (e.g., in the Salt River Project Agricultural Improvement and Power District in Arizona, votes for the Board of Directors are apportioned according to the size of landholdings). • State authorities, such as the New York Power Authority and the South Carolina Public Service Authority, are agents of their respective State governments.
Cooperatively Owned Utilities There are 912 cooperatively owned utilities in the United States, and they operate in all States except Connecticut, Hawaii, Rhode Island, and the District of Columbia.	• Owned by members (rural farmers and communities). • Provide service mostly to members. • Incorporated under State law and directed by an elected board of directors which, in turn, selects a manager. • The Rural Utilities Service (formerly the Rural Electrification Administration) in the U.S. Department of Agriculture was established under the Rural Electrification Act of 1936 with the purpose of extending credit to co-ops to provide electric service to small rural communities (usually fewer than 1,500 consumers) and farms where it was relatively expensive to provide service.
Power Marketers There are 194 active power marketers in the United States.	• Some are utility-affiliated while others are independent. • Buy and sell electricity. • Do not own or operate generation, transmission, or distribution facilities.

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

Table 3. Number of Electric Utilities by Class of Ownership and NERC Region, 1998

NERC Region[a]	Investor-Owned	Federal	State, Municipal, and Other Government	Cooperative	Total
ECAR	43	0	228	103	374
ERCOT	6	0	66	58	130
FRCC	3	0	31	12	46
MAAC	18	0	49	19	86
MAIN	17	0	131	33	181
MAPP	14	0	486	171	671
NPCC	58	0	127	10	195
SERC	20	2	352	262	636
SPP	11	0	250	86	347
WSCC	27	7	253	137	424
Subtotal NERC	**217**	**9**	**1973**	**891**	**3090**
Alaska[b]	19	0	36	21	76
Hawaii[b]	3	0	0	0	3
U.S. Total	**239**	**9**	**2,009**	**912**	**3,169**

[a]NERC is the North American Electric Reliability Council, formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America.

[b]Alaska and Hawaii are not full members of NERC.

Note: See Figure 7 for a map of NERC regions.

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

Power Administration, the Western Area Power Administration, the Southwestern Power Administration, and the Southeastern Power Administration (Figure 10). These Federal utilities exist to market and sell the power produced at Federal hydroelectric projects. They also purchase energy for resale from other electric utilities in the United States and Canada.

The ninth Federal utility is the Tennessee Valley Authority (TVA), the largest Federal power producer, which operates its own power plants and sells the power in the Tennessee Valley region in both the wholesale and retail markets. The TVA generates electricity from coal, gas, oil, and nuclear power as well as hydropower.

Of the Federal utilities, three are considered major producers of electricity: the TVA, the USACE, and the USBR. Generation by the USACE, except for the North Central Division (Saint Mary's Falls at Sault Ste. Marie, Michigan) and by the USBR, is marketed by the four PMAs.

Consumers of Federal power are usually large industrial consumers or Federal installations. Most of the remaining energy generated by non-profit Federal utilities is sold in the wholesale market to publicly owned utilities and rural cooperatives for resale at cost. These wholesale consumers have preference claims to Federal electricity. Only the surplus remaining after meeting the energy requirements of preference consumers is sold to investor-owned utilities.

Other Publicly Owned Utilities

Publicly owned electric utilities can be categorized as generators and nongenerators. (In contrast, virtually all investor-owned electric utilities own and operate generating capacity.) Generators are those electric utilities that own and operate generating capacity to supply some or all of their customers' needs. However, some generators supplement their production by purchasing power. The nongenerators rely exclusively on power purchases. Their primary function is to distribute electricity to their consumers. The nongenerators comprise over half of the total number of publicly owned electric utilities.

Other publicly owned utilities include municipal authorities, State authorities, public power districts, irrigation districts, and other State organizations. Municipal utilities tend to be concentrated in cities where the loads are small. They exist in every State except Hawaii, but most are located in the Midwest and Southeast. State authorities are utilities that function in a manner similar to Federal utilities. They generate or purchase electricity

Table 4. Energy Supply Participants and Their Operations, 1998

Participants/Operations	Number of Companies	Percent of All Utilities
Vertically Integrated (Generate,[a] Transmit,[b] and Distribute[c])		
Utilities Only		
Investor Owned	140	4.4
Federal	3	0.1
Publicly Owned	132	4.2
Cooperatives	20	0.6
Total	295	9.3
Generate and Transmit Only		
Utilities Only		
Investor Owned	10	0.3
Federal	3	0.1
Publicly Owned	36	1.1
Cooperatives	40	1.3
Total	89	2.8
Transmit and Distribute Only		
Utilities Only		
Investor Owned	6	0.2
Federal	1	0.0
Publicly Owned	58	1.8
Cooperatives	74	2.3
Total	139	4.4
Generate and Distribute Only		
Utilities Only		
Investor Owned	25	0.8
Federal	2	0.1
Publicly Owned	403	12.7
Cooperatives	23	0.7
Total	453	14.3
Generate Only		
Utilities		
Investor Owned	11	0.3
Federal	0	--
Publicly Owned	12	0.4
Cooperatives	1	0.0
Total	24	0.8
Nonutilities	1,930	[d]100.0
Transmit Only		
Utilities Only		
Investor Owned	7	0.2
Federal	0	--
Publicly Owned	8	0.3
Cooperatives	19	0.6
Total	34	1.1

See notes at end of table.

Table 4. Energy Supply Participants and Their Operations, 1998 (Continued)

Participants/Operations	Number of Companies	Percent of All Utilities
Distribute Only		
Utilities Only		
Investor Owned	34	1.1
Federal	1	0.0
Publicly Owned	1,358	42.8
Cooperatives	735	23.2
Total	2,128	67.1
Other[e]		
Utilities Only		
Investor Owned	6	0.2
Publicly Owned	2	0.1
Total	8	0.2
Power Marketers[f]	[g]400	--

[a]An electricity generator is a facility that converts mechanical energy into electrical energy.

[b]An electricity transmitter moves or transfers electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

[c]An electricity distributor delivers electric energy to an end user.

[d]This figure represents the percentage of nonutilities rather than utilities.

[e]"Other" includes maintenance service companies for parent utilities that perform such functions as guard services, equipment maintenance, etc. Also, one of the publicly owned utilities in this category acts as an agent to buy and schedule power for the parent utility.

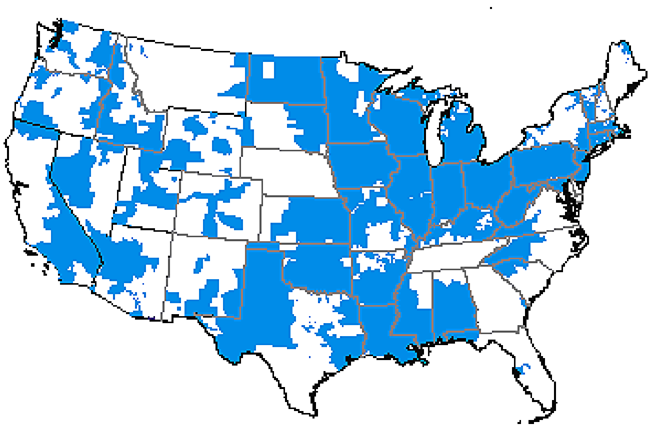
[f]An electricity power marketer buys and sells electricity but does not own or operate generation, transmission, or distribution facilities.

[g]In 1998, about 400 power marketers filed rate tariffs with FERC, of which 111 reported wholesale sales and 49 reported retail sales. Currently, over 850 power marketers have filed rate tariffs with FERC.

-- = Not applicable.

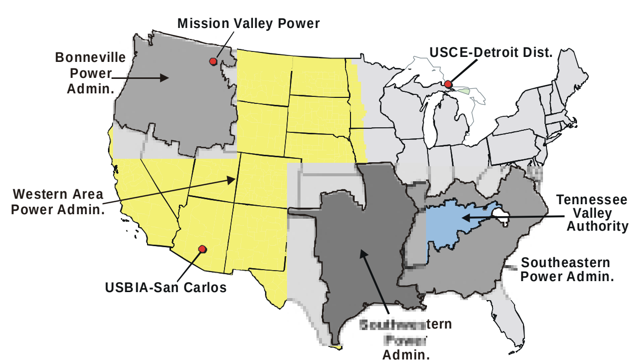
Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-860B, "Annual Electric Generator Report – Nonutility."

Figure 9. Service Areas of Investor-Owned Utilities, 1998



Source: Resource Data International, 1998.

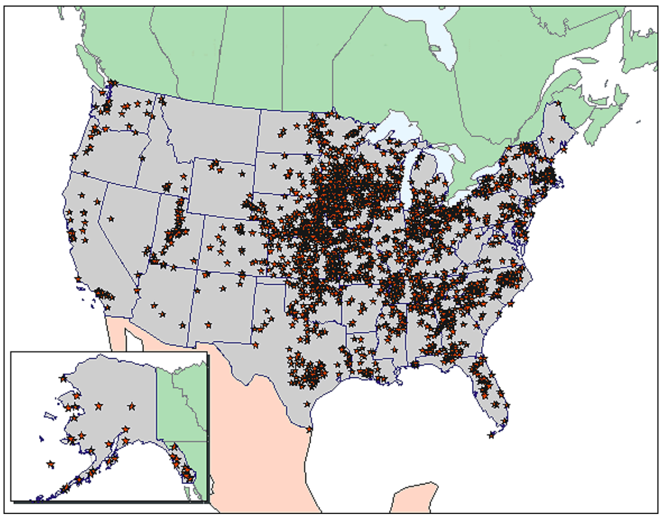
Figure 10. Service Areas of Federal Utilities, 1998



Source: EIA, Office of Coal, Nuclear, Electric and Alternate Fuels. Based on data contained in Form EIA-412, "Annual Report of Public Electric Utilities."

from other utilities and market large quantities in the wholesale market to groups of utilities within their States at lower prices than the individual utilities would otherwise pay. Large concentrations of publicly owned power districts are in the Midwest and Eastern regions of the United States (Figure 11). In general, publicly owned utilities tend to have lower costs than investor-owned utilities because they often have access to tax-free financing and do not pay certain taxes or dividends. They also tend to have high-density service areas.

Figure 11. Publicly Owned Utilities in the United States, 1998



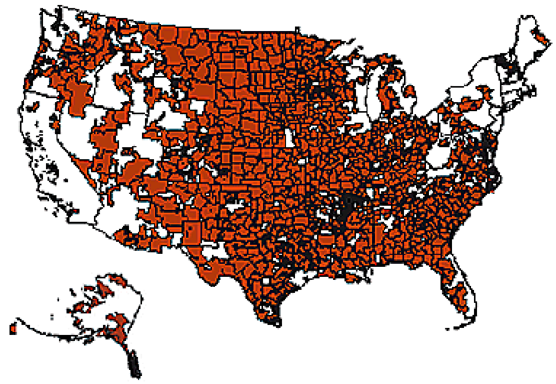
Source: EIA, Office of Coal, Nuclear, Electric and Alternative Fuels. Based on data contained in Form EIA-412, "Annual Report of Public Electric Utilities."

Rural Electric Cooperatives

Most rural electric cooperative utilities are formed and owned by groups of residents in rural areas to supply power to those areas (Figure 12). Some cooperatives may be owned by a number of other cooperatives. There are really three types of cooperatives: (1) distribution only, (2) distribution with power supply, and (3) generation and transmission. Cooperatives currently operate in 47 States, and they represent 29 percent of the total number of utilities in the country. Most distribution cooperatives resemble municipal utilities in that they often do not generate electricity, but purchase it from other utilities.

The other type (generating and transmission cooperatives) are usually referred to as "power supply cooperatives." These cooperatives are usually owned by the distribution cooperatives to whom they supply wholesale power. Distribution cooperatives resemble Federal utilities, supplying electricity to other utility consumers from their generating capability.

Figure 12. Service Areas of Cooperative Utilities, 1998



Source: National Rural Electric Cooperative Association's website at http://www.nreca.org (1998).

Non-Federal Power Marketers

The introduction of the competitive wholesale market for electricity has brought about a fifth subcategory of electric utilities—power marketers. They are classified as electric utilities because they buy and sell electricity at the wholesale and retail levels. However, they do not own or operate generation, transmission, or distribution facilities, and therefore, their data (primarily electricity purchase and sales data) are not included in this chapter. Although relatively small in terms of volume of sales, the power marketers are a growing segment of the industry. Currently, over 850 power marketers have filed rate tariffs with FERC to sell electric power, but only approximately 160 were actively engaged in retail and / or wholesale sales during 1998.[25]

Nonutilities

Nonutilities are privately owned entities that generate power for their own use and / or for sale to utilities and others. Nonutilities can be classified in two distinct ways. One approach separates nonutilities into separate categories based on their classification by FERC and the type of technology they employ: (1) cogenerators and (2) small power producers, both of which are qualifying facilities (QFs) because they meet certain criteria set

[25] Form EIA-861, "Annual Electric Utility Report," 1998.

forth by PURPA;[26] (3) exempt wholesale generators mandated by EPACT and designated by FERC, (4) cogenerators not qualified under PURPA, and (5) noncogenerators not qualified under PURPA (Table 5). As the industry furthers its transition to full retail competition in the generation portion of electricity supply, the distinctions between the nonutility subcategories are becoming less clear, and some may fade entirely within the next 10 years as a result of ongoing structural changes and the possible repeal of the Federal mandates that created them.

A second approach for classifying nonutilities is based on the major industry group into which the nonutility company falls. Nonutility electricity generators are found in many different industries. In 1998, most nonutility generating capacity (52 percent) was in the manufacturing sector of the economy (Figure 13). Within the manufacturing sector, the chemical industry, the paper industry, and the petroleum refining industry account for 70 percent of the electricity generated by that sector. The manufacturing processes conducted at many of these plants can utilize the thermal energy produced when cogenerating electricity. After manufacturing, the largest portion of nonutility electricity generating capacity (23 percent) can be found in the electric, gas, and sanitary services sector. The entities that make up this sector are primarily engaged in producing, transporting,

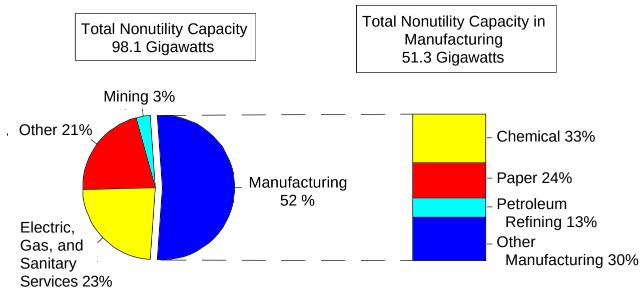
Table 5. Major Characteristics of U.S. Nonutilities by Type

Type	Major Characteristics
Cogenerators (QF) (Combined Heat and Power)	• Are qualified under PURPA by meeting certain ownership, operating, and efficiency criteria established by FERC. • Sequentially produce electric energy and another form of energy, such as heat or steam, using the same fuel source. • Are guaranteed that utilities will purchase their output at a price based on the utility's “avoided cost” and will provide backup service at nondiscriminatory rates.
Small Power Producers (QF)	• Are qualified under PURPA by meeting certain ownership, operating, and efficiency criteria, established by FERC. • Use biomass, waste, renewable resources (water, wind, solar), or geothermal as a primary energy source. • Fossil fuels can be used but renewable resources must provide at least 75 percent of the total energy input. • Are guaranteed that utilities will purchase their output at a price based on the utility's “avoided cost” and will provide backup service at nondiscriminatory rates.
Exempt Wholesale Generators	• Creation authorized by EPACT. • Are exempt from PUHCA's corporate and geographic restrictions. • Are wholesale producers; do not sell retail. • Do not possess significant transmission facilities. • Utilities are not required to purchase their electricity. • Are regulated but usually may charge market-based rates.
Cogenerators (Non-QF)	• Are not qualified under the provisions of PURPA. • Are nonutilities, utilizing a cogenerating technology, which may themselves consume part of the electricity they cogenerate.
Noncogenerators (Non-QF)	• Are not qualified under the provisions of PURPA. • Do not utilize a cogenerating technology.

QF = Qualifying facility (under PURPA).
Note: An entity can be any combination of cogenerator QF, small power producer QF, and exempt wholesale generator.
Source: Energy Information Administration, *Electric Power Annual 1995,* Volume II, DOE/EIA-0348(95)/2 (Washington, DC, December 1996).

[26] QFs receive certain benefits under PURPA. In particular, they are guaranteed that electric utilities will purchase their output at a price based on the utility's “avoided cost.”

Figure 13. Shares of Nonutility Nameplate Capacity by Major Industry Group, 1998



Note: Totals may not equal the sum of components due to independent rounding.

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

and/or distributing electricity, although they may be engaged in steam, gas, water, and/or waste disposal services as a primary business. Unlike nonutilities in other sectors, these nonutilities are engaged primarily in activities similar to the generation activities carried out by electric utilities. The remaining nonutility capacity is found either in the mining industry (3 percent) or in various other industries, including agriculture, transportation, and other services (21 percent).

A Comparison of Utility and Nonutility Roles

The relative contribution of utility and nonutility components to the supply of the Nation's electricity can be understood by looking at their shares of nameplate capacity,[27] net generation,[28] additions to capacity, and number of companies (Figure 14). The number of publicly owned utilities (i.e., those owned by State and local governments) far outweighs the number of IOUs (2,009 versus 239); however, in 1998 IOUs were responsible for the lion's share of capacity (66 percent) and generation (68 percent). On the other hand, the nonutility share of capacity and generation has been relatively small, but that trend is changing. The change began with the passage of PURPA when nonutilities were promoted as energy-efficient, environment-friendly alternative sources of electricity. More recently, FERC Order 888 opened the bulk power transmission grid to suppliers other than utilities. In response, nonutilities have been expanding their roles in wholesale power supply and are taking advantage of the divestiture activities of utilities by purchasing their generation assets. As a result, the nonutility share of total industry capacity rose from 7 percent in 1992 to 12 percent in 1998.[29]

A yearly comparison of the above-mentioned four statistics (Figure 15) gives a clear picture of the significant shifts in ownership of electricity supply that have taken place in the relatively short period of time since passage of EPACT. A number of these shifts can be attributed to the strategic business plans companies are using to cope in a deregulated and competitive market. For instance, since 1992, the number of IOUs has decreased by 8 percent and their nameplate capacity has decreased by 5 percent (Figure 16). The decrease in the number of IOUs is a result of recent mergers between IOUs. The decrease in generation capacity is evidence of the divestiture of generation assets. On the other hand, the fact that IOU net generation has actually increased by 11 percent since 1992 can be attributed to such factors as higher demand for electricity and efficiency gains stemming from competition and mergers.

Although the number of nonutility companies decreased in 1997, the number of nonutilities grew by 9 percent during the 7-year period examined. Also, with nonutilities expanding by buying IOU generation assets and constructing new generation units, the result was an increase in nonutility nameplate capacity (up 73 percent since 1992) and generation (up 42 percent since 1992). Nonutility additions to capacity have been increasing at an average annual rate of nearly 7 percent since 1992.

Electricity Sales and Trade

Wholesale Sales and Trade

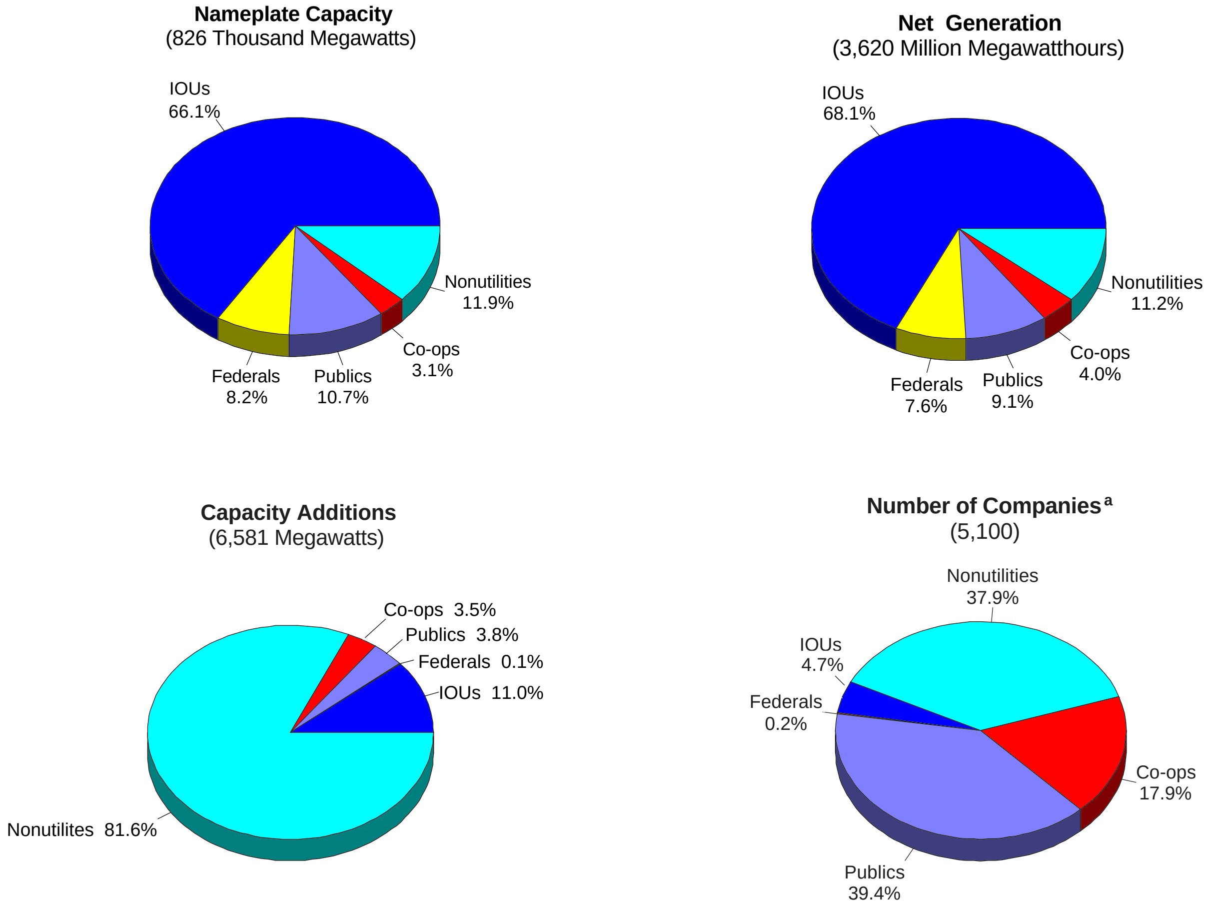
The bulk power system outlined earlier makes it possible for utilities to engage in wholesale (for resale) electric power trade. Wholesale trade has historically played an important role, allowing utilities to reduce power costs, increase power supply options, and improve reliability. In quantity, it accounts for more than one-half of electricity sales to ultimate consumers. Since 1986, the total amount of wholesale power trade (as measured by purchased power plus exchange received) among utilities and nonutilities has grown at an average annual rate

[27] EIA defines nameplate capacity as the maximum design production capacity specified by the manufacturer of a processing unit or the maximum amount of a product that can be produced running the manufacturing unit at full capacity.

[28] EIA defines net generation as gross generation minus plant use from all electric utility-owned plants.

[29] Energy Information Administration, *Electric Power Annual 1998, Volume I,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999), p. 1.

Figure 14. Share of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-860A, "Annual Electric Generator Report – Utility," Form EIA-861, "Annual Electric Utility Report," and Form EIA-860B, "Annual Electric Generator Report – Nonutility."

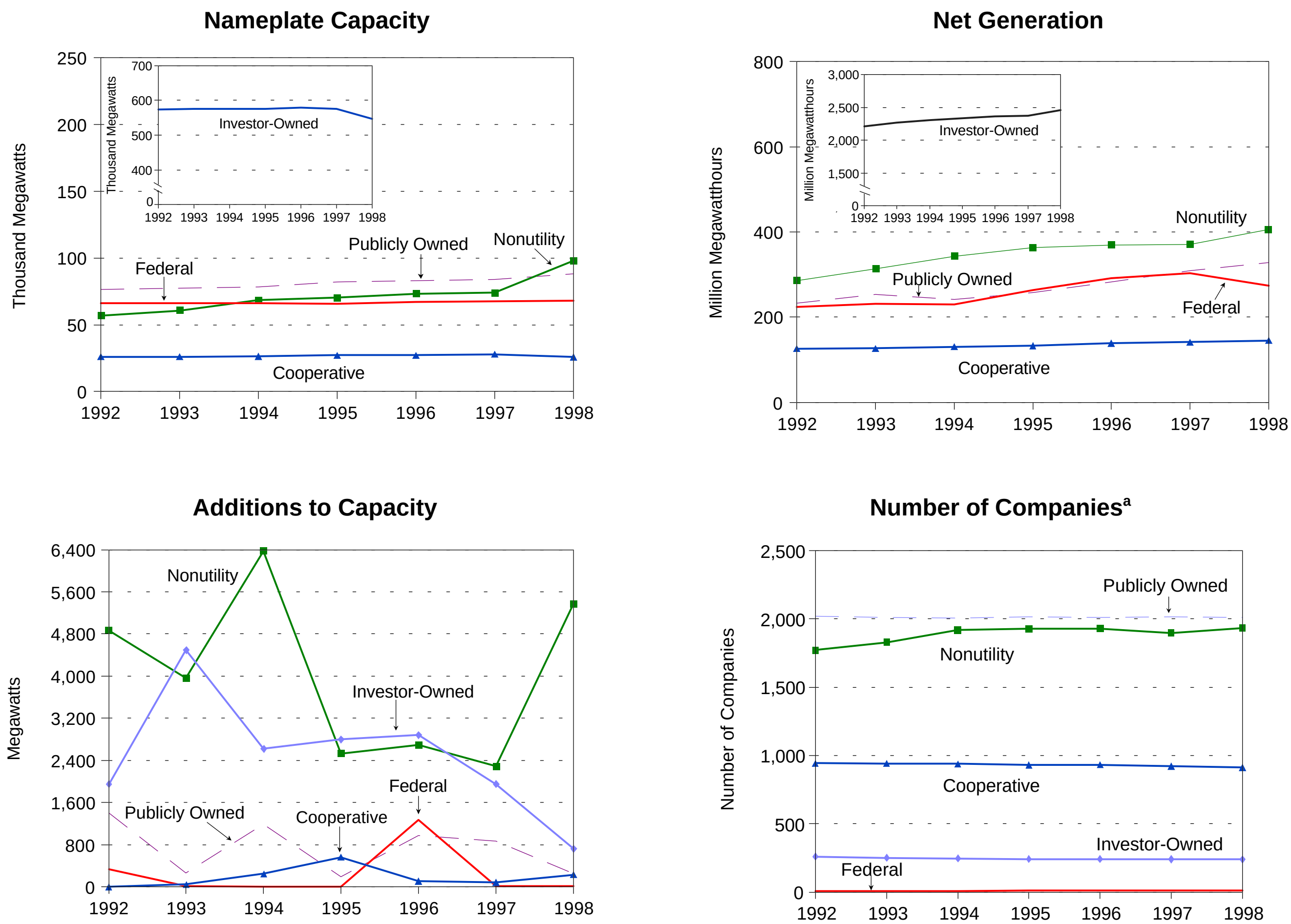
of 4.7 percent, which is more than the rate of growth for retail sales by utilities (3.1 percent). In the past, wholesale trade has been dominated by utility purchases from other utilities. In 1998, utilities purchased a total of 1,669 billion kilowatthours of wholesale electricity from other utilities and a smaller but increasing amount (259 billion kilowatthours) from nonutility producers (Figure 17).

Wholesale power sales by nonutilities to utilities and wheeling (the transmission of power from one point to another via a third party) by utilities have both grown vigorously. Wholesale sales by nonutilities grew from 40 billion to 259 billion kilowatthours between 1986 and 1998, yielding an average annual growth rate of 16.8 percent. Wheeling, while not increasing as spectacularly, grew at an annual average rate of 8.3 percent over the same period. Utility sales to ultimate consumers, wholesale sales by nonutilities, and wheeling by utilities all grew more slowly between 1990 and 1998, with annual growth rates of 2.2 percent, 12.6 percent, and 4.3 percent, respectively.

International Trade

In recent years, U.S. international trade in electricity has returned to the levels of the mid-1980s (Figure 18). U.S. trade is mostly in imports, which were more than three times the level of exports in 1998. Most imports are from Canada (99 percent of total gross imports in 1998) and the remainder is from Mexico.

Figure 15. Total Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1992-1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-860, "Annual Electric Generator Report," Form EIA-860A, "Annual Electric Generator Report – Utility," Form EIA-861, "Annual Electric Utility Report," Form EIA 867, "Annual Nonutility Power Producer Report," and Form EIA-860B, "Annual Electric Generator Report – Nonutility."

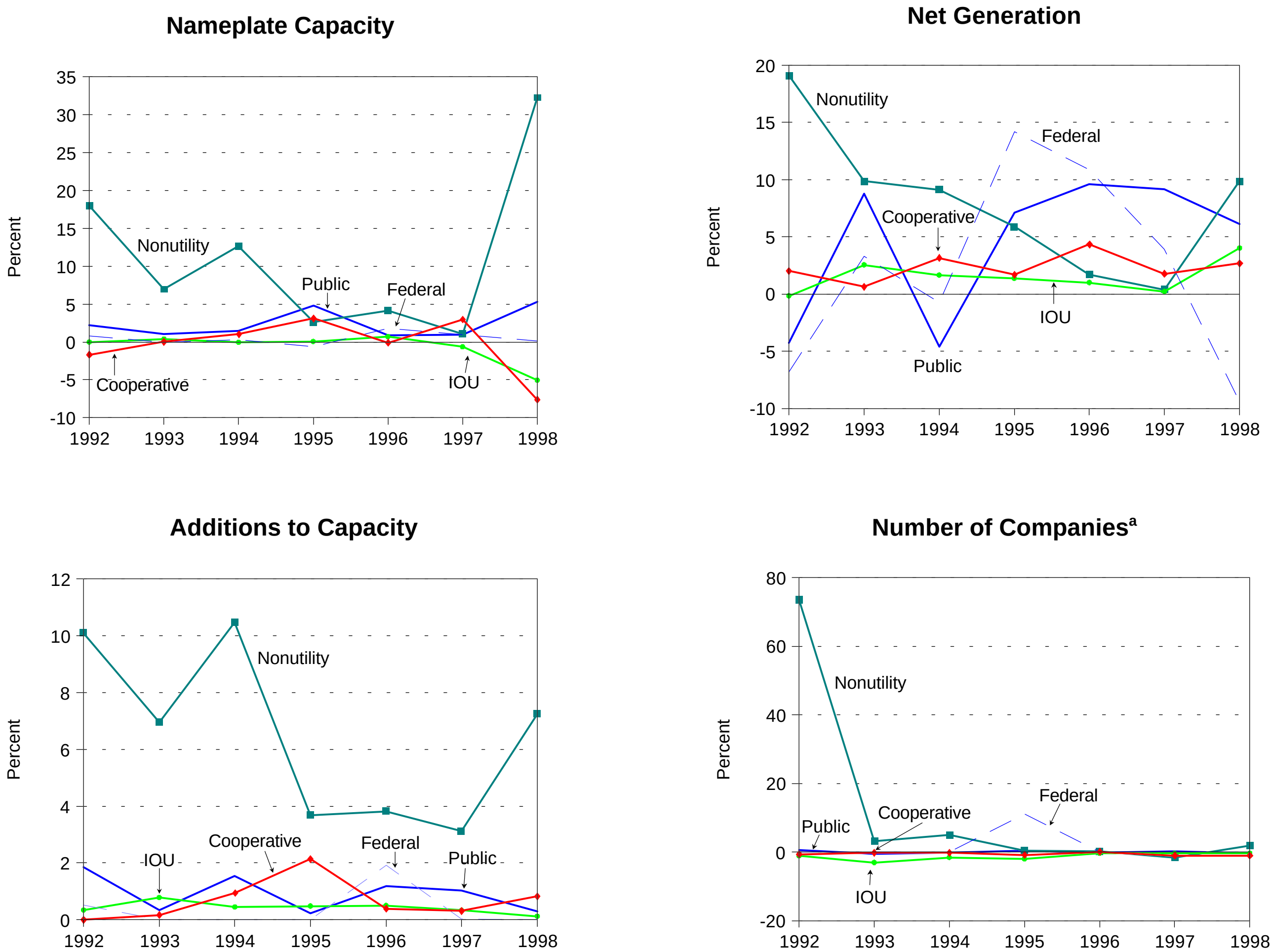
Imported power is particularly important to the NPCC and MAPP regions of NERC,[30] where gross imports were 7.2 and 6.5 percent, respectively, of retail sales by utilities in these regions in 1998. In contrast, gross imports for the Nation as a whole that year were 1.2 percent of retail sales by utilities.

Retail Sales by Sector

Electricity is sold to four classes or sectors of retail (i.e., ultimate) consumers—residential, commercial, industrial, and "other." The residential sector includes private households and apartment buildings where energy is consumed primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying appliances. The commercial sector includes nonmanufacturing business establishments such as hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The industrial sector includes manufacturing, construction, mining, agriculture, fishing, and forestry establishments. The "other" sector includes public street and highway

[30] Refer to Figure 7 for details on NERC regions.

Figure 16. Annual Growth Rate of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Companies, 1992-1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-860, "Annual Electric Generator Report," Form EIA-860A, "Annual Electric Generator Report – Utility," Form EIA-861, "Annual Electric Utility Report," Form EIA 867, "Annual Nonutility Power Producer Report," and Form EIA-860B, "Annual Electric Generator Report – Nonutility."

lighting, railroads and railways, municipalities, divisions or agencies of State and Federal Governments under special contracts or agreements, and other utility departments.[31]

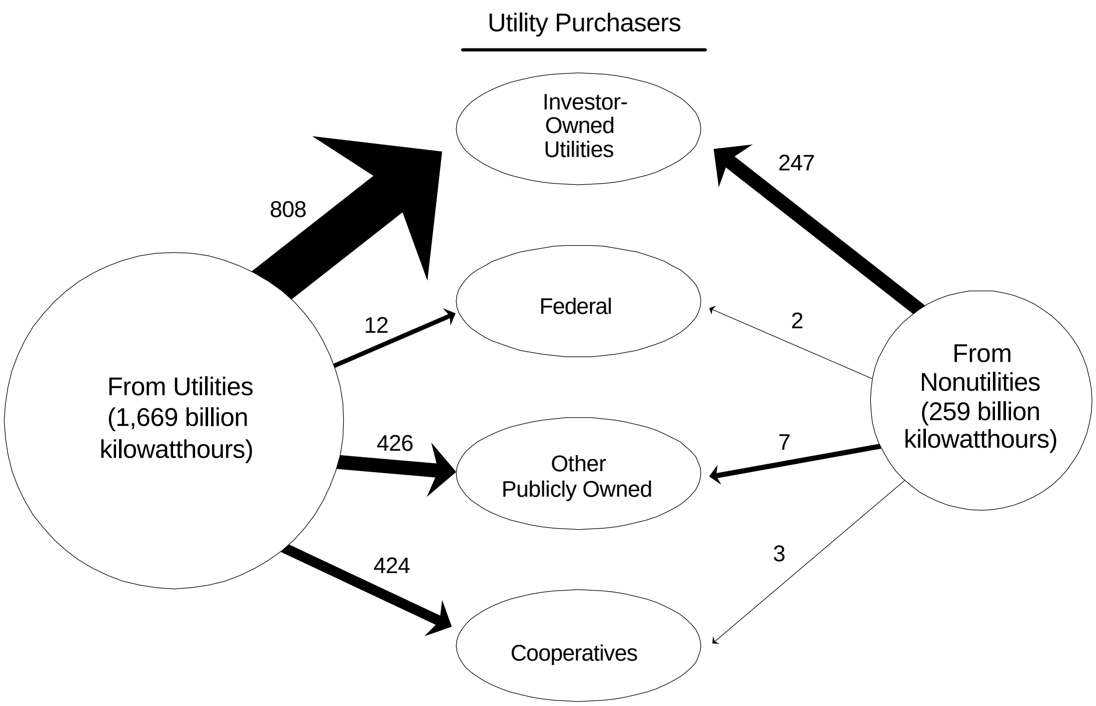
Sales to the residential sector in 1998 increased 20.1 percent from the 1992 level, to 1,128 billion kilowatthours, which represented 35 percent of sales to ultimate consumers. The 1998 commercial sector retail sales increased 25 percent and the industrial sector 8 percent from the 1992 levels. Together, these two non-residential sectors accounted for 62 percent of 1998 retail sales. Sales to the "other" sector were 104 billion kilowatthours in 1998, an increase of 25 percent over 1992 levels (Figures 19 and 20).

Retail Sales by Ownership Category

Sales by investor-owned electric utilities in 1998 increased 15.6 percent over 1992 levels and represented

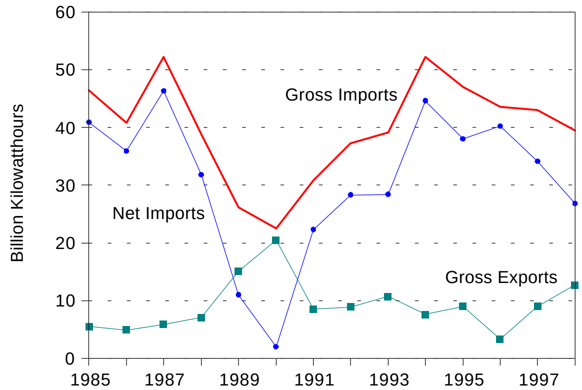
[31] There are some exceptions to the types of customers listed in each of the four sectors. For instance, some small manufacturers are classified as commercial while some large commercial establishments are classified as industrial.

Figure 17. Electric Utility Wholesale Power Purchases by Ownership Type, 1998
(Billion Kilowatthours)



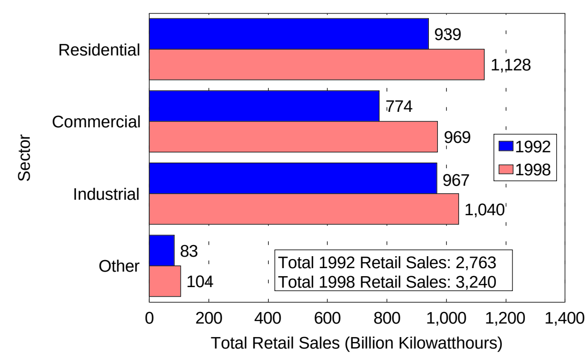
Notes: Data do not include utility purchases from power marketers. Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 18. U.S. International Electricity Trade, 1985-1998



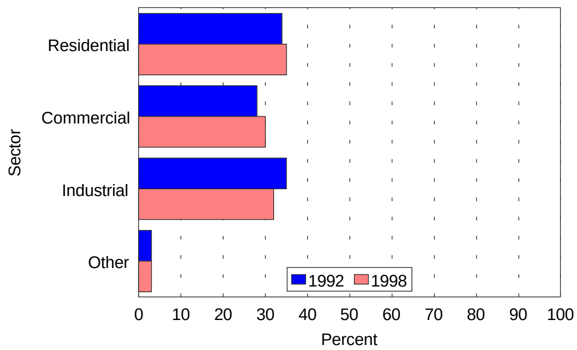
Source: **1985-1994:** Energy Information Administration, *Annual Energy Review 1995,* DOE/EIA-0384(95) (Washington, DC, July 1996), Table 8.1. **1995-1998:** Energy Information Administration, *Electric Power Annual 1998,* Volume II, DOE/EIA-0348(98)/2 (Washington, DC, December 1999), Tables 41-43.

Figure 19. Sales to Ultimate Consumers by Sector, 1992 and 1998



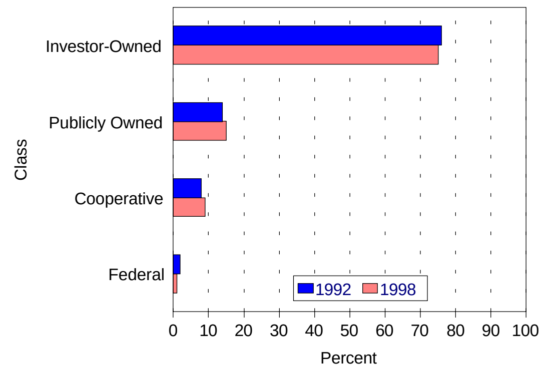
Notes: Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual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

Figure 20. Share of Sales to Ultimate Consumers by Sector, 1992 and 1998



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

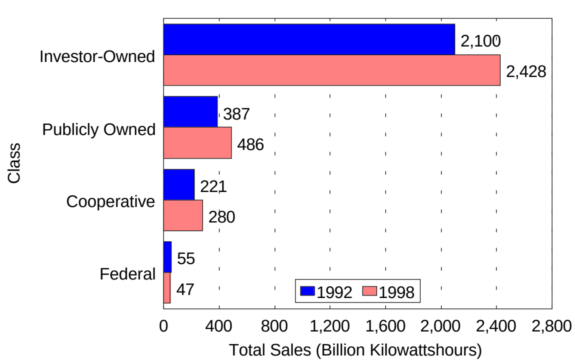
Figure 22. Share of Sales to Ultimate Consumers by Class of Ownership, 1992 and 1998



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

74.9 percent of sales to ultimate consumers. Publicly owned utility sales increased 25.6 percent over 1992 levels and represented 15.0 percent of total sales. Cooperative utility sales increased 26.7 percent over 1992 levels and represented 8.6 percent of sales. Federal utility sales experienced a decrease of 14.5 percent from 1992 levels and represented 1.5 percent of the total retail sales in 1998 (Figures 21 and 22).

Figure 21. Sales to Ultimate Consumers by Class of Ownership, 1992 and 1998



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

Conclusion

This chapter has outlined the infrastructure of the electric power industry by defining its components and their respective roles. In addition, it has provided statistics[32] to clarify the roles and has compared current data to historical data to show how the roles are changing due to the opening of competition in the industry. In addition, information was given regarding wholesale and retail sales in an effort to more thoroughly cover the roles of the components of the current electric power industry. Some roles will continue to change throughout the transition from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation. Market forces will replace State and Federal regulators in setting the price and terms of electricity supply and are expected to lead to lower rates for customers. The individual States are moving toward opening their retail markets to competition. Chapter 8 details the role of the States in promoting competition. The following chapter outlines the Federal legislation that has affected the structure and operating procedures of the electric power industry since the 1930s.

[32] Various additional industry summary statistics are provided in Appendix D.

4. The Federal Statutory Background of the Electric Power Industry

Introduction

This chapter describes major Federal legislation that has shaped the electric power industry since the 1930s. It begins by detailing three Acts that have had the most profound effects on the industry's structure—the Public Utility Holding Company Act of 1935 (PUHCA), the Public Utility Regulatory Policies Act of 1978 (PURPA),[33] and the Energy Policy Act of 1992 (EPACT), which led to the issuance of Orders 888 and 889 by the Federal Energy Regulatory Commission (FERC). The remainder of the chapter lists and summarizes other laws which have affected the industry throughout the years. Appended to the end of the chapter is a list of major Supreme Court cases which also have had an impact.

The Public Utility Holding Company Act of 1935

The Public Utility Holding Company Act, enacted in 1935, was aimed at breaking up the unconstrained and excessively large trusts that then controlled the Nation's electric and gas distribution networks. They were accused of many abuses, including "control of an entire system by means of a small investment at the top of a pyramid of companies, sale of services to subsidiaries at excessive prices, buying and selling properties within the system at unreasonable prices, intra-system loans at unfair terms, and the wild bidding war to buy operating companies."[34]

Although more than 100 holding companies existed before PUHCA, almost half of all electricity generated in the United States was controlled by three huge holding companies.[35] The size and complexity of these huge trusts made industry regulation and oversight control by the States impossible. After the collapse of several large holding companies, the Federal Trade Commission (FTC) conducted an investigation after which it criticized the many abuses that tended to raise the cost of electricity to consumers. The Securities and Exchange Commission (SEC) also investigated and "publicly charged that the holding companies had been guilty of '. . . stock watering and capital inflation, manipulation of subsidies, and improper accounting practices.' The general counsel of the FTC went further, claiming that '[w]ords such as fraud, deceit, misrepresentation, dishonesty, breach of trust, and oppression are the only suitable terms to apply.'" [36]

Under PUHCA, the SEC was charged with the administration of the Act and the regulation of the holding companies. One of the most important features of the Act was that the SEC was given the power to break up the massive interstate holding companies by requiring them to divest their holdings until each became a single consolidated system serving a circumscribed geographic area. Another feature of the law permitted holding companies to engage only 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 wholesale electric power sales. The law contained a provision that all holding companies had to register with the SEC, which was authorized to supervise and regulate the holding company system. Through the registration process, the SEC decided whether the holding company would need to be regulated under or exempted from the require-

[33] PUHCA and PURPA are now being targeted for repeal due to the industry's transition to competition. Chapter 6 will address the issues and arguments associated with the call for repeal, as well as current proposals for comprehensive restructuring legislation that are before Congress.

[34] L. S. Hyman, *America's Electric Utilities: Past, Present and Future,* Fifth Edition (Arlington, VA: Public Utilities Reports, Inc., 1994), p. 111.

[35] The Securities and Exchange Commission 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.

[36] T. J. Brennan et al., *A Shock to the System: Restructuring America's Electricity Industry* (Resources for the Future: Washington, DC, July 1996), p. 160.

Table 6. Relative Size of Registered Holding Companies as of December 31, 1998

Holding Company System	Consolidated Assets (thousand dollars)	Twelve Months' Consolidated Operating Revenues (thousand dollars)	Number of Customers	Retained Earnings[a] (thousand dollars)
Allegheny Energy, Inc. (E)	6,747,793	2,576,436	1,418,353	836,759
Alliant Energy Corp. (E) (G)	4,959,000	2,131,000	1,295,500	537,372
Ameren (E) (G)	8,847,439	3,318,208	1,479,365	1,472,200
American Electric Power Co. (E)	19,483,200	6,345,900	3,022,479	1,683,561
Central and South West Corp. (E)	13,744,000	5,482,000	1,752,000	1,740,000
CINergy Corp. (E) (G)	10,298,800	5,876,300	1,870,000	945,200
Columbia Energy Group (G)	6,968,700	5,731,800	2,100,000	409,544
Conectiv (E) (G)	6,100,000	3,100,000	1,049,706	276,939
Consolidated Natural Gas Co. (G)	6,361,900	2,760,400	1,880,000	1,591,543
Eastern Utilities Associates (E)	1,302,638	538,801	305,018	56,062
Entergy Corp. (E)	22,848,023	11,494,772	2,495,000	2,526,888
GPU Corp. (E)	16,288,109	4,248,792	2,041,000	2,230,425
National Fuel Gas Co. (G)	2,684,459	1,248,000	704,217	428,112
New Century Energies (E) (G)	7,672,000	3,610,900	2,658,000	740,677
New England Electric System (E)	5,070,535	2,420,533	1,363,000	998,912
Northeast Utilities (E)	10,387,381	3,767,714	1,729,250	560,769
PECO Energy Power Co. (E)	118,000	18,500	NA	NA
Southern Co. (E)	36,192,000	11,403,000	3,794,000	3,878,000
Unitil Corp. (E) (G)	376,855	149,639	114,500	36,401
Total	**186,450,832**	**76,222,695**	**31,071,388**	**20,949,364**

[a]Retained earnings are the balance, either debit or credit, of appropriated or unappropriated earnings of an entity that are retained in the business.

E = Electric.

G = Gas.

NA = Not applicable.

Source: Securities and Exchange Commission, *Financial and Corporate Report* (Washington, DC, July 1, 1999), p. 3.

ments of the Act. The SEC also was charged with regulating the issuance and acquisition of securities by holding companies. Strict limitations on intrasystem transactions and political activities were also imposed.[37]

The holding companies at first resisted compliance, and some challenged the constitutionality of the Act, but the Supreme Court upheld PUHCA's legality. By 1947, virtually all holding companies had undergone some type of simplification or integration, and by 1950 the utility reorganizations were virtually complete.[38] As of December 31, 1998, there were only 15 registered holding companies in the Unites States (Table 6). Additionally, there were 53 holding companies exempt from SEC regulation by SEC order, and 112 holding companies exempt since they fell under the umbrella of PUHCA Section 3 (a) (1) and / or (2), which states:

> *The Commission . . . shall exempt any holding company, and every subsidiary company thereof . . . from any . . . provisions of this title . . . unless 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 . . . are predominantly intrastate in character and carry on their business substantially in a single State in which such holding company and every such subsidiary company thereof are organized;*

[37] 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.

[38] J. Seligman, *The Transformation of Wall Street and The History of the Securities and Exchange Commission in Modern Corporate Finance*, (Boston, MA: Houghton, Mifflin Company, 1982), p. 134.

> *(2) such holding company is predominantly a public utility company whose operations . . . do not extend beyond the State in which it is organized and States contiguous thereto.*[39]

Although PUHCA reform or outright repeal is being considered today because of the move to restructure (see Chapter 6), the same plea for change has been made several times over the past 20 years. In the 1970s, utilities sought relief from PUHCA constraints to diversify into nonutility lines of business as a means to improve their declining profits. In the 1980s, they sought to diversify to exploit the positive experience of independent power producers under PURPA, which eliminated PUHCA constraints on certain qualifying generating facilities. It was not until 1992 that EPACT significantly modified PUHCA by allowing both utilities and nonutilities to build, own, and operate power plants for wholesaling electricity in more than one geographic area. A more detailed discussion of the effects of PURPA and EPACT on PUHCA provisions follows.

The Public Utility Regulatory Policies Act of 1978

In October 1973, Nations of the Organization of Petroleum Exporting Countries (OPEC) 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. This Act, which was signed into law in November 1978, comprises five different statutes: PURPA, the Energy Tax Act, the National Energy Conservation Policy Act, the Powerplant and Industrial Fuel Use Act, and the Natural Gas Policy Act. 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.[40] Although it had numerous objectives, a primary goal of the National Energy Act was to reduce the Nation's dependence on foreign oil and its vulnerability to interruptions in energy supply. Another was to develop renewable and alternative energy sources.

The most significant part of the National Energy Act of 1978 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 . . .*[41]

Section 210 of PURPA requires electric utilities to interconnect with and buy whatever amount of capacity and energy is offered from any facility meeting the criteria for a qualifying facility (QF) (see inset). It further requires that the utility pay for that power at the utility's own incremental or avoided cost of production.[42] This provision created 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 SEC under PUHCA, and from State rate, financial, and organizational regulation of utilities. It also simplified contracts, streamlined the power sales process, increased financial certainty for creditors and equity sponsors, and generally eliminated several procedural and planning

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

[40] J. H. Minan and W. H. Lawrence, "Federal Tax Incentives and Solar Energy Development," *Energy Law Service*, Monograph 7F (Wilmette, IL, September 1981), p. 5.

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

[42] 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).

problems that had made entry into the electricity market prohibitive for most of the smaller energy producers.[43]

In enacting 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 traditional regulation, which generally sets the price of electricity on the basis of the cost (to the producer) of producing it. The QFs 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 received from the QF or purchasing it from another source. One initial interpretation of avoided cost under PURPA was the cost of additional electricity produced by the utility itself. However, under PURPA's requirements, some utilities had to purchase QF generation even though they already had sufficient supply available to meet demand, either through their own generation or through purchases from other sources.

PURPA Qualification Criteria

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. There is no size limitation for an eligible solar, wind, or waste facility, as defined by section 3(17) (E) of the Federal Power Act. For a non-eligible facility, the power production capacity for which qualification is sought may not exceed 80 megawatts. (Under PURPA provisions, both cogenerators and small power producers cannot have more than 50 percent of their equity interest held by an electric utility.)[a]

Cogenerators

Cogenerators are generators that sequentially or simultaneously produce electric energy and another form of energy (such as heat or steam) using the same fuel source. 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.

For a nonutility to be classified as a cogenerator qualified under PURPA, it must meet certain ownership, operating, and efficiency criteria established by FERC. The operating requirements stipulate the proportion (applicable to oil-fired facilities) of output energy that must be thermal energy, and the efficiency requirements stipulate the maximum ratio of input energy to output energy.

Renewables

A renewable resource is an energy source that is regenerative or virtually inexhaustible. 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 mechanical energy directly through shaft power. Biomass energy is derived from hundreds of plant species, various agricultural and industrial residues, and processing wastes. Industrial wood and wood waste are 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.

For a nonutility to be classified as a small power producer under PURPA, it also must meet certain ownership and operating criteria established by FERC. In addition, renewable resources must provide at least 75 percent of the total energy input. PURPA provisions enabled nonutility renewable electricity production to grow significantly, and the industry responded by improving technologies, decreasing costs, and increasing efficiency and reliability.

[a] For further information regarding criteria, refer to http://frwebgate.access.gpo.gov.

In the mid-1980s, several States began to review their own and others' experiences with PURPA implementation. 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 had previously decided that avoided-cost rates for QFs were to be based on the cost of production of electricity by nuclear facilities. These high rates spurred a larger volume of offers than CMP needed. The switch to market-based pricing provided

[43] Energy Information Administration, *Renewable Energy Annual 1995*, DOE/EIA-0603(95) (Washington, DC, December 1995), p. xxvi.

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.[44]

The Energy Policy Act of 1992

In 1992, President George Bush signed the Energy Policy Act (EPACT). The Act substantially reformed PUHCA and made it even easier for nonutility generators to enter the wholesale market for electricity by exempting them from PUHCA constraints. The law created a new category of power producers, called exempt wholesale generators (EWGs).[45] By exempting them from PUHCA regulation, the law eliminated a major barrier for utility-affiliated and nonaffiliated power producers who want to compete to build new non-rate-based power plants. EWGs differ from PURPA QFs in two ways. First, they are not required to meet PURPA's cogeneration or renewable fuels limitations. Second, utilities are not required to purchase power from EWGs. Marketing of EWG power has come to be facilitated by transmission provisions that gave FERC the authority to order utilities to provide access to their transmission systems.

The law has been hailed by industry analysts as one of the most significant pieces of legislation in the history of the industry. In addition, the law amended the wholesale transmission provisions of the Federal Power Act. These transmission provisions have led to a nationwide open-access electric power transmission grid for wholesale transactions. (The law specifically prohibits FERC from ordering retail wheeling—the transmission of power to a final customer.) Independent power producers, publicly owned utilities, rural cooperatives, and industrial producers (i.e., anyone selling power at wholesale) gained the ability to seek from FERC orders that 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 characteristics of EPACT were the expansion of FERC's authority and the creation of EWGs that were exempt from SEC regulation. A bitter dispute was in the area of transmission access. Some nonutility groups had argued that not revising transmission-access rules would reinforce the utility monopolistic structure. The main thrust of the argument against these transmission access authority revisions 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 restricted exceptions to this generalization. One is the requirement, under PURPA, that utilities interconnect with and purchase power from QFs. Another is that under the Federal Power Act, as amended by PURPA, FERC had the authority to require wheeling under limited circumstances. But, in its first deliberation on this authority, FERC found that the 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.[46] This interpretation of PURPA circumscribed the conditions under which FERC could order wheeling but FERC's interpretation was later upheld by the courts. The enactment of EPACT in 1992 broadened FERC's authority to order utilities to provide wheeling over their transmission systems to utilities and nonutilities. In addition, anti-trust laws and analyses have been used to require access to transmission and generation capacity. FERC's implementation of EPACT and open transmission access is discussed in Chapter 7.

The following table lists Federal legislation which has impacted the electric power industry since 1933.

[44] W. H. Wellford and H. 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.

[45] An EWG is a corporate entity. An EWG-owned facility is called an "eligible facility." In this report, "EWG" refers to an EWG-owned eligible facility.

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

Major Federal Legislation Affecting the Electric Power Industry

Tennessee Valley Authority Act of 1933
(Public Law 73-17)

Under this law, the Federal Government provided electric power to States, counties, municipalities, and nonprofit cooperatives. It was the steady continuation of Federal initiatives to provide navigation, flood control, strategic materials for national defense, electric power, relief of unemployment, and improvement of living conditions in rural areas. The Tennessee Valley Authority (TVA) was also authorized to generate, transmit, and sell electric power. With regard to the sale of electric power, the TVA is authorized to enter into contracts up to 20 years for sales to governmental and private entities, to construct transmission lines to areas not otherwise supplied with electricity, to establish rules and regulations for power sales and distribution, and to acquire existing electric facilities used in serving certain areas.

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

PUHCA was enacted to remedy utility industry abuses facilitated by the holding company structure. PUHCA gave the Securities and Exchange Commission the authority to oversee utility holding companies pursuant to the extensive set of regulations provided by the Act.

Federal Power Act of 1935 (Title II of PUHCA)
(Aug. 26, 1935, ch. 687, Title II, 49 Stat. 838)

This Act was passed to provide for a Federal mechanism for interstate electricity regulation.

Rural Electrification Act of 1936
(Public Law 74-605)

This Act established the Rural Electrification Administration (REA) to provide loans and assistance to organizations providing electricity to rural areas and towns with populations under 2,500. REA cooperatives are generally associations or corporations formed under State law. The predecessor to this Act was the Emergency Relief Appropriations Act of 1935, which performed the same function.

Bonneville Project Act of 1937
(Public Law 75-329)

This Act created the Bonneville Power Administration (BPA), which pioneered the Federal power marketing administrations. The BPA was accountable for the transmission and marketing of power produced at Federal dams in the Northwest. In 1953, the BPA first guaranteed the bonds of and a market for small energy facilities built and financed by public utility districts.

Reclamation Project Act of 1939
(Public Law 76-260)

This Act requires that rates for electric power generated at Federal hydroelectric projects be sufficient to recover an appropriate share of annual operation and maintenance costs and an appropriate share of construction costs, to include interest charged at a rate of not less than 3 percent.

Flood Control Act of 1944
(Public Law 78-534)

This Act formed the basis for the later creation of the Southeastern Power Administration (SEPA)[a] in 1950 to sell power produced by the U.S. Army Corps of Engineers in the Southeast; and the Alaska Power Administration (APA)[b] in 1967 to both operate and market power from two hydroelectric plants in Alaska: the Eklutna Project and the Snettisham Project. Although the Southwestern Power Administration's (SWPA)[c] authority after World War II came from the Flood Control Act of 1944, it was established using the Executive Branch's emergency war powers authority to satisfy the growing demands from weapons development and domestic needs. This Act also demands that rates for electric power be enough to recover the cost of "producing and transmitting such electric energy."[d]

Major Federal Legislation Affecting the Electric Power Industry (Continued)

First Deficiency Appropriation Act of 1949
(Public Law 81-71)

The Act authorized the Tennessee Valley Authority to construct thermal-electric power plants for commercial electricity sale.

Energy Supply and Environmental Coordination Act of 1974 (ESECA)
(Public Law 93-319)

This Act allowed the Federal Government to prohibit electric utilities from burning natural gas or petroleum products.

DOE Organization Act of 1977
(Public Law 95-91)

In addition to forming the Department of Energy (including the Federal Energy Regulatory Commission), this Act provided authority for the establishment of the Western Area Power Administration (WAPA)[e] and transferred power marketing responsibilities and transmission assets previously managed by the Bureau of Reclamation to WAPA. WAPA's authority was extended through the Hoover Power Plant Act of 1984. This Act also transferred the other four power marketing administrations (PMAs)—the Southeastern Power Administration, the Southwestern Power Administration, the Alaska Power Administration, and the Bonneville Power Administration—from the Department of the Interior to the Department of Energy.

National Energy Act of 1978
(Public Law 95-617 - 95-621)

This Act was signed into law in November 1978 and includes 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). Passed in the wake of the oil-producing nations' ban on oil exports to the United States and retail oil price increases, its general purpose 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.

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 1970s. 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. Further, PURPA gave FERC the authority to order wheeling under the FPA.

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 1970s. 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 generally were curtailed as a result of tax reform legislation in the mid-1980s.

National Energy Conservation Policy Act of 1978
(Public Law 95-619)

This Act required utilities to develop residential energy conservation plans to encourage slower growth of electricity demand.

Powerplant and Industrial Fuel Use Act of 1978
(Public Law 95-620)

This Act succeeded the Energy Supply and Environmental Coordination Act of 1974, and extended Federal prohibition on the use of natural gas and petroleum in new electric power plants.

Major Federal Legislation Affecting the Electric Power Industry (Continued)

Pacific Northwest Electric Power Planning and Conservation Act of 1980
(Public Law 96-501)

This Act created the Pacific Northwest Electric Power and Conservation Council to coordinate the conservation and resource acquisition planning of the Bonneville Power Administration (BPA). The Act also provides for BPA to purchase and exchange electric power with Northwest utilities at the "average system cost." Approval of the methodology for determining "average system cost" is required. This Act also gave the BPA the authority to plan for and acquire additional power to meet its growing load requirements.

Economic Recovery Tax Act of 1981
(Public Law 97-34)

This Act introduced a new methodology for determining allowable tax depreciation deductions. The new methodology, the *Accelerated Cost Recovery System (ACRS)*, set forth rules enabling taxpayers to claim generous depreciation deductions based on the system's permitted depreciable life, method, and salvage value assumptions. The generation, transmission, and distribution plants of regulated electric utilities were categorized as public utility property. Public utility property under ACRS was assigned relatively long depreciable lives.

Electric Consumers Protection Act of 1986 (ECPA)
(Public Law 99-495)

This Act was the first significant amendment to the hydro licensing provisions of the FPA since 1935. "The amendments have made four principal changes to Part I of the FPA. First, the municipal preference on relicensing has been eliminated. Second, the importance of environmental considerations in the licensing process has been greatly increased and the role of the State and Federal fish and wildlife agencies is expanded. Third, PURPA benefits for hydroelectric projects at new dams and diversions were eliminated unless the projects satisfy stringent environmental conditions. Finally, FERC's enforcement powers have been increased substantially."[f]

Tax Reform Act of 1986
(Public Law 99-514)

Under this Act, ACRS was replaced with the *Modified Accelerated Cost Recovery System (MACRS)*. Under MACRS, the disparity in treatment of property between regulated and nonregulated taxpayers was eliminated. The investment credit was also repealed. The investment credit of the Federal income tax law was a dollar-to-dollar offset against the taxes payable by the taxpayer. The investment credit was available for regulated and nonregulated taxpayers and was intended to encourage capital investment by the Nation's businesses. The credit continues to be of importance to regulated utilities, however, because it is generally amortized for ratemaking and financial reporting purposes over the regulatory life of the related property that gave rise to the credit.

Clean Air Act Amendments of 1990 (CAAA)
(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.

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

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

[a]SEPA markets power in West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Tennessee, and Kentucky. SEPA is unique from the other marketing authorities because it does not own any transmission lines.

[b]The APA and the TVA are the only two Federal marketing organizations that operate their own plants.

[c]SWPA markets power in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

[d]Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1994,* DOE/EIA-0437(94)/2 (Washington, DC, December 1995), p. 458.

[e]The territory served by WAPA includes 15 Central and Western States of Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah, and Wyoming. The WAPA's authority was lengthened through the Hoover Power Plant Act of 1984 to constrain customer utilities to address certain conservation activities and to retain a part of customers' power allocations if they did not follow.

[f]D. J. Muchow and W. A. Mogel, *Energy Law and Transactions* (Matthew Bender, April 1996), p. 53-20.

Note: Although it is not a law, the Uniform Division of Income for Tax Purposes Act (UDITPA)—which provides that the sale of electricity is sourced for apportionment purposes to the ultimate destination State—has been adopted in some form by 44 States from a total of 47 States that impose a corporate income tax. Public laws before 1935 were sourced differently than those after 1935. For more information on the power marketing administrations, refer to Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1994*, DOE/EIA-0437(94)/2 (Washington, DC, December 1995).

Source: This inset is based on information compiled by the Office of Coal, Nuclear, Electric and Alternate Fuels from various documents. These documents include *Congressional Quarterly* as well as others published by the following organizations: the Congressional Research Service, Government Institutes, Inc., the Council on Environmental Quality, the General Accounting Office, and the Federal Energy Regulatory Commission. Also refer to D. J. Muchow and W. A. Mogel, *Energy Law and Transactions* (Matthew Bender, April 1996).

In addition to the preceding statutory background regarding the electric power industry, the inset below provides a synopsis of a related subject—U.S. Supreme Court cases and decisions that have had major impacts on the industry.

Major U.S. Supreme Court Cases Affecting the Electric Power Industry[a]

Court Case	Date	Decision
Munn v. Illinois (94 U.S. 113)	1877	The Supreme Court establishes the rights of government to regulate and set rates for companies that provide vital public services in a business environment.
Smyth v. Ames (169 U.S. 466)	1898	The Supreme Court decrees just compensation on fair value. The decision in this case upheld the right of the State to regulate the prices charged to the public by a business "affected with a public interest."
Rhode Island PUC v. Attleboro (273 U.S. 83)	1927	The Supreme Court declares that selling electricity interstate cannot be regulated by a State.
Ashwander v. TVA (297 U.S. 288)	1936	The Supreme Court upholds the constitutionality of the Tennessee Valley Authority.
Electric Bond & Share v. SEC (303 U.S. 419)	1938	The Supreme Court upholds the Public Utility Holding Company Act of 1935.
Tennessee Electric Power Co. v. Tennessee Valley Authority (306 U.S. 118)	1939	The Supreme Court rules in TVA's favor, despite the claims that TVA threatened the large investments already made by privately owned utilities. This ruling resulted in TVA becoming a major electricity supplier in the region.
F.P.C. v. Hope Natural Gas (320 U.S. 591)	1944	The Supreme Court closes a longstanding dispute by allowing either original or replacement cost accounting in utility rate making, so long as just and reasonable rates result.
Otter Tail Power Co. v. United States (410 U.S. 366)	1973	The Supreme Court upholds finding that Otter Tail Power Co. violated Section 2 of the Sherman Act by refusing to sell or wheel wholesale power to proposed municipal systems.

Major U.S. Supreme Court Cases Affecting the Electric Power Industry (Continued)

Court Case	Date	Decision
FPC v. Conway Corp. (426 U.S. 271)	1976	The Supreme Court states that FERC, in setting wholesale rates, must consider allegations that the proposed rates are discriminatory and anticompetitive in effect.
FERC v. Mississippi (456 U.S. 742)	1982	The Supreme Court upholds the constitutionality of PURPA in regards to its preemptive effect on the States' authority.
American Paper Institute v. American Electric Power Service Corp. (461 U.S. 402)	1983	The Supreme Court upholds the constitutionality of FERC's cogeneration rules promoted pursuant to PURPA.
Nantahala Power & Light Co. v. Thornburg (476 U.S. 953)	1986	Among other outcomes, the Supreme Court confirms that FERC has exclusive authority over wholesale electric rates.
Mississippi Power & Light Co. v. Mississippi[b] (487 U.S. 354)	1988	The Supreme Court determines that FERC authority is controlling and that a State commission is obligated to honor a FERC order. The Court stated "FERC-mandated allocations of power are binding on States, and States must treat those allocations as fair and reasonable when determining retail rates."[c]
Duquesne Light Co. v. Barasch[d] (488 U.S. 299)	1989	"U.S. Supreme Court held that absent any showing that a State's rate-making methodology results in unreasonable rates that throw into jeopardy the financial integrity of the utilities or otherwise fail to compensate shareholders for their risks of investment, no impermissible taking exists. Further, the Constitution of the United States does not mandate any particular rate-making methodology for State regulatory commissions."[e]

[a]This inset highlights the major U.S. Supreme Court cases that affect the electric power industry, stating the final decision of the Court without discussing in detail the contents of the case.

[b]This case, Mississippi Power & Light Co. v. Mississippi, continues the holding found by the U.S. Supreme Court in the Nantahala Power & Light Co. v. Thornburg case.

[c]W. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993), p. 149.

[d]This case is a final construction work in progress (CWIP) case. FERC issued a CWIP rule effective July 1, 1983. This means that a utility may include, in its rate base, up to 50 percent of its CWIP costs for ongoing construction projects and for the costs of nuclear fuel in the process of fuel refinement, conversion, enrichment, and fabrication. In addition, the rule continues to permit utilities to include all CWIP costs associated with pollution control and fuel conversion facilities. See W. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993), p. 150.

[e]W. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993), p. 153.

FERC = Federal Energy Regulatory Commission.

TVA = Tennessee Valley Authority.

PG&E = Pacific Gas & Electric Company.

PURPA = Public Utility Regulatory Policies Act.

PUC = Public Utility Commission.

Source: This inset is based on information compiled by the Office of Coal, Nuclear, Electric and Alternate Fuels from various documents from the Department of Energy Library. For more information, refer to D. J. Muchow and W. A. Mogel, *Energy Law and Transactions* (Matthew Bender, April 1996); and W. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993).

Part II:

The U.S. Electric Power Industry in Transition to Competition

5. Factors Underlying the Restructuring of the Electric Power Industry

Introduction

In recent years, economists and public policy analysts have extolled the advantages of competition over regulation and have promoted the idea that free markets can drive down costs and prices by reducing inefficiencies. Competitive industries may also be more likely to spur innovations with new technologies. Recent actions with regard to electric power by legislators and regulators in the United States are evidence of the changing approach to dealing with what until recently has been a regulated monopoly. Originally, protecting consumers was a primary motivation for decisions to impose regulatory constraints on the industry. Today, legislators and regulators are making laws and rules that promote competition across the economy for the same purpose, because they believe that consumers will benefit more from an industry whose members must compete for customers than from an industry composed of regulated monopolies.

One example is the 1999 revocation of the Bank Act of 1933. Like the Public Utility Holding Company Act of 1935 mentioned in Chapter 2 and later outlined in Chapter 4, it was another piece of Depression-era legislation that was believed to have become obsolete. That law had been passed to separate commercial banking from investment banking (the underwriting of securities). Subsequent pressure from both commercial and investment bankers and from the insurance industry, promoting synergies that the Act was ostensibly constraining, led to its repeal.

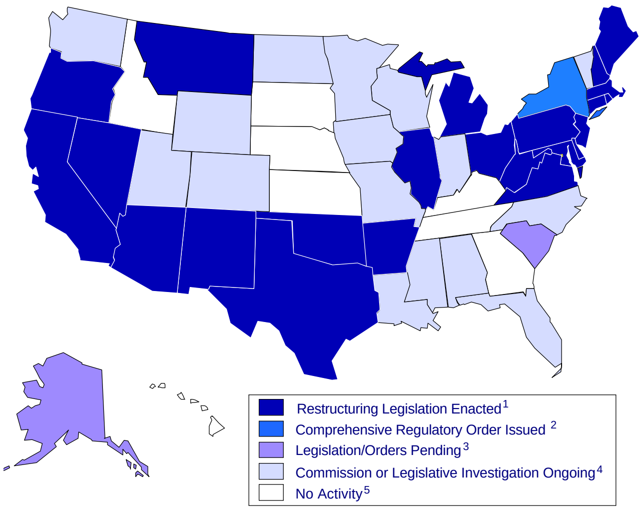
The most important and controversial sections of the Telecommunications Act of 1996, and the Federal Communications Commission's regulations implementing it, concern the unbundling of the local phone company's network elements down to the level of virtual space (bandwidth) within the individual telephone line leading to a residence. The same thinking is now being applied to the electric power industry in that it is now a target for unbundling along similar lines, with power generation and sales being untangled from transmission and distribution services.[47] Other examples of this changed climate can be found throughout the State and Federal levels as well as other countries around the world. In the United States, the Energy Policy Act of 1992 (EPACT) was passed by Congress to promote competition in electricity generation. The recent spate of generating asset sales (some utilities with enormous holdings of generating capacity have sold or are planning to sell their entire inventories) is at least partly a result of EPACT. In 1998, retail sales in deregulated markets occurred in 11 States.[48] With the exception of Missouri, all of these States had deregulated market sales in the industrial sector and all but Idaho, Montana, and Rhode Island had sales to commercial customers in deregulated markets. Those that did not have residential sales in deregulated markets were Idaho, Missouri, Montana, and Washington. As of July 1, 2000, 24 States and the District of Columbia had passed legislation or issued regulatory orders to restructure the electric power industries within their borders. Only eight States have taken little or no action toward restructuring (Figure 23). This changed climate and the legislative and regulatory actions that have resulted are one of the three factors underlying restructuring that are outlined in this chapter.

For most of the industry's history, consumers welcomed the protection that regulation afforded them and felt that this means of oversight assured them of fair prices for electricity. Now, however, consumers themselves are pushing for competition (to both lower prices and increase the variety of suppliers such as green power producers) and regulatory reform. The main thrust is coming from large industrial users of electricity who, in some areas of the United States, have been burdened by high electricity prices while their competitors in other areas pay far less for their electricity. These price differentials are the second factor underlying the restructuring of the industry.

[47] P. Huber, "Is a Breakup Next? Not Likely," *The Wall Street Journal* (April 4, 2000), p. A26.

[48] California, Idaho, Illinois, Missouri, Montana, New Hampshire, New York, Oregon, Pennsylvania, Rhode Island, and Washington.

Figure 23. Status of State Electric Utility Deregulation Activity, as of July 2000



[1]Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia.
[2]New York.
[3]Alaska and South Carolina.
[4]Alabama, Colorado, Florida, Indiana, Iowa, Louisiana, Minnesota, Mississippi, Missouri, North Carolina, North Dakota, Utah, Vermont, Washington, Wisconsin, and Wyoming.
[5]Georgia, Hawaii, Idaho, Kansas, Kentucky, Nebraska, South Dakota, and Tennessee
Source: Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

A third factor that has had a significant impact on restructuring is the technological innovation in the production of electricity. Nonutilities, using recently improved aero-derivative gas turbine technologies to generate electricity, can now do so cheaply enough that merchant plants are being built in many areas of the country where they are permitted.[49] Today, with one exception,[50] the capital costs and both the fixed and variable operations and maintenance costs of combined-cycle plants, and conventional and advanced combustion turbines, are lower than the traditional baseload coal and nuclear technologies.[51] Also, the advanced generators are cleaner than coal plants and some are more efficient. Today's regulatory environment includes market incentives to reduce certain types of pollution.[52] Nonutilities are also able to put advanced generators into operation quickly, sometimes as an alternative to utility capacity that is already built.

The banking industry and telecommunications industry have been discussed as points of comparison for the first factor, the changing climate of economic and regulatory thinking. The following sections analyze the more quantifiable factors that are motivating the structural changes in the electric power industry—price differences and technological advances. The analyses include EIA data to measure these factors where they are relevant.

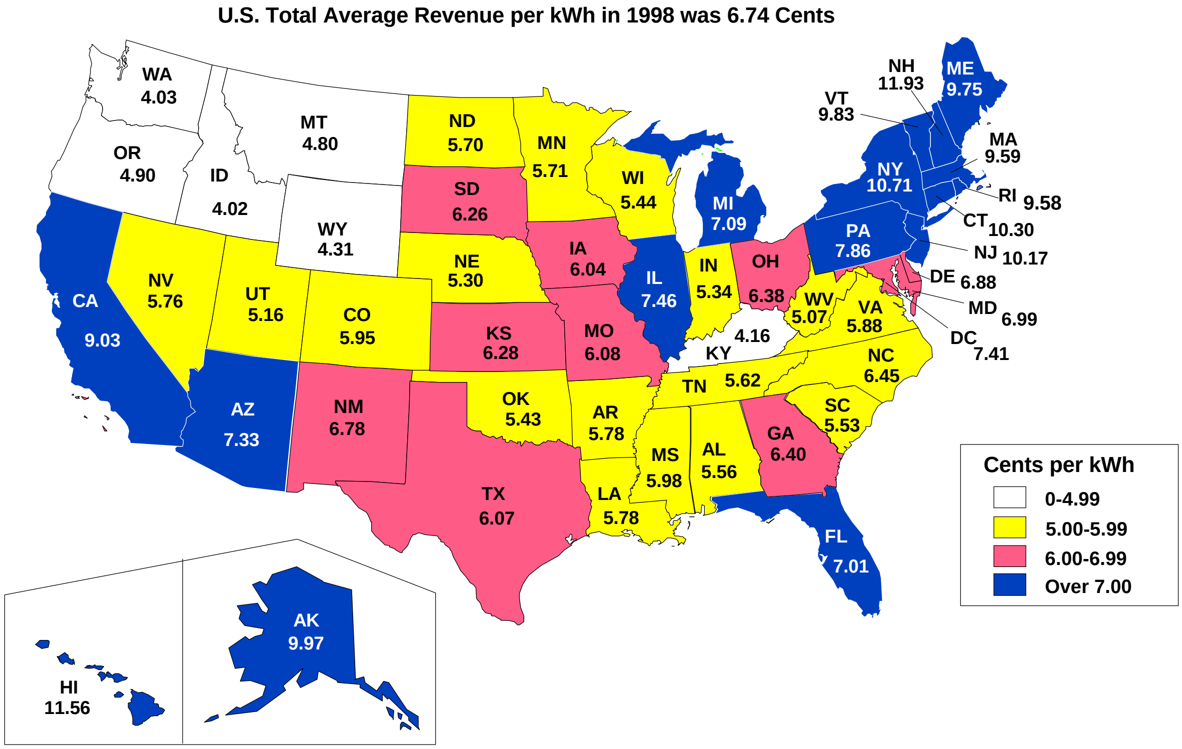
Price Differences

While restructuring originated with the Public Utility Regulatory Policies Act of 1978, large differences in the retail prices of electricity have continued to motivate some to advocate expanded restructuring. The current structure of the electric power industry, as mentioned above, provides only a limited number of retail electricity customers—mostly in Pennsylvania, California, Massachusetts, Oregon, and Washington—with the opportunity to purchase electricity from alternative suppliers. Further restructuring of the industry holds the possibility of allowing more choice for more consumers. Many industrial companies, because they are large consumers of electricity and have a lot to gain if they can reduce their average price of electricity by choosing another provider, are especially prone to advocate further restructuring. They argue that price differentials among utilities provide an advantage to the competitor who is situated in an area with lower electricity prices, and that all consumers should have access to cheaper electricity. Some industrial consumers, who have threatened to purchase power from lower-priced providers, move the location of their companies, or generate their own electricity, often have "succeeded in wringing lower prices from their traditional electric utilities."[53]

In the United States, the average revenue received per unit of electricity sold, i.e., the price to all retail consumers, varies substantially by State (Figure 24). In 1998, the States with average prices of more than 9.5

[49] An exception is Florida, where it was ruled that merchant plants planning to sell their power outside State boundaries cannot be built in the State.
[50] Variable operations and maintenance costs at nuclear plants are less than those at combined-cycle plants.
[51] Energy Information Administration, *Assumptions to the Annual Energy Outlook*, DOE/EIA-0554 (Washington DC, January 2000), Table 37, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.
[52] The Clean Air Act Amendments of 1990 established the Environmental Protection Agency's Acid Rain Program where allowances permitting the emission of sulfur dioxide may be bought and sold on the open market. Similarly, the Amendments led to the establishment of the Ozone Transport Commission which formed a market, albeit regionally limited, for nitrogen oxide allowances.
[53] T.R. Kuhn, et al., "Electric Utility Deregulation Sparks Controversy," *Harvard Business Review* (May/June 1996), p. 150.

Figure 24. Average Revenue per Kilowatthour for All Sectors by State, 1998



kWh = Kilowatthour.

Note: The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. Sales in deregulated retail electricity markets are not included.

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

cents per kilowatthour were the six New England States, New York, New Jersey, Alaska, and Hawaii. Since the 1996 edition of this report, the average revenue from electricity sales to all consumers in the United States has declined from 6.9 cents per kilowatthour to 6.7 cents per kilowatthour.[54] It is not coincidental that many of the States leading the restructuring movement are among the States with high prices. They see restructuring as a means of lowering prices. In contrast, States with average prices below 6 cents per kilowatthour are still scattered throughout the country. Most have average prices for all consumers that are less than one-half those in States with the highest average revenue. These States have less incentive than the higher-cost States to restructure their electricity markets. A similar geographic pattern exists for average electricity prices received from industrial consumers, although industrial consumers yield one-third lower average revenues than all retail customers (Figure 25).[55]

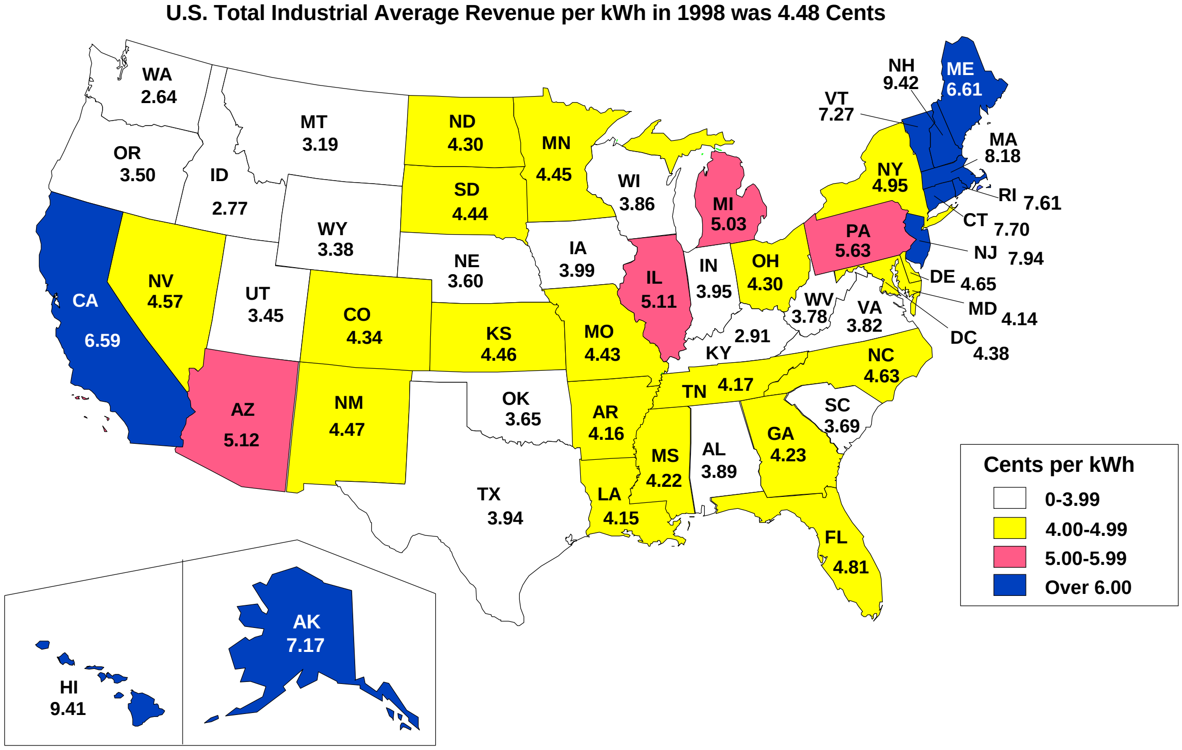
Large industrial electricity consumers typically pay less because it is less costly to service one large customer than many small ones. With this power, industrial consumers have played a substantial role in motivating the restructuring of the electric power industry. Their bargaining power is reflected in the declining trend of industrial prices relative to those paid for all consumers (Figure 26). The relative price industrial consumers paid for electricity rose from the mid-1960s until 1983, then declined from 1983 through 1997, then rose slightly in 1998, but not to the level it had been in 1996. Because real average revenues from both groups have been falling since 1983, the relatively lower revenues for industrial consumers indicate that their average price has been falling faster than the average price charged to all consumers.

Over the years, utilities have developed programs to help lower the price of electricity to the industrial sector.

[54] Both numbers are in nominal units.

[55] Because industrial consumers usually use larger amounts of electricity than other consumers, and because they usually take it at higher voltages, the cost of providing each unit of electricity to them is lower.

Figure 25. Average Revenue per Kilowatthour for the Industrial Sector by State, 1998

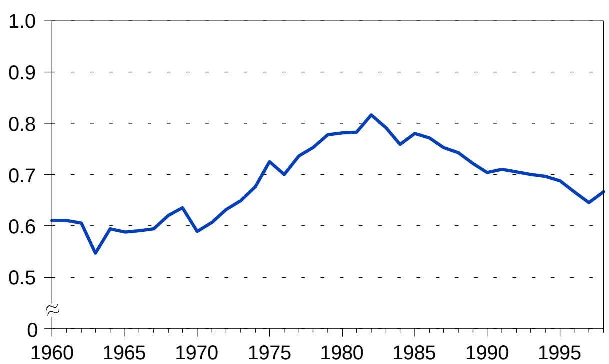


kWh = Kilowatthour.

Note: The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. Sales in deregulated retail electricity markets are not included.

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

Figure 26. Relative Average Revenue of Electricity Sales: Ratio of Industrial Consumers to All Consumers, 1960-1998



Source: Energy Information Administration, *Annual Energy Review 1998,* DOE/EIA-0384(98) (Washington, DC, July 1999), Table 8.13.

They traditionally have relied on alternative rate design approaches, such as interruptible service and time-of-use rates to reduce the time-variation of demand by the industrial sector. The programs also use technological approaches, such as thermal storage. A number of utilities have developed flexible custom measure programs, which allow industrial energy users and utilities to work together to identify cost-effective programs.

Technological Advances

Restructuring has been sustained primarily by technological improvements in gas turbines. "In areas with cheap... natural gas—most notably the United States—gas turbines [are] the least cost option [for new electricity generating capacity].[56] These improvements also have recast economies of scale in electric power generation technologies. No longer is it necessary to build a 1,000-megawatt generating plant to exploit economies of scale.

[56] H.R. Linden, "The Revolution Continues," *The Electricity Journal* (December 1995), p. 54.

Combined-cycle gas turbines reach maximum efficiency at 400 megawatts, while aero-derivative gas turbines can be efficient at scales as small as 10 megawatts.[57] Indeed from 1996 through 1998, gas-fired and gas- and oil-fired capacity brought on-line was almost two-thirds of the total. The average capacity of these units was 65 megawatts.[58]

In its modeling of the electric power industry, the Energy Information Administration (EIA) compares the estimates of the costs of different generating technologies. In its forecasts, "it is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints."[59] The reference case forecast released by EIA in late 1999 projects that, of the 300 gigawatts of new generating capability projected to be added by electric generators between now and 2020, 90 percent will be either combined-cycle or combustion turbine technology (Table 7)[60] as nonutilities move toward less capital intensive projects.[61] Both technologies are designed primarily to supply peak and intermediate capacity but combined-cycle technology can also be used to meet baseload needs. The reduction in baseload nuclear capacity also has an impact on the electricity outlook after 2010. Almost half of the new combined-cycle capacity projected over the entire forecast period is expected to be brought on line in those 10 years, due in part to nuclear retirements. Another relative advantage of combined-cycle technology as a source of baseload capacity is the shorter leadtime needed for construction.

Table 7. Total Projected Additions of Electricity Generating Capability for Electric Generators by Technology Type, 1999-2020
(Gigawatts)

Technology	Capability Additions
Coal Steam	21.1
Combined Cycle	135.2
Combustion Turbine/Diesel	133.8
Fuel Cells	0.1
Renewable Sources	9.7
Total	**299.9**

Source: Energy Information Administration, AEO2000 National Energy Modeling System run AE02K.D100199A.

Both advanced and conventional combined-cycle technologies require only 3 years while a coal or nuclear plant needs 4 years.[62] H.R. Linden writes in *The Electricity Journal* that "under pressure of competition, the all-in cost of a combined-cycle plant has dropped to $450 per kilowatt, less than half that of a new clean coal plant. In combined-cycle configurations, heat rates have dropped. This has made natural gas at $2.50 / million Btu competitive with coal in terms of variable cost when the much lower non-fuel operating and maintenance costs of gas are figured in."[63]

The following chapter outlines the major issues that are framing the current debate over Federal initiatives to facilitate the industry's transition to a competitive market environment.

[57] R.E. Balzhiser, "Technology - It's Only Begun to Make a Difference," *The Electricity Journal* (May 1996).

[58] Energy Information Administration, *Inventory of Nonutility Electric Power Plants in the United States 1998*, DOE / EIA-0095(98) / 2 (Washington, DC, December 1999), p. 7 and EIA, *Inventory of Electric Utility Power Plants in the United States 1999*, DOE / EIA-0095(99) (Washington, DC, November 1999), p. 11.

[59] Energy Information Administration, *Annual Energy Outlook 2000*, DOE / EIA-0383(2000) (Washington, DC, December 1999), p. 233.

[60] Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

[61] Remarks of Jay Hakes, Administrator, Energy Information Administration, North American Gas Strategies Conference (Calgary, Alberta, October 19, 1998).

[62] Energy Information Administration, *Assumptions to the Annual Energy Outlook,* DOE / EIA-0554 (Washington DC, January 2000), Table 37, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.

[63] H.R. Linden, "Operational, Technological, and Economic Drivers for Convergence of the Electric Power and Gas Industries," *The Electricity Journal* (May 1997).

6. Federal Legislative Initiatives

Introduction

Even with the changes that have been spurred by the factors discussed in the previous chapter, there are still statutory and regulatory limitations at both the Federal and State levels[64] on how quickly and how far restructuring can proceed. This chapter examines the restructuring initiatives of the U.S. Congress. A number of bills were introduced in the 106th Congress as well as in the past two Congresses which dealt with the deregulation of the electricity industry. Hearings, debates, and panels were held to determine the issues that must be addressed and decided. All groups associated with the electric power industry have been given a chance to be heard. As of July 1, 2000, 18 legislative proposals dealing with the electric power industry were pending in the House of Representatives and 13 in the Senate.[65] Some of these bills addressed all of the issues surrounding the restructuring of the industry and are considered "comprehensive" legislation. Others addressed several closely related issues and still others concentrated on just one of the issues, for example bulk power reliability or tax-exempt financing by governmentally owned utilities. The latter have come to be known as "stand-alone" restructuring legislation. Stand-alone proposals receive strong support among some groups because they believe that this type of legislation can move through the legislative process quickly while others contend that this is a short-sighted and unsatisfactory "piece-meal" approach.

The Clinton Administration has been pressing Congress to reach consensus and enact comprehensive legislation without further delay.[66] The Administration has stressed that more delays will result in a significant decrease in the reliability of the Nation's supply of power due to the ever-increasing demand for electricity coupled with the fact that needed investments in new generating capacity are being stymied due to investors' uncertainties during the industry's transition. The Administration had also made it known that, although reliability is at the forefront of the critical issues, they were not in support of a stand-alone bill that addressed reliability. However, some committee members stressed the necessity of such action if a workable comprehensive proposal could not be ironed out quickly. Consequently, the Senate Energy and Natural Resources Committee came to a decision in late June, 2000 to end their pursuit of comprehensive restructuring legislation because it was unlikely that it could be promulgated before the current Congress ends. Instead, they unanimously reported the stand-alone reliability legislation introduced by Senator Slade Gorton (R-WA).[67] This bill ". . .would pave the way for FERC to designate the North American Electric Reliability Organization . . . as the developer and enforcer of electric reliability standards in the United States, under Federal Energy Regulatory Commission (FERC) supervision. The Committee approved the bill with an amendment that reflects industry consensus on State vs. Federal jurisdiction over reliability."[68]

On the House of Representatives side, Commerce Committee members have stated that they are still hoping to move ahead with a full-committee mark-up of a comprehensive bill before the end of this year's session.[69] This bill was the only comprehensive proposal to move forward in the 106th Congress. The reason for this

[64] While each of the States have examined retail competition and most of them have taken steps toward that end, there is a consensus among many interested parties that there must be a Federally guided transition to competition to ensure reliability of the national grid.

[65] In the House of Representatives, legislation dealing with electricity deregulation is introduced and referred to the Energy and Power Subcommittee, chaired by Congressman Joe Barton (R-TX). Once this Subcommittee has marked-up a bill, it is passed on to the full committee, the Committee on Commerce, chaired by Congressman Tom Bliley (R-VA). In the Senate, legislation dealing with electricity deregulation is introduced and referred to the Subcommittee on Water and Power, chaired by Senator Slade Gorton (R-WA) then passed on to the full committee, the Energy and Natural Resources Committee, chaired by Senator Frank Murkowski (R-AK).

[66] In early 1999, the Administration submitted to Congress a comprehensive restructuring proposal entitled "The Comprehensive Electricity Competition Act." It was introduced by Senator Frank Murkowski (R-AK) on May 13, 1999. See Appendix C for a summary.

[67] Refer to Appendix C for details on S. 2071, "The Electric Reliability 2000 Act," introduced by Senator Slade Gorton (R-WA).

[68] "Senate Panel Abandons Restructuring Legislation; Approves Reliability Bill," *Public Power Daily* (June 21, 2000).

[69] This bill is H.R. 2944, "The Electricity Competition and Reliability Act of 1999," introduced by Congressman Joseph Barton (R-TX) on September 24, 1999. See Appendix C for a summary.

Major Electric Power Industry Restructuring Issues Before Congress

- Mandatory participation in a regional transmission organization (RTO)
- Bulk power reliability
- Nuclear decommissioning provisions
- Transmission expansion and construction
- Reform of the Tennessee Valley Authority and Federal power marketing administrations
- Federal authority to regulate retail sales, protect retail consumers, or regulate local grid interconnections
- Utility mergers
- Public benefits fund
- Retail net metering
- Emissions caps and standards for generators
- IRS restrictions on “private use” of municipal electric systems
- State/Federal jurisdiction clarification
- Retail sales to Federal agencies
- Retail reciprocity
- Extension of Order 888 wholesale wheeling rules to transmission by municipals, cooperatives, Federal power marketing administrations, and the Tennessee Valley Authority
- Renewable portfolio standards
- Repeal of PUHCA and Section 210 of PURPA[a]

[a]Repeal of PUHCA and Section 210 of PURPA are discussed in more detail later in this Chapter.

seeming lack of progress can be attributed to the fact that reaching compromise and consensus on the number of issues involved in restructuring the electric power industry is a monumental task. The inset box above lists the major issues that have been considered and debated. Underlying each of these issues are complex details which must be addressed. In addition, the pro and con arguments of a vast number of stakeholders with diverse interests have been heard and must be taken into account. The committee members themselves have been divided on various issues and must make decisions that will benefit not only the national economy and the industry, but also their varied constituencies. For instance, members who represent States or districts that already enjoy lower than average rates for electricity are concerned that certain actions, which may benefit the Nation as a whole, could result in an increase in rates for their electorate.

Major Issues Under Debate

The following paragraphs detail several of the more controversial of the issues mentioned above (reliability, regional transmission organizations, a renewable portfolio standard, and repeal of the Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act of 1978 (PURPA)) followed by a synopsis of the Clinton Administration’s Comprehensive Electricity Competition Plan.

Reliability

Voluntary compliance by electric utilities with procedures for ensuring the reliability of the power system, which were established by the North American Electric Reliability Council (NERC) and its member Regional Reliability Councils, has worked effectively over the past three decades. However, with the emergence of competition and the multitude of changes taking place in the industry over the past few years, industry leaders and government officials are concerned that the reliability of the system may be threatened. Many officials believe that a voluntary approach is no longer adequate, and that Federal legislation establishing mandatory reliability rules is required to ensure that competition does not compromise the reliability of the transmission system. A number of House and Senate bills contain provisions that would lead to mandatory reliability standards for electric utilities to follow.

Administration and enforcement of mandatory reliability standards is also an issue. One approach suggested in pending Federal legislation, would be to create an independent reliability organization, such as NERC, with FERC having some sort of oversight responsibility for establishing the reliability standards. The appropriate role of the States in establishing and enforcing standards is also an issue. State regulators want to maintain some control over the quality of service received by customers in their respective States. Federal legislation dealing with reliability will have to address, in some manner, the appropriate organization structure for enforcing reliability standards, and jurisdictional authority between Federal and State regulators.

In August of 1999, Secretary of Energy Bill Richardson formed DOE's Power Outage Study Team. The Team's purpose was to study significant electric power outages and other disturbances that occurred across the Nation during the summer of 1999 and to recommend appropriate Federal actions to avoid electric power disturbances in the future. The first step was to meet with relevant utilities, independent system operators, and regulators in areas where outages and disturbances occurred. The Team's findings were published in an Interim Report issued in January 2000. Subsequently, three workshops were held to solicit recommendations from electric industry stakeholders on possible approaches to address the issues raised by the Team's findings. A Final Report was given to the Secretary on March 13, 2000, containing the Team's findings along with 12 recommendations for Federal lawmakers. Secretary Richardson stressed that "Congress must move ahead to make changes in the Federal statutory framework to provide the certainty that is needed to achieve reliable electric service in competitive wholesale and retail markets."[70]

Regional Transmission Organization Issues

In December 1999, FERC released Order 2000 calling for the voluntary formation of regional transmission organizations (RTOs). FERC believes that RTOs will facilitate the continued development of competitive wholesale power markets and will lead to improvements in reliability and management of the transmission system. (Chapter 7 has a detailed discussion of Order 2000). In order for an RTO to be fully effective, all of a region's transmission system must be controlled by the RTO. Its effectiveness and the benefits cannot be achieved if portions of the transmission system are left out.

Although voluntary participation in RTOs was requested, FERC has determined that it has the authority under Sections 205 and 206 of the Federal Power Act to order public utilities, primarily investor-owned utilities, to participate in RTOs on a case-by-case basis, if necessary, to remedy undue discrimination or anticompetitive activities of electric utilities. FERC believes that Federal legislation is needed to reinforce the Commission's authority to order public utilities to participate in an RTO, if the voluntary approach does not succeed. The above authority refers primarily to investor-owned utilities. To cover the entire transmission grid, FERC also needs similar authority with respect to municipal electric utilities, rural cooperatives, and Federally owned utilities.

Renewable Portfolio Standard

There have been a number of proposals for a renewable energy portfolio standard. Such a standard would require that any company selling electricity in a competitive market include some amount of renewable energy as part of its portfolio of generating fuels. The portfolio standard would more or less be competitively neutral, i.e., it would have to impose an equal obligation on any company selling electricity in any State.

Definitions would have to be made regarding which renewable resources were eligible. For instance, the Clinton Administration does not include hydroelectricity in the renewable portfolio section of its restructuring proposal. Purchase requirements would have to be decided upon, and the level of the standard needs to be determined. In addition, enforcement of the standard would have to be addressed as well as penalties for failure to meet the standard.

The main differences among the various renewable portfolio standards proposals are the required renewable share, the timing of the program, the definition of qualifying facilities, and whether or not there is a limit (cap) on the allowable price for renewable credits. For example, the Administration's proposed Comprehensive Electricity Competition Act, submitted to Congress on April 15, 1999, includes a Federal renewable portfolio standard that would apply to all U.S. electricity suppliers. The key provisions of the Act that pertain to a renewable portfolio standard are:

- The required renewable share of electricity sales would be set at 2.4 percent for the years 2000 to 2004, increase to 7.5 percent by 2010, and then

[70] Copies of the *Report of the U.S. Department of Energy's Power Outage Study Team: Findings and Recommendations to Enhance Reliability from the Summer of 1999* are available from DOE's Office of Public Inquiries, (202) 586-5575, and on the Internet at www.policy.energy.gov/electricity/postfinal.pdf.

remain at 7.5 percent through 2015, after which it would expire (sunset).

- Qualifying renewables would include geothermal, biomass (including biomass used in coal-fired plants), solar thermal, solar photovoltaic, wind, and the portion of municipal solid waste (MSW) that consists of biomass products.

- The price for renewable credits would be capped at 1.5 cents per kilowatthour. If the market price for the credits rose above the cap, electricity retailers would be able to purchase credits from the U.S. Department of Energy (DOE) at the 1.5-cent price (with the resulting revenues deposited in a Public Benefits Fund). In that event, the qualifying renewable share actually achieved would fall below the required 7.5-percent share.[71]

Critics believe that a renewable portfolio standard will increase costs to consumers. They also argue that customers and the market should be able to select what types of electricity sources are used rather than be mandated to select one over another. These critics also say that promulgating a portfolio would also provide an unfair market advantage to renewable energy technologies. However, supporters argue that the portfolio standard would help diversify the Nation's energy supply and would promote environmentally-benign forms of electricity. Supporters further argue that fledgling renewable energy industries would receive a much-needed boost with an increased market demand for renewables.

Repeal of PUHCA

Although the relevancy of PUHCA's provisions are in question today due to the current transitional state of the electric power industry, there is little question that 6 decades ago PUHCA achieved what it was designed to do—break up large, powerful trusts that abused their powers over the Nation's electric and gas distribution networks. However, in today's environment of increasing electric industry competition, there are those who believe that PUHCA's regulations are antiquated and are now impeding the transition to competition. Conversely, others believe strongly that, until the industry completes the transition, PUHCA's regulations must stay in effect in order to protect consumers.

Over the years, the petition for PUHCA repeal has, for the most part, been based on two arguments—that PUHCA has already achieved its goal of restructuring in order to make holding companies manageable and regulated, and that it has been rendered obsolete because of changes that have occurred in the latter part of this century which preclude the holding company abuses of yesterday.[72] They are as follows:

- The development of an extensive disclosure system for all publicly held companies

- The increased competence and independence of accounting firms

- The development of accounting principles and auditing standards and the means to enforce them

- The increased sophistication and integrity of securities markets and securities professionals

- The increased power and ability of State regulators.[73]

Supporters of stand-alone PUHCA-repeal legislation believe that speedy passage is of utmost importance, given the rapidly changing makeup of the electric industry. They contend that the current PUHCA provisions prevent all companies from competing on a level playing field, which some believe is a necessity in a competitive market. Under the prevailing law, the SEC imposes the business and financial restrictions which companies feel are unfair in the current changing environment. The major restrictions include the following: prices for wholesale and retail transactions are set by FERC and State utility commissions, respectively; registered holding companies need SEC approval to own electric and gas operations; mergers and acquisitions require regulatory approval; and the types of businesses in which registered holding companies may engage are severely limited, although exempt wholesale generators (EWGs) do not have the same limitations. While other comprehensive energy legislation that has been introduced contains provisions to repeal PUHCA along with provisions aimed at addressing other restructuring issues, certain interests feel that such comprehensive proposals will take far too long to move through the system. They argue that repeal of PUHCA must be promulgated now through stand-alone legislation.

[71] For information regarding EIA's examination of the potential impacts of these proposed provisions, refer to *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999), p. 18.

[72] For a discussion of these abuses, refer to Chapter 4.

[73] For further discussion of these changes, see Energy Information Administration, *The Public Utility Holding Company Act of 1935: 1935-1992*, DOE/EIA-0563 (Washington, DC, January 1993), p. 23.

Those who are against outright repeal of PUHCA are not arguing that the Act should remain in effect in an open market atmosphere. Rather, they believe that the time is not yet quite right for its repeal. Until the Nation has completed the transition to a fully competitive market, the safeguards that PUHCA provides are necessary. They question the wisdom of removing vital consumer protection mechanisms and leaving the door open to anticompetitive practices by monopolies which are at present aggressively taking actions, such as merging and diversifying, perhaps to increase their market dominance. Most opponents of the legislative proposals to repeal PUHCA stress that what they *are* against is immediate, stand-alone action. Instead, they want to see well-thought-out, comprehensive restructuring legislation that will deal with all deregulation issues, including repeal of PUHCA.

Repeal of PURPA

PURPA was born of the energy crises of the 1970s, which resulted in an intense desire by Congress to reduce the Nation's dependence on foreign oil (and fossil fuels in general) and to diversify the technologies used for electricity generation. PURPA's goal was to cultivate conservation and the efficient use of resources.[74] It was successful in that it promoted cogeneration, the use of renewable resources, and other energy-efficient technologies, and it was fortuitous in that it also introduced competition by demonstrating that the generation of electricity is not a natural monopoly. But, like PUHCA, PURPA is now being targeted for repeal due to the industry's move to competition. There are many arguments on both sides of the debate over the prudence of eliminating PURPA immediately, eventually, or not at all.

Proponents of stand-alone PURPA-repeal legislation contend that the Act's mandatory purchase obligation is grossly anticompetitive and anticonsumer—anticompetitive because the Government created an artificial market by mandating that utilities buy from QFs, and anticonsumer because numerous studies have estimated that the Act caused utilities (and ultimately, consumers) to pay billions of dollars over present market prices for power. They claim that, although the Act introduced competition, it can hardly be said that it did so in an atmosphere of free market participation, a basic tenet of economic theorists who stress that the rules and prices must be established by the market—not by the Government. In addition they assert that, because of EPACT's creation of EWGs and its incorporation of competitive policies, PURPA's QF concept has been overtaken by events, i.e., the industry now realizes that nonutilities can cleanly and efficiently provide additional generating capacity.

Those who want PURPA eliminated now say that its mandatory purchase clause is anticompetitive and is therefore impeding the transition to competition. Furthermore, QFs have been receiving long-run avoided-cost rates that today substantially exceed current market prices. These rates were based on past forecasts of sharply rising oil and natural gas prices as well as the expectation of future increases in the demand for electricity and construction of new generating capacity. By the late 1980s and early 1990s, however, oil prices had stabilized, natural gas prices had declined, and excess generating capacity in most regions of the country allowed utilities to buy capacity and energy at much lower prices than had been forecast a decade earlier. The utilities' actual avoided costs dropped lower than in the mid-1980s and were considerably lower than the levels required by the long-term contracts imposed by some State Commissions. Many utilities contend that PURPA has caused dramatic hikes in retail electric rates, and many groups along with these utilities now believe that new regulatory action must be taken to correct past misjudgments.[75]

Forecasters predict that future power generation will be dominated by natural gas. Reformers argue that, based on these forecasts, PURPA becomes irrelevant because natural gas-fired power generation is relatively inexpensive and the most environmentally benign of all the fossil fuels used in electric power generation. As mentioned earlier, some groups contend that PURPA is no longer necessary because its goals have already been achieved—i.e., cogeneration using improved turbine techniques and the use of renewable resources has not only gotten a foothold but has claimed a rather significant share of electric power production. Proponents of repeal further contend that PURPA's environmental and fuel diversification goals will be maintained by the workings of a free market while others are not so sure. Although they may agree that a free market can provide a solution to many of the industry's problems, they seriously question the wisdom

[74] For a discussion of the events that led to PURPA and how it affected the industry, refer to Chapter 4.

[75] Energy Information Administration, *Renewable Energy Annual 1995*, DOE / EIA-0603(95) (Washington, DC, December 1995), pp. xxvi-xxvii.

of relying on competition to continue the strides made in the use of renewables and cogeneration techniques. Energy conservation and diversification of generating fuels were mandated by Congress because of the growing dependence on foreign oil and the Nation's concerns about the energy crises of the 1970s. Those fears have faded with the passage of time, but it is argued that it is not out of the realm of possibilities that another crisis could occur. Indeed, some believe that it would be shortsighted and irresponsible to regard energy shortages as merely nightmares of the past and to gamble on the unlikelihood of a similar recurrence. They argue that the Nation cannot be without the ability to cope with such a situation in the future.

Even if dependence on foreign energy sources was not an issue, PURPA supporters stress that common sense dictates that energy be conserved and that electricity generation use more environmentally benign fuels in order to sustain a certain quality of life for future generations.[76] In addition, some believe that QF policy corrects a market failure—i.e., the price of fossil or nuclear energy is too low based on the costly damage it does to the environment and the fact that those who create the pollution do not pay for it. In this context, some argue that conservation, diversification of fuels, and the use of renewable resources that are not depletable and other fuels that lessen the problems of acid rain and greenhouse gases must continue to be supported.

In addition to PURPA's merits regarding the environment and fuel diversification, its supporters point out that QFs bring increased reliability while decreasing the need for large, costly plants. They contend that today's utilities have too much market power, which makes it necessary for PURPA to continue to give nonutilities a competitive advantage, and until every electricity generator is playing on a level field, PURPA's QF provisions are justified.

There are also those who believe that, while PURPA repeal might be warranted in a competitive electricity supply scenario, such a scenario has not been realized yet. Just as some PUHCA reformers are against immediate piecemeal and stand-alone action, some PURPA reformers believe that repeal should be included in a comprehensive restructuring bill. They argue that there is no need to push a stand-alone repeal bill through Congress when there is currently other proposed electricity competition legislation that will comprehensively address the restructuring and regulatory issues that warrant legislative action, including repeal of PURPA.

The Administration's Comprehensive Electricity Competition Proposal

The Administration released its revised version of the Comprehensive Electricity Competition Plan in April 1999. The 1999 Plan closely mirrors the Administration's 1998 proposal.[77] Both are built on the premise that a competitive electric energy market will lower prices, encourage innovation, and allow customers a choice in electric energy suppliers. The Administration's Plan also aims to promote a clean environment, increase the reliability of the national power supply grid, and to aid low-income consumers, rural communities, and Indian tribes.[78]

Several issues that were not adequately developed in the 1998 Plan have since been included in the 1999 Plan. These are:

- Improving prospects for competition in regions served by the Tennessee Valley Authority, the Bonneville Power Administration, and other Federal Power Marketing Administrations
- Encouraging the use of environmentally friendly and reliable technologies
- Enhancing consumer protection
- Enhancing the reliability of our electric system
- Providing support for Indian tribes and consumers in those areas
- Increasing environmental benefits
- Addressing the impact of competition on potentially affected electricity workers.

[76] This is related to the concept of "sustainable development," which refers to ways of social, economic, and political progress that meet the needs of the present without compromising the ability of future generations to meet their needs. Sustainable development points to ways that the economy can continue to develop without compromising the environment.
[77] U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 1998).
[78] Adopted from the fact sheet issued by the Department of Energy on the *Comprehensive Electricity Competition Plan* (April 15, 1999).

The Comprehensive Electricity Competition Plan:[79]

- Supports customer choice through a flexible mandate that would require each utility to permit all its retail customers to purchase power from the supplier of their choice by January 1, 2003. States or unregulated utilities could opt out if they find that consumers would be better served by an alternative policy or the current monopoly system. This approach strikes a balance between the need to spur competition and the tradition of determination of retail electricity policy by States.

- Endorses the principle that utilities should be able to recover prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated (including assistance for displaced workers). States and non-regulated utilities would continue to determine stranded cost recovery under State laws. The Plan grants FERC "backup" authority to establish a stranded cost recovery mechanism if the State lacks the authority to provide such recovery due to constitutional constraints or jurisdictional gaps.

- Stipulates critical consumer protection initiatives by: (1) requiring all electricity suppliers to publicly disclose information on price, terms, and conditions of their offerings; the type of generation source; and generation emission characteristics; (2) granting all consumers access to competitive retail service; (3) precluding possibilities of "slamming"[80] and "cramming;"[81] and (4) permitting customers to aggregate their loads.

- Repeals substantive requirements of PUHCA. Provides States and FERC with additional access to books and records of holding companies to assist regulatory authorities in guarding against inter-affiliate abuses.

- Establishes FERC's jurisdiction over mergers / consolidations of electric utility holding companies and generation-only companies, and directs FERC to examine the impact of mergers on the competitiveness of retail markets.

- Authorizes FERC to remedy market power in wholesale markets and further accords the Commission "back up" market power remedies, including ordering divestiture of assets in cases where States lack necessary authority to remedy retail market power.

- Recommends that the Federal Power Act (FPA) be amended to require FERC to approve the formation of and oversee an organization that prescribes and enforces mandatory reliability standards.

- Creates an Electricity Outage Investigation Board to investigate major electricity outages and report its findings to the Secretary of Energy.

- Recommends that the Secretary of Energy be permitted to convene joint Federal / State meetings to consider transmission capacity additions.

- Recommends amendments to the FPA to provide FERC with the authority to require transmitting utilities to turn over the operational control of their transmission facilities to an independent regional system operator (who should also have planning and reliability responsibility).

- Secures the future of renewable generation through the establishment of a Renewable Portfolio Standard (RPS) to require that 7.5 percent of annual electricity sales be generated from non-hydroelectric renewable sources by 2010. This requirement ends in 2015. The Plan repeals the "must buy" provisions of PURPA, but preserves existing contractual obligations.

- Encourages and supports continued funding of public benefit programs by creating a $3 billion Public Benefits Fund to provide matching funds for States for low income assistance, energy efficiency and renewables programs, consumer education, and the development and demonstration of emerging renewables technologies.

- With a view to promote renewables, recommends that consumers should be eligible for net metering with respect to very small renewable energy projects.

- Recommends that Indian tribes be assisted to participate in the new electricity markets and that an Office of Indian Energy Policy and Programs be established to evaluate various options in a changing market environment.

[79] Adopted from the fact sheet issued by the Department of Energy on the *Comprehensive Electricity Competition Plan* (April 15, 1999).
[80] Slamming is a term used to describe changing a customer's service provider without his or her permission.
[81] Cramming is a term used to describe the inclusion of charges on a customer's bill for services he or she never ordered, authorized, received, or used.

- Clarifies the authority of the Environmental Protection Agency to require a cost-effective interstate trading system for nitrogen oxide pollutant reductions necessary to attain and maintain the National Ambient Air Quality Standards for ozone.

- Ensures that Federal ownership of transmission facilities does not hinder competition by modifying the governing rules of the Tennessee Valley Authority and Federal Power Marketing Administrations.

- Aims to clarify Federal and State authority in several areas. It aims to provide FERC with the authority to order retail transmission, reinforces FERC's jurisdiction over unbundled retail transmission, and extends FERC's authority over municipals and cooperatives. The Plan exempts Alaska and Hawaii from the provisions of the Comprehensive Electricity Competition Act.

- Eliminates private-use restrictions currently imposed on facilities using tax-exempt funds subject to the requirement that tax-exempt financing not be used for generation and transmission facilities in the future.

- Addresses nuclear decommissioning costs and eliminates anti-trust review by the U.S. Nuclear Regulatory Commission.

Conclusion

This chapter has examined Federal-level restructuring actions taken by the U.S. Congress. Table 8 lists the bills that have been introduced into the current Congress that deal with one or more aspects of restructuring the electric power industry.[82] It is in chronological order (by date of introduction) and begins with the House of Representatives bills followed by the Senate bills. Appendix D provides a summary of each.[83] Further details about the status of the proposals and statements made by the committee chairmen, as well as the full text of the bills, can be accessed through the Library of Congress website at http://thomas.loc.gov. The following chapter discusses additional Federal-level initiatives—those taken by FERC concerning wholesale power markets and restructuring the U.S. transmission system. Subsequently, Chapter 8 analyzes State-level activities and Chapter 9 looks at investor-owned utility strategies, i.e., mergers, acquisitions, and divestitures.

[82] As of May 1, 2000, three of these bills are at the forefront of Congressional attention. They are H.R. 2944 (which was the first and only proposal to move out of the Subcommittee to the full Committee), S. 1047 (the Administration's proposal), and S. 2098 (Senator Murkowski's proposal).

[83] Bills that are not passed during the current Congress must be reintroduced in the next Congress. Of those which are reintroduced, some will be amended while others may remain the same.

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000

Bill	Purpose/Sponsor
H.R. 341 Environmental Priorities Act of 1999	Establishes a “Fund for Environmental Priorities” to be funded by a portion of the consumers’ savings resulting from retail electricity choice, and for other purposes. Introduced by Representative Robert Andrews (D-NJ) on January 19, 1999.
H.R. 667 The Power Bill	Clarifies State authority in matters involving retail wheeling, reciprocity, and recovery of stranded costs, eliminates mandatory purchase provisions contained within the Public Utility Regulatory Policies Act of 1978, repeals the Public Utility Holding Company Act of 1935, and for other purposes. Introduced by Representative Richard Burr (R-NC) on February 10, 1999.
H.R. 721 Bond Fairness and Protection Act of 1999	Amends the Internal Revenue Code by restricting tax-exempt bond financing by public power utilities, and for other purposes. Introduced by Representative J.D. Hayworth (R-AZ) on February 11, 1999.
H.R. 971 Electric Power Consumer Rate Relief Act of 1999	Amends the Public Utility Regulatory Policies Act of 1978 to allow State regulatory authorities to monitor rates charged by qualifying facilities and to determine whether the facilities meet FERC standards. Introduced by Representative James Walsh (R-NY) on March 3, 1999.
H.R. 1138 Ratepayer Protection Act	Repeals Section 210 of the Public Utility Regulatory Policies Act. Introduced by Representative Clifford Stearns (R-FL) on March 16, 1999.
H.R. 1253 A Bill to Amend the Internal Revenue Code of 1986	Amends the Internal Revenue Code to restrict the use of tax-exempt financing by governmentally owned electric utilities and to subject certain activities of such utilities to income tax. Introduced by Representative Phil English (R-PA) on March 24, 1999.
H.R. 1486 Power Marketing Administration Reform Act of 1999	Provides for a transition to market-based rates for power sold by the Federal Power Marketing Administrations and the Tennessee Valley Authority. Introduced by Representative Bob Franks (R-NJ) on April 20, 1999.
H.R. 1587 Electric Energy Empowerment Act of 1999	Amends the Federal Power Act to grant States the authority to oversee and implement restructuring of the electricity industry, repeals Section 210 of the Public Utility Regulatory Policies Act of 1978, repeals the Public Utility Holding Company Act of 1935, and for other purposes. Introduced by Representative Cliff Stearns (R-FL) on April 27, 1999.

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
H.R. 1828 Comprehensive Electricity Competition Act	Provides a comprehensive approach to restructuring the private and public electricity industry and includes provisions to amend or repeal the Public Utility Regulatory Policies Act of 1978, the Federal Power Act, the Public Utility Holding Company Act of 1935, and for other purposes. Introduced by Representative Thomas Bliley (R-VA) on May 17, 1999.
H.R. 2050 Electric Consumers' Power to Choose Act of 1999	Provides a comprehensive approach to electricity restructuring, aims to provide consumers with a reliable source of energy and a choice of electric providers, and for other purposes. Introduced by Representative Steve Largent (R-OK) on June 8, 1999.
H.R. 2363 The Public Utility Holding Company Act of 1999	Repeals the Public Utility Holding Company Act of 1935 and enacts the Public Utility Holding Company Act of 1999 to provide for continuing consumer protection by facilitating Federal and State commission access to relevant books and records of all companies in a holding company system. Introduced by Representative W.J.(Billy) Tauzin (R-LA) on June 25, 1999.
H.R. 2569 Fair Energy Competition Act of 1999	Directs FERC to prescribe stricter air quality regulations, establishes a National Electric System Public Benefits Board for public purpose programs funded by a capped wires charge assessed to each operator, creates a renewable energy portfolio, amends the Public Utility Regulatory Policies Act of 1978, and for other purposes. Introduced by Representative Frank Pallone, Jr. (D-NJ) on July 20, 1999.
H.R. 2602 National Electricity Interstate Transmission Reliability Act	Grants FERC jurisdiction over the creation and operation of an Electric Reliability Organization (ERO) and authorizes FERC to approve and enforce reliability standards for the bulk-power system. Introduced by Representative Albert Wynn (D-MD) on July 22, 1999.
H.R. 2645 Electricity Consumer, Worker, and Environmental Protection Act of 1999	Establishes consumer protection mechanisms, addresses stranded cost recovery, electric utility mergers, and standards for a renewable energy portfolio. Requires utilities to transfer certain assets to regulated counterparts or affiliates after deregulation of electricity sales. Introduced by Representative Dennis Kucinich (D-OH) on July 29, 1999.

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
H.R. 2756 Fair Competition in Tax-Exempt Financing Act of 1999	Amends the Internal Revenue Code of 1986 to prevent tax-exempt bonds from being used to finance public projects that will compete with private enterprise. Introduced by Representative Ralph Hall (D-TX) on September 15, 1999.
H.R. 2786 Interstate Transmission Act	Places unbundled transmission sold at retail under FERC jurisdiction and allows FERC to determine State or Federal jurisdiction for transmission and distribution facilities. Authorizes FERC to review pricing policies and activities of transmission service and allows for recovery of stranded costs. Introduced by Representative Thomas Sawyer (D-OH) on August 5, 1999.
H.R. 2944 Electricity Competition and Reliability Act of 1999	Provides a comprehensive approach to restructuring the electricity industry and includes provisions to amend or repeal the Public Utilities Regulatory Policies Act of 1978, the Federal Power Act, the Public Utility Holding Company Act of 1935, establish an electric reliability organization, and for other purposes. Introduced by Representative Joseph Barton (R-TX) on September 24, 1999.
H.R. 2947 Home Energy Generation Act	Removes barriers to net metering by amending the Federal Power Act and imposes standards for net metering and interconnection to the electric grid. Introduced by Representative Jay Inslee (D-WA) on September 24, 1999.
S.161 Power Marketing Administration Reform Act	Prescribes guidelines and sets operational requirements on the Federal Power Marketing Administrations and the Tennessee Valley Authority to assist as they transition to a competitive market, and prescribes specifics regarding use of revenue collected through market-based pricing. Introduced by Senator Daniel Moynihan (D-NY) on January 19, 1999.
S. 282 Transition to Competition in the Electric Industry Act	Repeals Section 210 of the Public Utilities Regulatory Policies Act of 1978 and allows for recovery of stranded costs. Introduced by Senators Connie Mack (R-FL) and Bob Graham (D-FL) on January 21, 1999.
S. 313 Public Utility Holding Company Act of 1999	Repeals the Public Utility Holding Company Act of 1935 and enacts the Public Utility Holding Company Act of 1999, and for other purposes. Introduced by Senator Richard Shelby (R-AL) on January 27, 1999.

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
S. 386 Bond Fairness and Protection Act of 1999	Amends the Internal Revenue Code by eliminating restrictions on public power utilities which impede their ability to provide open access transmission, and restricts the ability of public power utilities to use tax-exempt financing for construction of new facilities. Introduced by Senator Slade Gorton (R-WA) on February 6, 1999.
S. 516 Electric Utility Restructuring Empowerment and Competitiveness Act of 1999	Benefits consumers by promoting competition in the electric power industry, and for other purposes. Introduced by Senator Craig Thomas (R-WY) on March 3, 1999.
S. 1047 Comprehensive Electricity Competition Act [a]	Provides a comprehensive approach to electricity restructuring and includes provisions to amend or repeal the Public Utilities Regulatory Policies Act of 1978, the Federal Power Act, and the Public Utility Holding Act of 1935, and for other purposes. Introduced by Senator Frank Murkowski (R-AK) on May 13, 1999.
S. 1048 Comprehensive Electricity Competition Tax Act	Amends the Internal Revenue Code with respect to tax-exempt private activity bonds to declare that the determination whether any electric output facility bond issued before enactment of this Act is a private activity bond shall be made without regard to any specified permissible competitive action taken by the issuer. Introduced by Senator Frank H. Murkowski (R-AK) on May 13, 1999.
S. 1273 Federal Power Act Amendments of 1999	Amends the Federal Power Act, facilitates the transition to more competitive and efficient electric power markets, and for other purposes. Introduced by Senator Jeffrey Bingaman (D-NM) on June 24, 1999.
S. 1284 Electric Consumer Choice Act	Amends the Federal Power Act to include reciprocity provisions, recognizes the State's authority to regulate retail electric sales and the local distribution of electric energy, repeals the Public Utility Holding Company Act of 1935 and Section 210 of the Public Utilities Regulatory Policies Act of 1978. Introduced by Senator Don Nickles (R-OK) on June 24, 1999.
S. 1369 Clean Energy Act of 1999	Enhances the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, energy conservation and efficiency, and for other purposes. Introduced by Senator James Jeffords (R-VT) on July 14, 1999.
S. 1949 Clean Power Plant and Modernization Act of 1999	Sets emission standards for operating and future fossil fuel-fired generating plants, and for other purposes. Introduced by Senator Patrick Leahy (D-VT) on November 17, 1999.

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
S. 2071 Electric Reliability 2000 Act	Benefits electricity consumers by promoting the reliability of the bulk power system. Introduced by Senator Slade Gorton (R-WA) on February 10, 2000.
S. 2098 Electric Power Market Competition and Reliability Act	Facilitates the transition to a more competitive and efficient electric power market and ensures electric reliability. Introduced by Senator Frank Murkowski (R-AK) on February 24, 2000.

[a]This is the Administration's restructuring proposal.
Source: Library of Congress website at http://thomas.loc.gov/.

7. Wholesale Power Markets and Restructuring the U.S. Power Transmission System

Introduction

While congressional assent is necessary for many of the reforms to the electric power industry, Congress has granted the Federal Energy Regulatory Commission (FERC) authority to make regulations in a number of areas. The purpose of this chapter is twofold. First, it highlights FERC initiatives to promote competitive wholesale power markets over approximately the past 20 years, which have become progressively broader in scope in recent years. Second, it highlights FERC's initiatives in promoting an efficient and reliable power transmission system.[84] The two areas—promoting competitive wholesale power markets and an efficient power transmission system—are interrelated goals. Having fully competitive power markets depends on creating an efficient, well operating transmission system.

As mentioned in Chapter 3, the power transmission system is one of three major components of the electric power industry; the others are power generation and distribution. The transmission system provides the capability to move electrical power over long distances, producing significant benefits to electric utilities and to electricity customers. One benefit is that large efficient power plants can be built far from where the power is used, and the transmission system or systems can deliver power from those plants to many customers over a broad area at a relatively low cost. This capability was one of the reasons that utilities built large centralized power plants, which now provide most of the Nation's power generation capacity.

Another benefit of today's transmission system is that it provides wholesale electricity customers an opportunity to purchase less expensive power from alternative suppliers such as power marketers or independent power producers. This opportunity, which did not exist until the passage of the Energy Policy Act of 1992 (EPACT), and later expanded in 1996 by FERC's Order 888, is the foundation for creating competitive wholesale power markets.

As the electric power industry becomes more competitive, many of the changes taking place involve the regulation, operation, and control of the transmission system. FERC, the agency responsible for regulating interstate energy commerce and the transmission grid, is at the forefront of these changes. Its objective is to make the power generation sector more competitive by fostering wholesale power markets, and to make the Nation's transmission system more efficient.

FERC Promotes Wholesale Competition and Transmission Efficiency

FERC has long believed that competition in electric power generation could result in lower electricity prices and improved services for wholesale and retail electricity customers. Beginning approximately in the mid-1980s, FERC has issued numerous Orders, Policy Statements, or case rulings designed to promote competition in wholesale power markets and to improve operation of the transmission system. (Table 9 presents a chronological summary of these documents.) FERC's objectives center on five broad functions:

- Introducing market-based rates for wholesale power sales
- Providing nondiscriminatory access to the power transmission system
- Developing guidelines for recovery of stranded costs
- Promoting transparency of information about the bulk transmission system
- Promoting development of regional transmission organizations.

[84] The transmission system is an interconnected group of lines and equipment for the movement or transfer of electric energy between points of supply and points where it is transformed for delivery to customers or is delivered to other electric systems.

Table 9. Overview of the Federal Energy Regulatory Commission's Efforts Promoting Competition in the Electric Power Industry

Date	Description of FERC Efforts
1985-1991	Prior to the Energy Policy Act, FERC encouraged and approved the use of market-based rates representing one of FERC's initial efforts to make the industry more efficient. Between 1985 and mid-1991, FERC addressed 31 requests to sell wholesale electric power at market-based rates (Notice of Public Conference and Request for Comments on Electricity Issues, Docket No. PL91-1-000, April 1991).
July 1993	FERC issued a policy statement regarding Regional Transmission Groups (RTGs). The purpose of RTGs was to facilitate the provision of transmission services to potential users of the transmission system and to facilitate the resolution of disputes over provision of services. It was believed by FERC that RTGs would encourage negotiated agreements between transmission providers thereby avoiding the need for potentially time-consuming and expensive litigation before FERC (Policy Statement Regarding Regional Transmission Groups, RM93-3-000, July 30, 1993).
May 1994	FERC established general guidelines for comparable transmission access for third parties. Comparable access refers to the belief that owners of the transmission grid should offer third parties access to the grid on the same or comparable basis and under the same or comparable terms and conditions as the transmission owner's use of the system. Comparable access is one of the key ingredients of an open access transmission tariff specified in Order 888 (see below) (67FERC61, 168).
October 1994	FERC issued its Transmission Pricing Policy Statement. Prior to this policy statement, FERC had allowed only postage-stamp and contract path pricing of transmission services. In this policy statement, FERC recognized the need to encourage a variety of other pricing methods that may be more suitable for competitive wholesale power markets (Transmission Policy Statement, RM93-19-001, October 1994, Final Rule Order on reconsideration and clarifying the policy statement, May 22, 1995).
April 1996	FERC issued Order 888, requiring all public utilities that own, control, or operate transmission facilities to have on file an open access non-discriminatory transmission tariff. The Order also permits public utilities to seek recovery of stranded costs associated with providing open access (Order 888, Final Rule, RM95-8-000, and RM94-7-001, April 24, 1996).
April 1996	FERC issued Order 889 establishing the Open Access Same-Time Information System.
December 1996	FERC issued a Policy Statement (Order 592) amending its procedures to evaluate potential mergers between electric utilities. The procedures were designed to streamline the merger application process, and update FERC's evaluation of the merger to consider the merger's effect on competition, its effect on rates, and its effect on regulation.
January 1997 - December 1998	FERC conditionally approved five Independent System Operators (ISOs)—California ISO, ISO-New England, New York ISO, Pennsylvania, New Jersey, Maryland (PJM) ISO (official name is PJM Interconnection), and the Midwest ISO.
December 1999	FERC issued Order 2000 asking all transmission-owning utilities, including non-public utilities, to place their transmission facilities under the control of an appropriate regional transmission organization (RTO). So that utilities could comply with this request, the characteristics and minimum functions of an appropriate RTO were defined in the Order (Order 2000, Final Rule, RM99-2-000, December 20, 1999).

Introducing Market-Based Rates for Wholesale Power Sales

In a regulated environment, wholesale and retail electricity power prices are calculated based on a utility's embedded costs plus a negotiated rate of return on their investments. Because this method ensures that the utility will cover its costs of operation, this method does not have appropriate incentives to motivate a utility to fully evaluate all the risks of an investment. If a utility invests in what turns out to be an uneconomical project, it can still add the costs of the investment to the price it charges for electricity. Thus, the risks and economic consequences of a poor investment are passed to the electricity customer. Another limitation is that the cost-based pricing concept is the antithesis of the objective of promoting competitive wholesale power markets.

To overcome the limitations of cost-based pricing, in the mid-1980s FERC considered 31 applications to use market-based pricing for wholesale transactions, although only a few applications were approved. However, by the mid-1990s, FERC had approved the use of market-based rates for more than 100 power suppliers, and substantial growth in their use had begun.

Currently, 866 companies are eligible to sell wholesale power at market-based rates, including 389 independent power producers, 271 affiliated power marketers and producers, and 206 investor-owned utilities (IOUs) and other utilities (Table 10). Affiliated companies must comply with standards of conduct designed to eliminate abuses and reciprocal dealing between the public utility and its affiliated power marketer.[85]

Table 10. Companies Eligible to Sell Wholesale Power at Market-Based Rates, as of May 1, 2000

Type of Company	Number of Companies
Independent Power Marketers	389
Affiliated Power Marketers	117
Affiliated Power Producers	154
Investor-Owned Utilities	99
Other Utilities	107
Total	**866**

Source: Federal Energy Regulatory Commission, online at www.ferc.fed.us/electric/PwrMkt/PM_LIST.htm (May 2000).

The use of market-based prices started with bilateral transactions, where buyers and sellers negotiated a price. Since then, a few centralized power markets have been created where a power supplier sells through a power exchange, and wholesale electricity prices are based on the market conditions at the exchange. Centralized power markets have begun in New England; New York; Pennsylvania, New Jersey, Maryland (PJM) region; and California. More are likely to open during the coming years. Without blanket approval to sell power at market-based rates, these competitive centralized markets could not exist.

Providing Nondiscriminatory Access to the Transmission System

Historically, many vertically integrated utilities did not allow independent power suppliers to use their transmission systems. If they were ordered to provide access, the integrated utilities would favor power from their own plants over the independent supplier when the transmission lines became congested. In some instances, the utility would withhold certain types of important transmission services. These practices stymied the growth of competitive power generation markets because they limited the extent to which independent power suppliers could provide service to electricity customers.

EPACT's passage gave FERC broad authority to order transmission-owning utilities to wheel power for wholesale power transactions, and it helped to relieve some of the barriers to using the transmission system. Wheeling occurs when a transmission-owning utility allows another utility or independent power producer to move (or wheel) power over its transmission lines. Although FERC's wheeling authority facilitated creation of competitive wholesale electricity markets, wheeling requests were evaluated on a case-by-case basis, which was sometimes slow and cumbersome. Also, disparities still persisted in the comprehensiveness and quality of transmission services provided by transmission owners to other users. To address disparities in service, in 1994 FERC established a "comparability standard" stating that transmission-owning utilities should offer other transmission users access to their transmission systems

[85] D.F. Santa, "Analytical Flaws and Practical Pitfalls: Reconsidering FERC's Merchant Affiliate Rules," *The Electricity Journal*, Vol. 11, No. 9 (November 1998).

on the same basis and under the same conditions as they use the transmission systems to service their own electricity customers. FERC also applied the comparability standard case-by-case; when a utility requested approval for market-based rates or approval to merge with another utility, FERC would specify that the utility must incorporate the comparability standard into its transmission tariff as a condition for approval.

Even with more wheeling authority and implementation of the comparability standard on a case-by-case basis, open non-discriminatory transmission access still did not exist universally. In April 1996 FERC took action to correct the lack of universal access by issuing Order 888. At that time, Order 888 was considered the most far-reaching and ambitious project undertaken by FERC to eliminate deterrents to competition in the electric power industry. Order 888 had two basic goals: (1) to eliminate anti-competitive practices and undue discrimination in transmission services through a universally applied open access transmission tariff, and (2) to ensure the recovery of stranded costs a utility might accrue in the transition to competitive markets.

With respect to the first goal, FERC imposed a blanket requirement that all transmission-owning utilities under its jurisdiction must file an open access transmission tariff specifying the terms and conditions for using their transmission systems. The comparability standard was one of the required conditions of the transmission tariff. One significant advantage of a universal transmission tariff was that it eliminated FERC's time-consuming case-by-case evaluation of wheeling requests. Instead, rights, terms, and conditions to wheel power were predefined in the tariff and a company could respond immediately to opportunities in short-term markets that previously were not available to them in a timely manner. Access to the transmission system in a timely manner is essential for a competitive short-term power market to function properly.

Another equally important component of Order 888 was the requirement for transmission owners to functionally unbundle their activities. Functional unbundling required the transmission owner to take transmission service under the same tariff as other transmission users (comparability standard); to separate rates for wholesale generation, transmission, and ancillary services; and to rely on the same electronic information network that its transmission customers rely on to obtain information about prices and available capacity of the transmission system. Essentially, the idea of functional unbundling was to avoid favoritism and discriminatory practices within a vertically integrated utility by separating its transmission services functions from other business activities in the company.

Order 888 covered other transmission tariff issues such as pricing of transmission services, the application of market-based rates for power sold from new capacity, and other items. (Table 11 provides a summary of the major provisions of Order 888 with respect to open transmission access.) Since issuance of Order 888, all utilities have filed their open access tariffs, and Order 888 is now history. In retrospect, Order 888 represented FERC's first broad sweeping effort to eliminate discriminatory and unfair practices in the management and control of the transmission system.

Developing Guidelines for Recovery of Stranded Costs

The second goal of Order 888 was to ensure that electric utilities are able to recover their sunk costs in a competitive industry. These sunk costs are called stranded costs, or transition costs, and they represent a utility's capital investments that are unrecoverable because of the transition to competition. The rationale for allowing stranded cost recovery is that utilities have invested billions of dollars in facilities under a regulatory regime that allowed cost recovery of all prudent investments. To gain support and cooperation for a successful transition to a competitive industry, and to be consistent with the past decisions, FERC believed it was critical that utilities recover these costs. At the same time, FERC recognized that recovery of stranded costs may delay some of the benefits of competitive power markets.

FERC's Order 888 spelled out under what general conditions a utility is entitled to recover its stranded costs and from whom. As far as entitlements, Order 888 specified that cost recovery at the wholesale level is limited to situations where there is a link between the use of FERC's required open access transmission tariff and the loss of wholesale power customers. FERC went further to specify that recovery of wholesale stranded costs should be assigned to the departing customer. At the retail level, FERC determined that States should have primary jurisdiction over cost recovery resulting from retail competition, although it would entertain requests to recover costs resulting from retail competition when a State does not have the authority.

FERC's concerns for the recovery of wholesale stranded costs may have been overestimated. Since Order 888 was issued, FERC has on record seven stranded costs cases. Moreover, as of April 2000, it had not received a filing for wholesale stranded cost recovery in more than a year

Table 11. Major Provisions of FERC Order 888 on Open Access

Functional Unbundling

A utility's uses of its own transmission system for the purpose of engaging in wholesale sales and purchases must be separated from other activities. Corporate unbundling is not required.

- Utilities must take transmission services (including ancillary services) under the same tariff of general applicability as do others.
- Utilities must state separate rates for wholesale generation, transmission, and ancillary services.
- Utilities must rely upon the same electronic information network that its transmission customers rely upon to obtain transmission information.

Nondiscriminatory Open Access Tariff Requirement

By July 9, 1996, jurisdictional utilities that own or control transmission must have filed a single open access tariff that offers both network, load-based services and point-to-point, contract-based services, including ancillary services, to eligible customers comparable to the service they provide themselves at the wholesale level. The rule provides a single *pro forma* tariff that sets forth minimum conditions for both network and point-to-point services and nonprice terms and conditions for providing those services and ancillary services.

Reciprocity

Transmission customers of jurisdictional utilities who take service under the open access tariff and who own, control, or operate transmission facilities must, in turn, provide open access service to the transmitting utility. This includes municipally owned entities and RUS cooperatives.

Services to be Provided

A public utility must offer transmission services that it is reasonably capable of providing, not just those services that it currently provides to itself and others.

Six ancillary services must be included in the open access tariff:

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation sources
3. Regulation and frequency response
4. Energy imbalance
5. Operating reserve—spinning reserve
6. Operating reserve—supplemental reserve.

The transmission customer must purchase the first two services from the transmission provider.

Pools and Holding Companies

Jurisdictional utilities who are members of tight or loose power pools must file either an individual *pro forma* tariff or a joint pool-wide *pro forma* tariff by July 9, 1996. They are not required to take service for pool transactions under that tariff, but are required to file a joint pool-wide tariff no later than December 31, 1996, and begin to take service under that tariff for all pool transactions by that same date. By that date, they must also restructure their ongoing operations and open membership to nonutilities.

Public utility holding companies not subject to tight or loose pool requirements are required to file a single system-wide *pro forma* tariff permitting transmission service across the entire holding company by July 9, 1996.

All bilateral economy energy coordination contracts executed before the effective date of this rule must be modified to require unbundling of any economy energy transaction occurring after December 31, 1996.

Pricing

The rule does not prescribe rates for network, point-to-point, or ancillary services. Instead, utilities may charge current rates or apply for new transmission rates. Utilities can propose to recover opportunity costs and expansion costs. Crediting for customers' transmission facilities will be permitted on a case-by-case basis. Proposed pricing must conform with FERC's Transmission Pricing Policy Statement.

Contract Reform

The rule does not void any existing requirements contracts. The functional unbundling requirement applies only to transmission services under new requirements contracts, new coordination contracts, and new transactions under existing coordination contracts.

Parties to requirements contracts executed on or before July 11, 1994, may seek modification of such contracts on a case-by-case basis, even if they contain a Mobile-Sierra clause. FERC, however, does not take contract modification lightly and parties seeking to modify contracts will have a heavy burden to demonstrate the need for it.

Customer Eligibility

Any entity engaged in wholesale purchases or sales of energy or retail purchases is an eligible customer.

Market-Based Rates

Utilities seeking market-based rates for sale of electricity at wholesale from new capacity are no longer required to demonstrate lack of market power in generation. New capacity is that for which construction has commenced on or after the effective date of this rule. For existing generation, FERC will continue its case-by-case approach that includes an analysis of generation market power in first- and second-tier markets.

Source: Adapted from "FERC Finalizes Electric Industry Restructuring Rule," *Public Utility Topics* (Philadelphia, PA: Coopers & Lybrand, L.L.P., June/July 1996), No. 96-2, p. 4.

and a half.[86] The overwhelming majority of stranded costs awards have been in States that have implemented retail competition. Chapter 8 contains a discussion of stranded costs resulting from States introducing retail competition.

Promoting Transparency of Information About the Bulk Power Transmission System

To follow through with non-discriminatory access to the transmission system, timely and accurate day-to-day information about transmission must be unrestricted and public to all transmission users. To implement this concept, in 1996 FERC issued Order 889 requiring all IOUs to participate in the Open Access Same-Time Information System (OASIS).

The OASIS is an interactive Internet-based database containing information on available transmission capacity, capacity reservations, ancillary services, and transmission prices. The underlying idea of the OASIS is to create an interactive computerized market for transmission-related products and services which is accessible by all qualified users of the transmission system. In that role, the OASIS facilitates the functioning of competitive power markets.

The OASIS became operational in January 1997. Currently, 23 OASIS nodes are on the Internet, and approximately 166 transmission owners participate by providing information about their transmission facilities. Initially the OASIS had operational problems traceable to a lack of common data elements and business practices. This condition made it difficult to compare data between nodes, and to conduct business over multiple nodes. Recently, OASIS developers have adopted a common set of Business Practice Standards to improve the interaction between transmissions providers and customers over the OASIS.[87] Implementation of these standards should move the OASIS further along in becoming a useful tool in support of a competitive industry.

Promoting Development of Regional Transmission Organizations

Promoting regional transmission organizations (RTOs) is the last of FERC's major objectives discussed in this chapter. It arguably can be called FERC's most significant and, to some extent, most tumultuous activity undertaken in its effort to create a more competitive and efficient industry.

The concept of regional organizations in the electric power industry has existed for some time. Many regional entities have been created for planning, coordination, or system reliability functions. The most visible are the 10 Regional Reliability Councils that develop standards and procedures to maintain the reliability of the Nation's power system. Some industry observers have noted that perhaps there are too many regional entities, and that regional decision-making authority and responsibility sometimes becomes blurred.

RTOs refer to the idea of organizing the operation, control, and possible ownership of the transmission grid into independent companies or organizations; the process of forming RTOs is also referred to as grid regionalization.[88] Regional control of the transmission grid has many coordination and efficiency advantages over the current balkanized configuration where each vertically integrated utility operates and controls its own transmission facilities.

FERC's effort to foster grid regionalization consists of three progressively ambitious initiatives. In 1993 FERC issued a policy statement recommending that transmission owners, transmission customers, and other interested parties form regional transmission groups (RTGs) to coordinate transmission planning and expansion on a regional and inter-regional basis (Table 9). A few RTGs were established, but their role has been limited. Although effective for planning purposes, these organizations were usually not vested with appropriate decision-making authority needed to address transmission issues affecting an entire region.

In its next initiative, FERC used a stronger and more ambitious approach to grid regionalization. In Order 888, FERC encouraged the formation of independent system operators (ISOs), whereby utilities would transfer operating control of their transmission facilities to the ISO. Ownership of the facilities would remain with the utility. Utility participation in an ISO was voluntary.

[86] Personal conversation with the Federal Energy Regulatory Commission, April 3, 2000.
[87] Federal Energy Regulatory Commission, "Open Access Same-Time Information System and Standards of Conduct–Order 638," (February 25, 2000).
[88] Regional Transmission Organizations (RTOs) have also been called power pools, regional transmission groups (RTGs), and independent system operators (ISOs). They are all similar in that they represent a grouping of transmission facilities owned by different electric utilities to achieve common objectives. Their missions, scope of responsibilities, and objectives, however, were different.

By encouraging ISO formation, FERC underscored its belief in the importance of unbundling power generation and marketing from operation and control of the transmission grid. An ISO with no economic interest in marketing and selling power could administer fairly the open access transmission tariff and eliminate discriminatory practices, and at the same time achieve the efficiency benefits from regional control of the grid.[89] Since Order 888 was issued, six ISOs have been formed and five of them are now operating. (The status of these ISOs is discussed later.)

Remaining Impediments to Competitive Power Markets After Order 888

Even with five ISOs operating and open access transmission tariffs in place, the development of wholesale power markets across the nation has been slow, and obstacles to competition still remain. Three major obstacles have been mentioned. First, since Order 888 was issued the Commission has received many complaints of transmission owners discriminating against independent power companies. Further, the Commission noted that an increase in the number of market participants and transactions in wholesale markets has made discriminatory behavior with regard to transmission access more subtle and more difficult to identify.[90] Second, the Commission observed that electric utilities' implementation of functional unbundling has not produced sufficient separation between operating the transmission system and marketing and selling power, and that this lack of separation contributes to discriminatory behavior. Third, grid regionalization through ISOs has occurred in some areas of the country, but was not implemented in other areas. Although creation of an ISO was voluntary, expectations were that more regions would seek to realize the benefits of grid regionalization and would participate in forming ISOs.

In addition to these obstacles, an increase in market participants and trading over the past few years, and changes to electricity trading patterns has made system reliability more difficult to maintain which impedes creating fully competitive power markets. The North American Electric Reliability Council (NERC) reported that, "[in recent years] the adequacy of the bulk power transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions."[91] This view is supported by a U.S. Department of Energy Task Force noting that "there is a critical need to be sure that reliability is not taken for granted as the industry restructures, and thus does not fall through the cracks."[92]

Not only has maintaining reliability become more difficult, other obstacles to competitive markets have emerged. Transmission congestion has increased, but current procedures for relieving congestion are antiquated and sometimes unfair. As FERC points out, "current transmission loading relief (TLR) procedures [for relieving congestion] are cumbersome, inefficient, and disruptive to power markets because they rely exclusively on physical measures of [electricity] flows with no attempt to assess the relative costs and benefits of alternative congestion management techniques." Another problem is that planning for transmission expansion is more difficult than in the past because of more uncertainty in the industry. Responsibilities for transmission expansion are not always clear, the motivation for construction of new facilities is changing, and cost recovery after construction may be more risky than in the past. Finally, the current method of transmission pricing is antiquated given the new competitive environment. In most of the United States, the transmission customer pays separate additive access charges every time the power crosses the boundary of a transmission owner. This practice is referred to as pancaked pricing, which has the effect of raising the cost of transmission and reducing the geographic size of competitive power markets.

Order 2000 and Grid Regionalization

FERC's third initiative to grid regionalization, which is currently being implemented, is perhaps its most ambitious effort. In December 1999, FERC issued Order 2000, calling for the voluntary creation of RTOs throughout the United States. FERC had noted that all of the Nation's transmission systems should be brought under regional control and perhaps regional ownership in order to eliminate the remaining discriminatory practices, meet the increasing demands placed on the

[89] The intent of FERC's functional unbundling requirement, specified in Order 888 and discussed above, was to accomplish the same thing without the need for separate organizations.
[90] Federal Energy Regulatory Commission, "Notice of Proposed Rulemaking , Regional Transmission Organization," RM99-2-000 (May 13, 1999).
[91] North American Electric Reliability Council, "Reliability Assessment 1998-2007" (September 1998).
[92] Secretary of Energy Advisory Board's (SEAB) Task Force on Electric System Reliability, "Maintaining Reliability in a Competitive U.S. Electric Industry" (September 29, 1998).

transmission system, and achieve fully competitive wholesale power markets. If FERC's implementation of Order 2000 is successful, the transmission system will go from a system owned and controlled mostly by vertically integrated electric utilities to a system owned and/or controlled by a few, but uncertain number of, unaffiliated RTOs.

With this formidable undertaking, the Commission again believes a voluntary approach will be successful because (1) many vertically integrated utilities recognize the benefits of an RTO, (2) Order 2000 provides clear rules and guidance for utilities to follow in forming an RTO, (3) to facilitate cooperation, the Commission established a collaborative process for RTO development, and (4) Order 2000 provides ratemaking incentives for companies who assume the risks of a transition to a new corporate structure. (Table 12 contains a summary of the major components of Order 2000.)

Potential Benefits of Regional Transmission Organizations Through Order 2000

By eliminating the balkanized control of the transmission grid, regionalization has the potential to increase significantly the overall operating efficiency of the industry system. Many industry analysts believe that combining the control of individual transmission systems under one regional organization with a wide regional scope can lead to improvements in transmission pricing, improved management of congestion, improved information relevant to promoting competition in power markets, better management of parallel path flow problems, improved reliability management, and as noted above, the elimination of remaining discriminatory practices concerning access to the transmission system services. The term potential is a key word because regionalized control of the Nation's transmission grid, as proposed in Order 2000, is a new and unproven concept. These potential benefits, some of which were alluded to in the above discussion, are covered below in more detail.

Eliminate remaining opportunities for discriminatory transmission practices: As organizations completely independent from power production and sales, RTOs will sever the economic incentives between power marketing and control of the transmission system. Without the economic incentive, the reasons for discriminatory practices should be eliminated. Functional unbundling required in Order 888 did not eliminate economic incentives, and was not completely effective in eliminating discriminatory practices.

Improve calculations of available transmission capacity: Available transmission capacity (ATC) is a measure of the amount of transmission capacity that is available to transmit power over the grid at a particular time. Market participants use this information to make short-term decisions to purchase or sell power. ATC is difficult to calculate due to constantly changing conditions and the complexity of the electrical network. The difficulty is compounded in a balkanized network where each utility calculates its own ATC. An RTO with regional scope will have better information on conditions of the network than an individual utility; with better information, more accurate estimates of ATC will be available to transmission users. Also, FERC has pointed out that many complaints have been filed claiming that transmission providers are calculating ATC to favor their own generators, which is a form of discrimination. An independent RTO will eliminate this behavior.

Improve management of parallel path flow and system reliability: The interconnection of the transmission grid makes management a difficult and challenging task. One of the biggest problems is managing parallel path flow (also called loop flow). Parallel path flow refers to the fact that electricity flows across an electrical path between source and destination according to the laws of physics, meaning that some power may flow over the lines of adjoining transmission systems inadvertently affecting the ability of the other region to move power. This cross-over can create compensation disputes among the affected transmission owners. It also impacts system reliability if a parallel path flow overloads a transmission line and decisions must be made to reduce (curtail) output from a particular generator or in a particular area. An RTO with access to regionwide information on transmission network conditions, with regionwide power scheduling authority, and with more efficient pricing of congestion can better manage parallel path flows and reduce the incidence of power curtailment.

Improve transmission pricing methods: Pricing of transmission services is one of the most important issues in restructuring the Nation's transmission system. Historically, FERC has based its approach to transmission prices on the rolled-in average historic costs of the transmitting utility. This method was largely developed for requirements service where the wholesale customer's load was dispersed throughout the utility's service territory and integrated generation and transmission facilities are used. The result has been a "postage stamp" rate. Postage stamp rates have important limitations, particularly in providing price signals to transmission

Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000 Final Rule Establishing Regional Transmission Organizations

Filing Requirements and Deadlines

1. Each public utility that owns, operates, or controls interstate transmission facilities (except those already participating in an approved regional transmission entity) must file by October 15, 2000, a proposal to participate in a regional transmission organization (RTO) that will be operational by December 15, 2001, or they must file, by the same date, a description of efforts to participate in an RTO, obstacles to participation, and plans and a timetable for future efforts.

2. Each public utility that is a member of an existing transmission entity that conforms with the 11 ISO principles contained in Order 888 must file by January 15, 2001, a description that explains the extent to which the transmission entity in which it participates meets the minimum characteristics and functions of an RTO, and how it proposes to modify the entity to become an RTO, or a description of efforts, obstacles, and plans to conform to an RTO's minimum characteristics and functions.

3. All RTOs will implement their minimum functions according to the following schedule:

- Congestion management function by December 15, 2002
- Parallel path flow coordination function by December 15, 2004
- Transmission planning and expansion function by December 15, 2004
- Other minimum functions will be implemented by startup.

Minimum Characteristics of a Regional Transmission Organization

1. Independence: The RTO must be independent of market participants. Independence can be achieved by meeting three conditions: (1) the RTO, its employees, and any non-stakeholder director must not have any financial interest in any market participants, (2) the RTO must have a decision-making process independent of control by any market participant, and (3) the RTO must have exclusive authority under Section 205 of the Federal Power Act to file changes to its transmission tariff.

2. Scope and Regional Configuration: The RTO's region must be of sufficient scope and configuration to perform effectively its required function and to support efficient and nondiscriminatory power markets. FERC will evaluate the configuration or boundaries of the RTO according to the extent it meets nine criteria:

- Facilitates performing essential RTO functions
- Encompasses one contiguous geographic area
- Encompasses a highly interconnected portion of the grid
- Deters the exercise of market power
- Recognizes existing trading patterns
- Takes into account existing regional boundaries (e.g., NERC regions)
- Encompasses existing regional transmission entities
- Encompasses existing control areas
- Takes into account international boundaries.

3. Operational Authority: The RTO must have operational authority for all transmission facilities under its control, and it also must be the security coordinator for the region. The security coordinator ensures the real-time operating reliability of the power systems.

4. Short-Term Reliability: The RTO must have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. Short-term is intended to include all time periods necessary for the RTO to satisfy its reliability responsibilities up to the planning horizon.

Minimum Functions of a Regional Transmission Organization

1. Tariff Administration and Design: The RTO will be the sole administrator of its own tariff and, therefore, it will be the sole decision-making authority on provision of transmission service including the decision to establish new interconnections.

2. Congestion Management: The RTO will ensure the development of market mechanisms to manage transmission congestion. These mechanisms should provide price signals to transmission customers regarding the consequences of their transmission usage decisions.

Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000 Final Rule Establishing Regional Transmission Organizations (Continued)

3. Parallel Path Flow: The RTO must implement procedures within 3 years of start-up to address the problems associated with interregional parallel path flow and implement procedures immediately for regional parallel path flow. Parallel path flow refers to the fact that electricity flows over transmission lines according to the laws of physics. Because of these laws, the power generated in one region may flow over the transmission lines of another region, inadvertently affecting the ability of the other region to move power.

4. Ancillary Services: The RTO must serve as the provider of last resort for all ancillary services as required in Order 888. The RTO should promote creation of competitive markets for procurement of these services.

5. Open Access Same-Time Information System (OASIS) and Capability Calculations: The RTO should act as a single OASIS node. The data elements of total transmission capability and available transmission capability, which are stored on the OASIS and used by potential transmission customers, will be calculated by the RTO, or if provided by the transmission owner, verified by the RTO.

6. Market Monitoring: The RTO will submit to FERC a market monitoring plan that (1) ensures that there is objective information about the markets, (2) contains procedures for proposing efficiency improvements, market flaws, and market power, and (3) contains procedures to evaluate the behavior of market participants.

7. Planning and Expansion: The RTO must develop a planning and expansion proposal that (1) encourages market-motivated operating and investment actions for preventing and relieving congestion, (2) accommodates efforts by State regulatory commissions to create multi-state agreements to review and approve new transmission facilities and coordinates with existing regional transmission groups, and (3) files a plan with milestones showing that the RTO will meet its planning and expansion requirements no later than 3 years after start-up.

8. Interregional Coordination: The RTO will develop mechanisms to ensure the integration of reliability practices within an interconnection and market interface practices among regions.

Open Architecture

Open architecture refers to the idea that RTOs should be designed so that improvements in their structure, operating rules, and other activities can evolve over time.

Policy for an RTO's Transmission Rates

FERC believes that effective transmission rates are essential in promoting economic efficiency in the generation and transmission sectors, and are an important factor to the success of the RTO as a stand-alone transmission business. FERC has approval responsibility for an RTO's transmission rate schedule. According to FERC policy, effective transmission rates will address the following issues:

1. Eliminate Pancake Pricing: Pancake pricing occurs when a transmission customer is charged separate access charges for each utility service territory crossed by the transmission customer's power transaction. Pancaking increases the price of electricity and it discourages competition in the generation sector. By combining transmission systems under one RTO, a wider area served by a single rate can be designed.

2. Reciprocal Waiving of Access Charges Between RTOs: FERC encourages the RTOs to waive transmission access charges for transactions that cross RTO borders. This increases the size of the competitive trading area beyond the RTO border.

3. Uniform Access Charges: FERC encouraged that an RTO establish one uniform access charge for all transmission customers. However, they recognized that this approach may result in cost shifting (i.e., low-cost transmission providers would see a rate increase, and high cost providers a rate decrease). As a temporary solution, FERC will allow a single rate, but that rate will vary based on where the customer is located.

4. Congestion Pricing: Congestion pricing is closely related to congestion management in that effective pricing of congestion problems provides the appropriate price signals to build additional transmission lines or power generation plants in order to eliminate congestion.

Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000 Final Rule Establishing Regional Transmission Organizations (Continued)

5. Service to Transmission-Owning Utilities that do not Participate in an RTO: FERC intends to permit an RTO to propose rates, terms, and conditions of transmission service that recognize the participatory status of transmission customers. In other words, a transmission customer who is also a transmission provider in the region that chose not to join the RTO, will have a different transmission tariff than other customers.

6. Performance-Based Regulation: Performance-based regulation (PBR) represents the concept of offering financial incentives to lower rates or costs. Under PBR, good performance can be rewarded with higher profits and poor performance can be penalized in some manner. As an alternative to cost-based regulation, FERC encourages the RTO to develop PBR proposals, although submission of a proposal is voluntary.

7. Other RTO Transmission Rate Reforms: To encourage investment in transmission facilities and efficiency in operation, FERC indicated that it would consider other innovative transmission pricing proposals such as a higher return on equity than previously allowed, levelized rates, or accelerated depreciation and incremental pricing for new transmission investments.

8. Additional Ratemaking Issues: This section of Order 2000 contained a wide range of comments on ratemaking issues not specifically addressed in the notice of proposed rulemakiing. These comments cover issues ranging from alternative ratemaking methods to issues dealing with how to incorporate incentives to promote environmentally benign resources.

9. Filing Procedures for Innovative Rate Proposals: FERC will evaluate innovative rate proposals based on how the proposed rate treatment would help achieve the goals of an RTO. Rate moratoria or returns on equity that do not vary according to the RTO capital structure may not be included in the RTO's rate structure after January 1, 2005.

Other Issues

In Order 2000, FERC identified nine issues, other than the ones discussed above, which may have an impact on the structure, completeness, regulation, and design of RTOs.

1. Public Power and Cooperative Participation in RTOs: FERC expects public power entities to participate in the formation of RTOs, but it is aware public power entities face several obstacles. The Internal Revenue Service Codes may prevent facilities financed by tax-exempt debt from wheeling privately owned power, or they may prevent transfer of operational control of transmission facilities financed by tax-exempt debt to a for-profit transmission company. State and local government laws may prevent public power entities from participating in RTOs. The lack of participation of public power entities may negate some of the effectiveness and expected benefits of RTOs.

2. Participation by Canadian and Mexican Entities: FERC opined that Mexican and Canadian participation in an RTO would be beneficial.

3. Existing Transmission Contracts: FERC indicated that it will examine, case-by-case, how to handle existing contractual arrangements when forming an RTO. For example, one issue may involve how to handle pancaked rates in existing contracts for others when transmission-owning utilities design a non-pancaked rate for their own transactions.

4. Power Exchanges: FERC will leave it to each region to determine a need for a power exchange, and if the RTO should operate the exchange should there be a need.

5. Effects on Retail Markets and Retail Access: FERC opined that formation of an RTO will not affect the ability of States to implement retail markets and competition. In Order 2000, FERC noted that experience with the independent system operators (ISOs) indicates that an RTO could be a benefit to States that are implementing retail competition.

6. Effects on States with Low-Cost Generation: Some States are concerned that an RTO would result in local utilities selling their low-cost power to other States. FERC asserted that an RTO will provide access to future low-cost generation plants and that new low-cost generation plants will be attracted to regions with an RTO because of dependable and nondiscriminatory access to the transmission system.

7. States' Role With Regard to RTOs: FERC believes that States have an important role to play, but they chose not to specify what role in Order 2000.

Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000 Final Rule Establishing Regional Transmission Organizations (Continued)

8. Accounting Issues: FERC will require that RTOs conform to the Uniform System of Accounts, but they also indicated that changes in the industry require them to re-examine existing accounting and related reporting requirements.

9. Market Design Lessons: FERC envisions that bid-based markets for wholesale electric power will be a central feature in many RTO proposals. Although bid-based markets for electric power do not now represent the dominant method for buying and selling electricity, this method is expected to grow. In Order 2000, FERC summarizes lessons learned from its analysis and approval of bid-based markets for four independent system operators. As these and other power markets mature, additional information on how to design and operate power markets will develop.

- **Multiple Product Markets:** Efficiency of a multi-product market operating in the same time period is maximized when arbitrage opportunities reflected in the bids are exhausted. That is, it is efficient when, after the RTO's market has cleared, no market participant would have preferred to be in another of the RTO's markets.
- **Physical Feasibility:** Transaction in the market should be physically feasible.
- **Access to Real-Time Balancing Market:** Real-time balancing refers to the moment-to-moment matching of loads and generation on a system-wide basis. A real-time balancing market should be available to all grid users for purposes of settling their individual imbalances.
- **Market Participation:** Markets are more efficient with a broad participation.
- **Demand-Side Bidding:** The current wholesale power markets do not offer customer demand-side bidding, only power suppliers bid into the markets. However, demand-side bidding, to the extent it is practical, is desirable to make electricity supply and prices more responsive to competitive markets.
- **Bidding Rules:** The market should allow generators to make bids that approximate their costs.
- **Transaction Costs and Risks:** Transaction costs should be low and participation in the market should involve no unnecessary risk.
- **Price Recalculations:** Market clearing prices should minimize electricity price recalculations.
- **Multi-Settlement Markets:** Multi-settlement markets may involve a day-ahead market and a real-time market. If the day-ahead market bids are needed for reliability, these bids need to be physically binding and may be subject to penalties for failing to adhere to the bid.
- **Preventing Abusive Market Power:** FERC highlights three items which will help to lessen the potential for market power: (1) have fewer restrictions on importing power into the region, (2) have less segmentation of geographic markets for the same product, and (3) stop allowing market participants to change bids before they complete the financial settlement. Bid changing can be used as signaling to facilitate collusive behavior.
- **Market Information and Marketing Monitoring:** Market clearing prices and quantities should be transparent so that market participants can assess the market and plan their business efficiently.
- **Prices and Cost Averaging:** Transmission and congestion prices based on average costs may distort power production, power consumption, and investment decisions. More innovative pricing methods are needed.

Collaborative Process: FERC asserted its commitment to hold regional workshops to assist in the voluntary formation of RTOs. Five workshops were held in March and April 2000.

Sources: Federal Energy Regulatory Commission, "Regional Transmission Organizations, Order No. 2000," 18 CFR Part 35 (December 20, 1999); L.S. Hyman, *What's Inside FERC's Transmission Policy: A Guide To Order 2000* (Vienna, VA: Public Utilities Reports, January 2000).

users. Such rates may not reflect the cost of scarcity when there is a bottleneck on the grid, the costs of expanding capacity to remove such a bottleneck, or the costs of transmitting power over long distances.

In addition to the potential inefficiencies, each transmission owner had its own rate structure which worked when the industry was totally regulated and wholesale electricity markets were relatively small or nonexistent and electricity trading was infrequent. Competitive wholesale power markets require more efficient and equitable pricing methods that eliminate the possibility of pancaked pricing which can double or triple the price of the transaction, making it more difficult for electricity suppliers that have to cross multi-transmission boundaries to be cost competitive. Under Order 2000, RTOs will be required to design pricing methods that eliminate pancaked prices. Also, Order 2000 encourages RTO applicants to consider innovative transmission pricing methods such as performance-based ratemaking (PBR), or levelized rates, to replace the inefficient transmission pricing methods currently used.

Improve management of transmission congestion: Transmission congestion occurs when a transmission line reaches its transmitting capacity and additional power from a specific generator cannot be dispatched as needed. Congestion is caused by generation or power grid outages, increases in energy demand, loop flow problems, or a combination of these factors.

In the past, transmission owners had responsibility for the management of congestion on their transmission systems. Usually, adequate transmission facilities existed to support the flow of electricity within each transmission owner's system; however, when congestion occurred, the common approach was to curtail power to relieve the congestion. In a competitive environment, administrative curtailment is no longer an acceptable technique for congestion management. By not evaluating the costs of congestion, administrative curtailment provides no price signals or economic incentives to reduce congestion, and in that respect it is incompatible with competitive markets. In Order 2000, the Commission requires that an RTO develop mechanisms that measure congestion costs and that market participants are made aware of the cost consequences of their transmission usage decision. FERC leaves it up to the RTO to design a congestion pricing method to suit its needs.

Improve reliability of the transmission grid: Because an RTO typically covers a larger region, it enhances coordination among key players during system emergencies. Additionally, it can better coordinate or schedule generation and transmission outages and the sharing of ancillary services. An independent RTO can conduct more objective reliability studies of the system than others who may have vested interests in certain outcomes.

Major Issues in Forming a Regional Transmission Organization

Creating RTOs nationwide is a formidable task, and many difficult issues must be addressed. In addition to the problems unique to each region of the country, there are also generic problems applicable to all regions. Three important generic issues are the RTO's size, organizational structure, and transmission grid coverage.

Determining the appropriate size of an RTO: The Commission did not prescribe boundaries for an RTO, but notes that a region sized appropriately will be sufficient to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. The Commission specified regional configuration factors to evaluate the appropriateness of the proposed RTO's configuration. The region configuration should be large enough so that the RTO can make accurate and reliable ATC calculations, resolve loop flow issues internally within the region, manage congestion effectively, offer non-pancaked transmission rates, effectively operate one OASIS site, and conduct transmission planning and expansion effectively. The specific boundaries of an RTO will be evaluated using nine criteria (Table 12, Minimum Characteristic 2).

A reading of Order 2000 requirements with respect to the appropriate size of an RTO makes clear a few points. FERC does not have any apparent preconceived notion of the appropriate size of an RTO, only that determining the right size will involve evaluating many factors. One size does not fit all regions, so different configurations are likely. To maximize the benefits of an RTO, it appears that the larger the region covered by the RTO the better, to a point. Technical factors, as well as managerial, economic, and political factors need to be evaluated to determine an optimal size.

Determining the appropriate ownership structure of an RTO: One of the most important factors in determining the appropriate ownership structure for an RTO is its ability to achieve independence from market participants.[93] FERC commented in Order 888 that "the principle of independence is the bedrock upon which the ISO must be built and that this principle must apply to all RTOs, whether they are ISOs, transmission companies (Transcos), or variants of these two models. Order 2000 enumerates three conditions for independence: (1) the RTO's employees and any nonstakeholder directors must not have any financial interest in any market participants; (2) the RTO must have a decision-making process that is independent of control by any market participant or class of participants; and (3) the RTO must have exclusive and independent authority to file changes to its transmission tariff with the Commission under section 205 of the Federal Power Act.

The effect of ownership on an RTO's independence depends on which ownership model is used. The two basic models are the ISO model and transmission

[93] A definition of "market participant" was problematic, and FERC, after considering extensive comments, concluded that market participants is an entity whose economic or commercial interest is likely to be affected by an RTO's decision and actions. The Regulatory Text, Part 35, Chapter I, Title 18 CFR, 35.34(b2) contains a full definition of "market participant."

company (Transco) model. With the ISOs that are currently operating, ownership of the transmission facilities remained with the vertically integrated electric utility, but operating control of the facilities was transferred to the ISO. These ISOs operate as nonprofit and nonshare companies and their independence from market participants is established through representation and voting privileges of its governing board.

The Transco is an independent, self-sustaining, profit-making transmission company. Under this model, the Transco owns the transmission facilities and the issue of independence concerns ownership of the company itself. The Commission noted that it will permit market participants to retain limited active ownership (up to 5 percent for a single market participant and 15 percent for a class of market participants) in the RTO during a 5-year transition period. Active ownership refers to ownership of voting securities that gives the owner the ability to influence or control an RTO's operating and investment decisions. An active ownership interest will terminate after 5 years.

In Order 2000, FERC has noted its openness to consider any type of ownership and governance structure as long as the RTO's design meets the minimum characteristics requirement of Order 2000. FERC has stated that "it is important that we provide current transmission owners with flexibility in deciding how they will relinquish ownership or control of their transmission facilities to an RTO." Flexibility in ownership allows for regional differences.

Avoiding gaps in regional coverage of the transmission grid: For an RTO to realize its full potential, its must have control and authority over the entire transmission grid in the region. Gaps or breaks in continuity of coverage of the grid undermine the RTO's effectiveness and the achievement of the benefits it can provide.

Because joining an RTO is voluntary, some utilities may decide not to participate. IOUs choosing not to participate are required to file reasons and obstacles for not participating. This procedure should invoke a dialogue with FERC and provide a mechanism to overcome obstacles to participation. Because IOUs are jurisdictional utilities, FERC also has some leverage in convincing IOUs to participate.

On the other hand, federally owned and other public power and cooperative utilities are non-jurisdictional utilities; they have no filing requirements under Order 2000 and FERC has no apparent leverage in obtaining their participation. Because these utilities own approximately 30 percent of the Nation's power grid, the potential exists for substantial gaps in regional coverage. For example, in the northwest and southeast regions of the United States, federally owned utilities are major providers of electricity with substantial ownership in transmission facilities. RTO formation in those regions may be impractical without their participation.

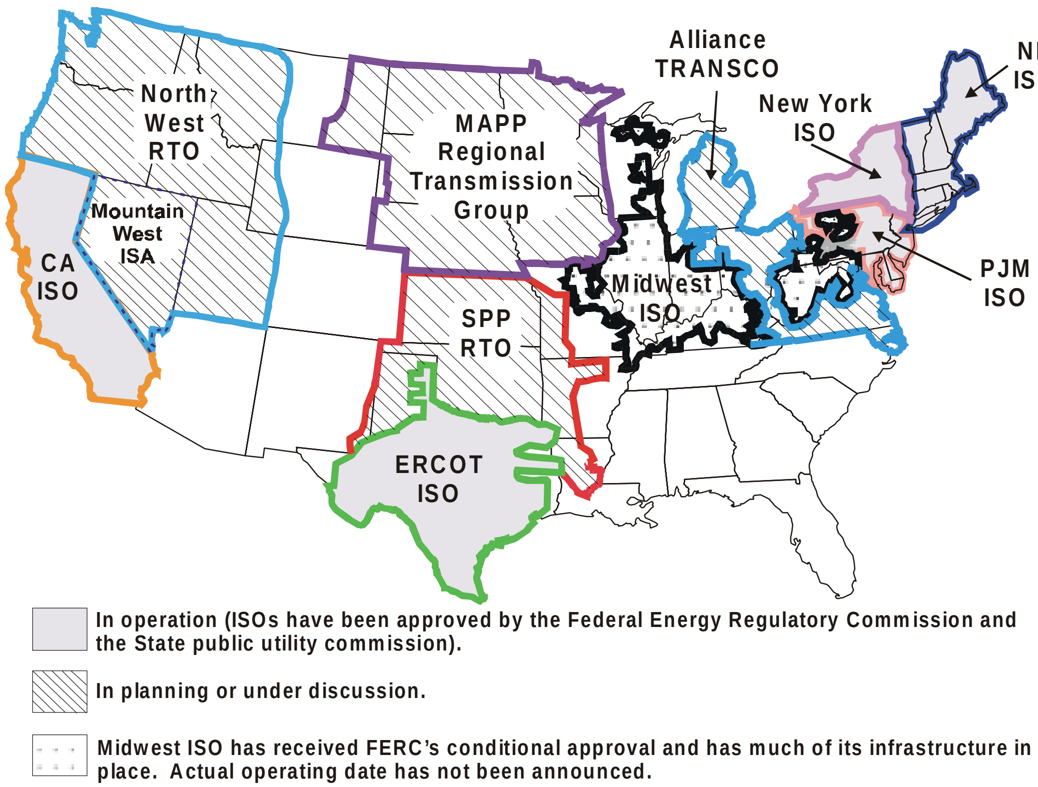
In Order 2000, FERC encourages non-jurisdictional utility participation, but also recognizes that municipally owned utilities face numerous regulatory and legal obstacles. The Internal Revenue Code has private use restrictions on the transmission facilities of municipally owned utilities financed by tax-exempt bonds. State and local government limitations, such as prohibitions on participating in stock-owning entities and other restrictions, may also impede full participation. FERC, through the collaborative process, seeks solutions to these problems, but the outcome is uncertain.

Status of Regional Transmission Organizations

Although FERC has encouraged formation of independent RTOs, development of them has been sporadic; most of the Nation's transmission grid is not under control of an independent RTO. Five ISOs have formed over the past 2 years and are now operating—California ISO; Pennsylvania, New Jersey, Maryland (PJM) ISO; ISO New England; New York ISO; and ERCOT ISO (Figure 27). The Midwest ISO has received regulatory approval and much of its operating infrastructure has been assembled; it should take operating control of the transmission grid in the near future.

Several factors have contributed to the current set of approved ISOs. PJM, New England, and New York ISOs were created from existing tight power pools. A tight power pool functions as one control area. Unlike ISOs, power pools did not have control of transmission facilities, they were not independent from transmission owners, and they did not administer a regional open access transmission tariff. According to Order 2000, "it appears that the principal motivation for these tight power pools forming ISOs was to establish a single system-wide transmission tariff as required by Order 888." In contrast, State legislation that opened California's electric industry to retail competition required the formation of the California ISO. The Public Utility Commission of Texas created the ERCOT ISO. Originally, the Midwest ISO consisted of voluntary members. Subsequent to its initial formation, electric

Figure 27. Independent System Operators and Regional Transmission Organizations in Operation or Under Discussion as of April 1, 2000



Notes: • Creation of regional transmission organizations (RTOs) is currently under rapid development. Under Order 2000, utilities not currently members of an approved ISO must submit plans to join an RTO by October 2000. Utilities that are members of an ISO must submit plans to form an RTO by January 2001. • MAPP and the Midwest ISO have reached an agreement to merge operations. Mountain West is an independent system administrator which is considered an interim organization in a broader regional transition plan.

Source: Compiled from information obtained in trade journals and websites maintained by the regional transmission organizations.

utilities in Illinois and Wisconsin have joined the Midwest ISO because of State legislation requiring either utility participation in an ISO or divestiture of their transmission assets.

A comparison of the six ISOs show many similarities, although many of the implementation details are different (Table 13). All of the ISOs are nonprofit organizations. Four of the ISOs operate as a single control area; ERCOT and the Midwest ISO have multiple control areas within their regions.

With the exception of the ERCOT ISO, all other ISOs have developed a single access charge to the ISO-controlled transmission systems, based on the costs of the transmission owner serving the customer. Access charges are used to recover the transmission owner's embedded transmission system costs, and are calculated based on dollar per megawatthour of transmission system usage. Under this system, the transmission customer pays only one access charge regardless of the number of individual transmission systems crossed in the ISO-controlled grid, so pancaked charges have been eliminated. Most of the ISOs are moving toward development of one uniform access charge for the entire ISO-controlled grid.

Three of the ISOs (California, PJM, and New York) use bid prices to manage transmission congestion in their region. In general, the power generators submit voluntary bids to reduce output and relieve congestion, and the ISO uses the bids to calculate the costs (or price) of transmission congestion. The costs are assigned to the appropriate transmission user. This technique places a value on congestion and it provides a basis for economic decision-making. Managing transmission congestion

Table 13. Selected Information on Independent System Operators

	California ISO	ERCOT Texas ISO	ISO New England	MidWest ISO (MISO)	New York ISO	Pennsylvania, New Jersey, Maryland (PJM)–ISO
Operating Date	March 31, 1998	August 1996	1997	Approved 1998. Not yet operating	1999	April 1998
States Covered	California	Texas	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont	Illinois, Indiana, Kentucky, Missouri, Ohio, Maryland, Pennsylvania, Virginia, West Virginia, Wisconsin	New York, New Jersey	Delaware, New Jersey, Maryland, Pennsylvania, Washington, DC, Virginia
Number of Transmission Owners	3	16	15	13	8	10
Type of Organization	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit
Board of Directors	24 members representing 13 stakeholder classes	18 members representing 6 stakeholder classes	10 independent members	8 independent members	10 independent members	8 independent members
Control Areas	Single	Multiple	Single	Multiple	Single	Single
Transmission Rights Program	Under development	None	Under development	Undecided	Transmission congestion contracts	Fixed transmission rights
Transmission Congestion Management	Price based [a]	Priority based	Priority based	Priority based	Price based	Price based
Transmission Access Charges [b] (Method to Meet Revenue Requirements)	Charge is based on the embedded cost of the transmission owner serving the customer	System-wide (postage stamp) charge	Charge is based on the embedded cost of the transmission owner serving the customer	Charge is based on the embedded cost of the transmission owner serving the customer	Charge is based on the embedded cost of the transmission owner serving the customer	Charge is based on the embedded cost of the transmission owner serving the customer
Ancillary Services	ISO procures if not provided	ISO coordinates	ISO can provide	ISO will arrange for services	ISO can provide	ISO provides or coordinates
Transmission Planning	ISO leads coordinated process	ISO coordinates	NEPOOL has lead role	ISO develops plan with transmission owners	ISO is an active participant	ISO prepares plan
Operation of a Centralized Power Market	Separate from ISO	None	Combined with ISO	None	Combined with ISO	Combined with ISO

Table 13. Selected Information on Independent System Operators (Continued)

	California ISO	ERCOT Texas ISO	ISO New England	MidWest ISO (MISO)	New York ISO	Pennsylvania, New Jersey, Maryland (PJM)–ISO
Type of Centralized Power Markets	The California power exchange manages the day-ahead and hour-ahead markets. The ISO manages the ancillary services, real-time imbalance, and congestion markets.	None	One residual day-ahead market (only the difference between participant's energy resources and obligations can be bidded); All transactions are priced at *ex-post* energy clearing price.	None	Day-ahead and real-time market; both ISO settled; additional bids can be submited and non-accepted bids resubmitted (hour-ahead bids) up to 90 minutes before dispatch hour in the real-time market.	One real-time joint market for energy and reserves; generators submit hourly bids for their resources once daily; these resources are used by the ISO for energy and reserves.

[a]Price based means that the ISO calculates the costs of congestion and allocates these costs to the appropriate transmission user. Priority based means that the ISO curtails power generation based on a predetermined curtailment plan.

[b]All of the ISOs will be phasing in one system-wide transmission access charge.

Sources: L.D. Kinsch, "Pricing the Grid: Comparing Transmission Rates of the U.S. ISO," *Public Utilities Fortnightly* (February 15, 2000). Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues 1998*, DOE/EIA-0562(98) (Washington, DC, July 1998), pp. 34-35.

using energy prices is a relatively new and innovative application, and it is likely that RTOs now being formed will experiment with these new techniques.

Four of the regions—California, PJM, New York, and New England—have established centralized markets for buying and selling energy in their respective regions. In California, the California Power Exchange, which is a separate organization from the California ISO, runs their energy market. Operation of the energy markets and the ISO are combined in the other regions. These centralized markets are new, and the rules of operation will likely evolve as more operating experience is acquired.

With respect to meeting the requirements of Order 2000, ISOs have until January 1, 2001, to submit a filing to FERC specifying their plans for forming an RTO. None of the existing ISOs have announced publicly their specific compliance plans. It is unlikely that the existing organizational structure of these ISOs will satisfy all of the minimum characteristics and minimum functions required of an RTO (Table 12), so one can expect to see changes in the ISO organizational structures and functions over the coming years. Electric utilities not currently members of an ISO have to file plans to form an RTO by October 1, 2000. In some regions, progress toward compliance with Order 2000 has been made as demonstrated by the following examples.

- The most significant announcement was the planned merger between the Midwest ISO and the Mid-Continent Area Power Pool (MAPP). This arrangement has the potential of creating one RTO from east of the Rocky Mountains up to the border of the PJM ISO (Figure 27).

- The Southwest Power Pool (SPP) has filed with FERC seeking formal recognition as an ISO. It also requested that the Commission recognize that it satisfies minimum requirements for an RTO. In May 2000, FERC ruled that SPP's proposal does not have the operational authority, independence, and other requirements to qualify as an RTO.

- In June 1999, the Alliance Companies, consisting of five large IOUs located in Michigan, Ohio, and Virginia, filed with FERC an application to transfer their transmission facilities to a Transco. FERC conditionally approved the transfer of ownership and the general framework of the Transco as meeting the requirements of an ISO subject to certain revisions. In May 2000, FERC ruled that the Alliance Transco does not meet the independence requirements of an RTO.

- Recently, FERC accepted the creation of Mountain West as an Independent System Administrator (ISA) and conditionally approved the transfer of transmission facilities belonging to Nevada Power and Sierra Power to the ISA. FERC did not evaluate Mountain West under its ISO or RTO principles. Mountain West is considered an interim step in a broader regional transition plan in the western region.

- In response to FERC's Order 2000, nine transmission-owning utilities are working together to form the Northwest RTO.

Wholesale Electricity Trading Hubs and Power Exchanges

Coinciding with FERC's promotion and approvals of market-based rates for the sale of electricity, the industry has experienced a significant change in the way power is sold. Most noticeable is the emergence of centralized power markets where electricity suppliers submit bids to sell power in regional markets. The market operator evaluates the bids and selects the most economical bid to meet energy demand in the region. Four centralized power markets are now operating—California PX, New York ISO, ISO New England, and PJM-ISO (Figure 28). Of the four operating markets, the California Power Exchange may be the most active because California's three major electric utilities were until recently required by State law to sell all of their power through the exchange. Participation in the other power markets is voluntary and currently most of the power in these regions is sold through bilateral arrangements between buyer and seller. This may change as buyers and sellers gain more experience with centralized power markets.

To support bilateral power trading, numerous electricity trading hubs have emerged over the past few years. A hub is a location on the power grid representing a delivery point where power is sold and ownership changes hands. Potentially, each control area on the power grid could become a trading hub, but a few hubs account for the bulk of power trading (Figure 28). Of the 10 major trading hubs, five of them are located in the western United States, four in the midwest, and one in the east.

Part of the reason that these major trading hubs have emerged is because the New York Mercantile Exchange (NYMEX) and the Chicago Board of Trade (CBOT) have developed and sponsored electricity futures contracts to facilitate trading at these hubs. A futures contract is a common risk management tool used in agricultural, metal, and energy commodities markets. One of the main purposes of a futures contract is to eliminate the risk of price changes. For example, a power marketer entering into a contract to sell power at a predetermined price at the California Oregon Border (COB) runs the risk that the price it must pay for electricity will increase before the power is delivered. However, the power marketer can hedge its risk by buying electricity futures that match the quantity and timing of the original power contract. NYMEX has created electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. CBOT has created electricity futures contracts for the Commonwealth Edison and Tennessee Valley Authority trading hubs.

Market Power in Wholesale Electricity Markets

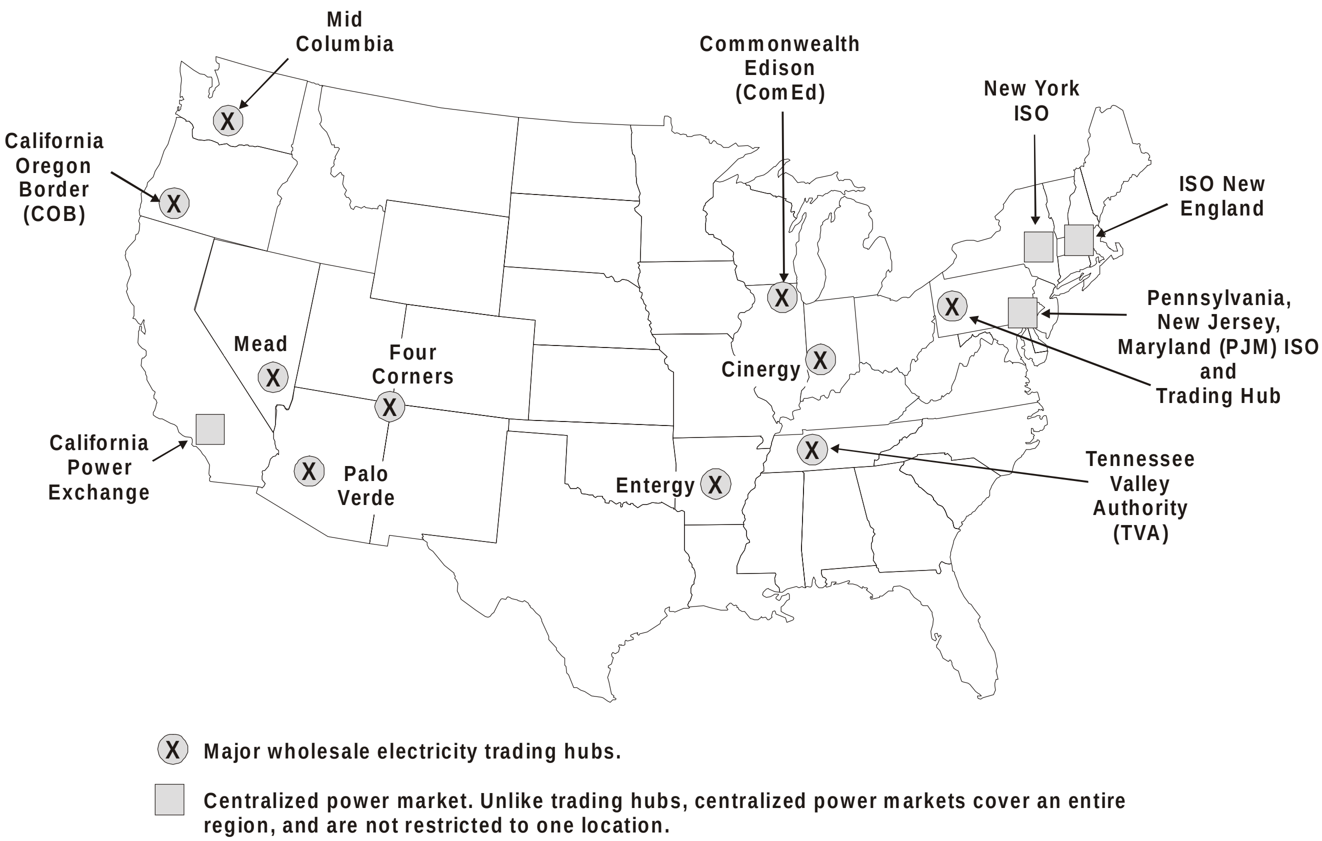
Market power is the ability of an electricity supplier to raise prices profitably above competitive levels and maintain those prices for a significant time. Electricity suppliers exercising market power force consumers to pay higher electricity prices than they would pay in a competitive market.

Market power exists in two forms—horizontal and vertical. Vertical market power may occur when a firm controls two related activities. In the electric power industry, one firm controlling both electricity generation and transmission has the potential to exercise vertical market power. Separating control of electricity generation from control of the transmission system (via ISOs and RTOs) is designed to eliminate the potential for vertical market power. Horizontal market power is more difficult to eliminate. Horizontal market power may occur when a firm controls a significant share of the market. In the electric power generation business, one firm controlling a significant share of electric generation capacity in a particular region has the potential to exercise horizontal market power. [94]

FERC and State regulators are interested in seeing that market power abuses do not undermine the potential benefits of competitive markets. To meet this objective, FERC requires ISOs and RTOs to monitor bulk power markets for abuses and design flaws, and to report

[94] A detailed discussion of horizontal market power and its effects on competition can be found in a report prepared by the U.S. Department of Energy, Office of Economic, Electricity, and Natural Gas Analysis, "Horizontal Market Power in Restructured Electricity Markets," DOE / PO-0060 (Washington, DC, March 2000).

Figure 28. Major Wholesale Electricity Trading Hubs and Centralized Power Markets



Notes: Power trading also occurs at locations not indicated on the map. The New York Mercantile Exchange (NYMEX) has established electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. The Chicago Board of Trade has established electricity futures contracts for the ComEd and TVA trading hubs.

Source: Electric industry trade journals and Internet websites.

market anomalies to FERC and other effected regulatory authorities. This market monitoring function is critical, particularly now as new competitive bulk power markets develop across the country.

A report prepared recently by the California ISO's Department of Market Analysis demonstrates the crucial role of market monitoring.[95] The report documents that recent spikes in California's electricity prices over this summer were attributable, in part, to some electricity suppliers exercising market power. The report noted that "the presence of market power can be verified by bid prices significantly over the variable costs of many suppliers in the ISO's market."

Price spikes in wholesale power markets in California and New York have prompted FERC to conduct an investigation of all electric bulk power markets to determine whether they are working efficiently and, if not, the causes of the problems. Their report is scheduled to be completed November 1, 2000.

Conclusion

By providing the capability to move power over long distances, the transmission system is an integral component of the Nation's electric power industry. Nondiscriminatory access to the transmission system for all electricity suppliers is critical to creating competitive power markets. For more than a decade, FERC has been pushing for the development of competitive wholesale power markets and opening the transmission system to all qualified users. Since the late 1980s, FERC has

[95] California ISO, Department of Market Analysis, "Report on California Energy Market Issues and Performance: May-June 2000" (August 2000).

approved more than 850 applications from electric utilities, power marketers, and independent power producers to use market-based rates to sell power competitively in wholesale markets. In 1996, the Commission issued Order 888, which opened the transmission system to all qualified power producers and marketers. Prior to Order 888, independent power producers and power marketers had difficulty accessing the transmission grid to deliver power.

Over the past few years, FERC has also encouraged regionalization of the transmission grid whereby vertically integrated electric utilities transfer control of their transmission facilities to an independent transmission organization. Independent means generally that the transmission organization does not have an economic interest in buying or selling electricity. The independence from the electricity market helps to ensure fair and comparable access to the transmission grid. In addition, regionalization of control of the transmission grid promotes improved operating efficiency, simplified and more efficient transmission pricing, and improved reliability.

In an ambitious move to promote regional control of the transmission system, FERC recently issued Order 2000 encouraging all electric utilities to transfer control and/or ownership of their transmission facilities to an independent RTO. Utilities that are not currently a member of an existing regional organization are required to submit plans to join an RTO by October 2000; utilities that are members of an existing regional organization are required to submit their plans to join an RTO by January 2001. It is possible that compliance with Order 2000 will reduce the ownership and control of the Nation’s transmission grid to a handful of independent transmission companies over the next few years, but there is much uncertainty about the ultimate effects of Order 2000.

Both this chapter and the preceding chapter have discussed restructuring activities at the Federal level. The following chapter examines the roles of the States.

8. The Role of the States in Promoting Competition

In the years following enactment of EPACT, there has been a surge of activity in State legislatures and at utility commissions to examine various issues with respect to the electric utility industry. Critical among them has been a wide range of activities designed to promote industry competition at the retail level and to complement the wholesale wheeling and stranded cost initiatives of the Federal Energy Regulatory Commission (FERC). In 1999, customers in 12 States could actually choose their electricity supplier. In California, Rhode Island, Massachusetts, and New Jersey almost all customers had the right to choose. In Arizona, Delaware, Illinois, Michigan, Montana, New Hampshire, and New York customer choice is still being phased in. In Pennsylvania, where two-thirds of customers could choose in 1999, as of January 1, 2000, all customers can choose their electricity supplier.

Regulatory Activities

Not all State commissions have moved with the same zeal, even though most of them have under consideration the merits and implications of competition, deregulation, and electric utility industry restructuring. States with high electricity rates, such as California and those in the Northeast, have had compelling reasons to promote competition in the hope of making lower rates available to their customers in general.

As an example, the California Public Utility Commission (CPUC) directed an examination of the comprehensive set of regulatory programs to explore alternatives to what was then the current regulatory approach based on conditions and trends identified in its Decision No. 92-09-088 of September 1992.[96] The directive resulted in the submission of a staff report—generally known as the "Yellow Book"—to the CPUC in February 1993.[97]

The "Yellow Book" study concluded that the State should reform its regulatory program, including a redefinition of the prevailing regulatory compact, and offered strategies to address shortcomings of its regulatory framework. Based on a comprehensive reexamination of the electric utility industry in the State and the regulatory policy under which the industry functioned, the CPUC opened rulemaking and investigative proceedings to consider its proposed restructuring policies in early 1994.[98] These initiatives, popularly known as the "Blue Book" proposals, outlined a strategy to replace the traditional cost-of-service regulatory framework with alternatives that focused on utility performance and, where possible, the discipline of the market. Subsequent regulatory and legislative activities in California will be presented in more detail as one of the five case studies that follow later in this chapter.

Other States have not moved with such enthusiasm, however. In December 1998, 23 State public utility commissions sent Congress a letter expressing concerns that issues affecting them may not be given adequate consideration in the debate about restructuring. Kentucky, whose electricity prices are the lowest east of the Rocky Mountains, is one of these States. Recently, Kentucky's Special Task Force on Electricity Restructuring concluded that there are no compelling reasons to restructure their electric power industry.

States such as Idaho and Nebraska have taken the view that the main tenets of EPACT (as pertaining to promoting competition) are difficult for them to implement.

The Idaho Public Utilities Commission (IPUC), for example, has stated that it is not its role to actively attempt to bring about deregulation of the industry. The IPUC expressed the concern that rates in Idaho could go

[96] California Public Utility Commission, Decision 92-90-088, W4, 43, "Order Instituting Investigation on the Commission's Own Motion to Implement the Biennial Resource Plan Update Following the California Energy Commission's Seventh Electricity Report" (September 16, 1992).

[97] Refer to California Public Utility Commission, *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future* (San Francisco, February 1993).

[98] California Public Utility Commission, "Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation and Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring of California's Electric Services Industry and Reforming Regulation," Docket Nos. R.94-04-031 and I.94-04-032 (April 20, 1994).

up, and, at the same time, deregulation could result in the diminution of the quality of service enjoyed by the ratepayers in the State.[99] The Nebraska Public Power District (NPPD) maintains that applying reciprocity requirement provisions of FERC Order 888 violates Nebraska's law and its constitutional rights.[100] The NPPD has, however, continued to monitor the development of regional transmission organizations and independent transmission companies. NPPD has created a new position—Vice President of Transmission Services—to focus on restructuring outside its boundaries and how external activities might affect NPPD.[101]

In 1996, Idaho, Kentucky, and Nebraska ranked first, second and twelfth, respectively, in lowest average revenue per kilowatthour.[102] In 1998, they ranked first, third and ninth, respectively. It is not surprising that they are not the States that are leaders in the restructuring movement.

Like California, Kentucky is one of the five States that will be examined in detail later in this chapter. The others are Massachusetts, Pennsylvania, and Texas. Massachusetts and Pennsylvania were chosen because they, like California, were among the earliest States to embrace restructuring although they have had vastly different experiences. Texas was chosen because it is a large State that is in the planning stage for instituting competition.

Legislative Activities

All State utility commissions typically enjoy broad regulatory authority to ensure that electric utilities in their jurisdictions provide fair, just, and reasonable electricity rates to their customers. In addition, State commissions are also empowered to regulate various other aspects of power generation, transmission, and distribution at the State level. However, not all commissions may be endowed with the necessary legal authority to manage an evolving competitive market structure. Accordingly, legislation in some States is designed primarily to grant the utility regulatory agency the authority to address the restructuring issues or to consider alternative rate-making processes (incentive- or performance-based regulation). Elsewhere, State legislators show a serious interest in finding out how the State could respond to new competitive pressures emerging in the electric industry.[103] Exploratory activities may also be promoted at the behest of the State legislators in an effort to gain additional insights.[104] In some cases, legislative actions may become necessary to adopt decisions recommended by the commission(s) for implementation.

As of July 1, 2000, 24 States[105] and the District of Columbia had enacted legislation or passed regulatory orders to restructure their electric power industries. Alaska and South Carolina had legislation or regulatory orders pending. Sixteen States[106] still had ongoing legislative or regulatory investigations, and there were 8 States[107] where no restructuring activities had taken place (Figure 23).

Case Studies

This section presents the current status of restructuring in five States: California, Kentucky, Massachusetts, Pennsylvania, and Texas. California, Pennsylvania, and

[99] Idaho Public Service Commission's Order No. 26555, Case No. GNR-E-96-1, "In the Matter of the Commission's Investigating into Changes Occurring in the Electric Industry" (August 16, 1996).

[100] Note that Nebraska has no privately owned electric utilities. All generation, transmission, and distribution service in Nebraska is provided by public entities, municipalities, and cooperatives whose governing boards are responsible to, and serve at the voting pleasure of, rate-paying Nebraska residents.

[101] Nebraska Public Power District, *1999 Annual Report*, p. 5.

[102] Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999).

[103] On July 3, 1995, Legislative Resolve to Require a Study of Retail Competition in the Electric Industry became Maine law. This legislation directed the Maine Public Utilities Commission (MPUC) to undertake a study to develop at least two plans for an orderly transition to a competitive market. The MPUC released its draft report on July 19, 1996.

[104] The New Hampshire legislature, for example, passed legislation in June 1995 directing the New Hampshire Public Utility Commission (NHPUC) to establish a pilot program to examine the implications of retail competition. In its order establishing preliminary guidelines for a retail competition pilot program, the NHPUC noted that the program was not necessarily a step toward wide-scale competition but was rather a way to examine the implications of an obstacle to a competitive retail market at a time when supply shortages are not a concern. Subsequent legislation (HB-1392), enacted in May 1996, directed the NHPUC to undertake a generic proceeding to develop and establish a final order establishing a statewide electric utility restructuring plan no later than February 28, 1997.

[105] Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia.

[106] Alabama, Colorado, Florida, Indiana, Iowa, Louisiana, Minnesota, Mississippi, Missouri, North Carolina, North Dakota, Utah, Vermont, Washington, Wisconsin, and Wyoming.

[107] Georgia, Hawaii, Idaho, Kansas, Kentucky, Nebraska, South Dakota, and Tennessee.

Massachusetts were chosen because they were among the first States to institute restructuring at the retail level and they did so differently. Texas has recently passed restructuring legislation and its utilities and public utility commission are planning for competition which will begin in 2002. Kentucky was chosen to serve as an example of a State that has done little to restructure; in fact, current policy is to maintain the status quo and put off restructuring until there is a compelling reason to do so.

California

In 1996, the average revenue per kilowatthour (which is used as a proxy for price) of electricity sold in California was 9.48 cents,[108] the tenth highest rate among the 50 States and the District of Columbia. This rate was one factor leading Governor Pete Wilson to sign Assembly Bill 1890 (AB1890) on September 23, 1996. This new law established a 4-year transition period to make the State's electric power industry competitive. To implement it, retail competition, allowing customers to choose their electricity, began on March 31, 1998. Rates were frozen at the levels in effect as of June 10, 1996, and a 10-percent rate reduction was guaranteed for residential and small commercial users.[109] These rates will remain frozen until March 31, 2002. As of December 31, 1999, the State has 209,752 direct access customers. This number represents 2.1 percent of the total number of eligible customers and 13.8 percent of the total load.[110] Industrial customers, who generally use more electricity than residential customers, account for a major share of this load. These customers are currently served by 35 electric service providers registered with the CPUC.[111]

AB1890 also contained provisions for the creation of an independent system operator (ISO) and a legally separate power exchange (PX) out of concern about market power issues. To ensure that utilities do not continue their traditional monopolistic advantage by controlling generation, transmission and distribution, the ISO and PX are independent of the utilities.[112] The law allows for stranded cost recovery in California. Utilities may apply the difference between their actual operating costs and the frozen rate toward recovering their stranded costs. A "Competition Transition Charge" based on the sales volume appears on consumers' bills along with another charge that finances the bonds that provided the rate reduction.[113] A subsequent law requires retail suppliers to disclose the sources of generation to customers; report fuel types and consumption to system operators who will make the information available to the California Energy Commission; and report emissions, purchased power, losses, and retail sales.[114]

The California ISO received FERC approval in October 1997, and became operational on March 31, 1998. The major responsibility of the ISO is to ensure fair and impartial access to the high-voltage transmission system for all generators, while maintaining reliable operation. The transmission system will continue to be owned by the investor-owned utilities (IOUs). The ISO will ensure that no particular buyer or seller of electricity can block access by others. Generators who ship electricity through the system will pay a fee to cover the system costs and to ensure reliability.[115]

The PX, regulated by FERC, also became operational on March 31, 1998. It serves as an auction market for the buying and selling of electricity. The three largest IOUs in the State—Pacific Gas & Electric (PG&E), Southern California Edison (Edison), and San Diego Gas & Electric (SDG&E)—must sell their power to the PX. If they wish to, municipalities, independent power producers, irrigation districts, and out-of-state producers may also sell power to the PX.

The PX accepts requests to buy a quantity of electricity at a given price. The PX functions like an auction to match total demand for power with generation of power. It creates a spot market where price information

[108] Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999), p. 29.
[109] California Public Utility Commission, "Plug In, California!," http://www.cpuc.ca.gov/divisions/csd/electric/PlainEnglish981030.htm.
[110] Energy Information Administration, "An Overview of the Electric Power Industry," presentation to staff of the U.S. Senate Committee on Energy and Natural Resources (March, 2000).
[111] California Public Utility Commission, http://www.cpuc.ca.gov/electric_restructuring/esp_registration/providers/esp_udc.htm.
[112] California Public Utility Commission, "Plug In, California!," http://www.cpuc.ca.gov/divisions/csd/electric/PlainEnglish981030.htm.
[113] Energy Information Administration, "Status of State Electricity Industry Restructuring Activity: Stranded Costs as of May 2000," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html#CA.
[114] California Energy Commission, "Electricity Industry Restructuring – What it is and will it affect me?," http://www.energy.ca.gov/restructuring/restructure_FAQ.html.
[115] California Public Utility Commission, "Plug In, California!," http://www.cpuc.ca.gov/divisions/csd/electric/PlainEnglish981030.htm.

is publicly available. The PX then solicits bids from electricity generators and chooses the lowest bidders until it has enough supply to meet the requests to buy power. The prices change on an hourly basis.[116]

PG&E, Edison, and SDG&E were ordered to buy their power from the PX for 4 years after its inception to resell to customers who buy electricity from the utility distribution companies. They will pay a price determined by the PX based on the market demand for power. This was done to foster fair competition between utilities and other electricity suppliers.

However, in a recent development, California regulators are poised to amend the requirement that the State's IOUs buy all their power through the PX. The Automated Power Exchange of Santa Clara and other rivals have consistently opposed the mandate that the IOUs buy from the PX and they have won support from two commissioners, Josiah Neeper and Richard Bilas. They have introduced a proposal that would allow utilities to buy from any approved exchange.[117]

AB1890 established a public benefit program for low income assistance, energy efficiency, research and development programs, and programs to encourage renewables. It was anticipated that approximately $540 million would be collected over 4 years by a non-bypassable wires charge.[118] Approximately 30 local governments have switched to Commonwealth Energy, which is supplying geothermal energy from Lake, Sonoma, and Imperial counties. Santa Monica, in Los Angeles County, is currently the world's largest all-renewable city, but Oakland is considering making purchases that would put it in the global lead.[119]

PG&E, Edison, and SDG&E have divested a large amount of generating capacity to address concerns about market power. To date PG&E has divested itself of 7.4 gigawatts of capacity at a sale price of $1.5 billion. Edison has sold 10.6 gigawatts for $1.2 billion. SDG&E has completed transactions of 2.1 gigawatts for $475 million.[120] California has been cited as "leading the way with merchant plant proposals." The California Energy Commission approved three merchant plant proposals in 1999, has seven applications under review, and anticipates 11 more proposals.[121]

In June 1999, the CPUC began public hearings on opening distribution to competition. The formal opening of the proceeding in December 1998 resulted in responses from numerous stakeholders. Some have suggested waiting until competition in the generation market has matured before attempting to open distribution to competition.[122]

The California electricity market was in turmoil during the summer months of 2000. There were periods of rolling blackouts around the San Francisco area. Prices in the San Diego region more than doubled. A scorching summer exacerbated these conditions. Some stakeholders have called to re-regulate the industry, while others have called for market reforms. In the meantime, the California ISO set price caps to contain wholesale prices over the summer. The cap was initially set at $750 per megawatthour and was lowered to $250 per megawatthour in August 2000.

California's high electricity prices have been linked to three causes: a deficiency of generating capacity in California; a market system that does not permit enough forward market trading as a means of managing supply and demand risk; and a system that does not allow sufficient customer response to high prices. The California ISO sees improving consumer response to increasing prices and opening the market to new electricity suppliers as fundamental solutions to the recent instability.[123]

Government executives and agencies have offered short-term relief to high prices. On August 2, 2000 Governor

[116] *Ibid.*
[117] American Public Power Association, *Public Power Daily* (May 18, 2000).
[118] Florida Public Service Commission, "Electric Restructuring Activities Update," http://www.psc.state.fl.us/general/publications/restruc.htm.
[119] *The Electricity Daily*, Vol. 14, No. 98 (May 22, 2000).
[120] California Energy Commission, "Electric Generation Divestiture in California," http://www.energy.ca.gov/electricity/divestiture.html.
[121] *The Energy Report* (Arlington, VA: Financial Times Energy, January 3, 2000), p. 5.
[122] Energy Information Administration, "Status of State Electricity Industry Restructuring Activity as of May 2000," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html#CA.
[123] California Independent System Operator, *Report on California Energy Market Issues and Performance, May-June 2000* (August 10, 2000), p. I.

Gray Davis issued three executive orders aimed at stabilizing prices, increasing supply, and reducing peak demand.[124] The Low Income Home Energy Assistance Program and the Small Business Administration released more than $2 million in emergency funds to assist low-income households and small businesses in the San Diego area.[125]

Responding to San Diego Gas & Electric's petition to reduce wholesale prices, FERC ordered a hearing on August 23, 2000 to investigate if the electricity rates are just and reasonable. Should FERC conclude that the rates were unreasonable, it could order refunds under authority granted by the Federal Power Act for sales that occurred after August 23. Subsequently, on September 21, FERC Chairman James Hoecker asked Congress for greater authority "to retroactively correct extraordinary wealth transfers" since the agency has limited authority to order refunds.[126]

Texas

Much of Texas is unique in that it is not subject to the control of FERC. As stated in Chapter 3, the United States has three separate power grids connected by a few direct current tie lines: the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect. Utilities within each interconnection coordinate operations and planning and buy and sell power among themselves. Because utilities in the Texas Interconnected System are not connected with other utilities outside the State and electric trade does not cross State boundaries for these utilities, FERC does not have regulatory jurisdiction over them. In 1998, Texas was near the middle of the rankings of all States and the District of Columbia with respect to electricity rates. In 1998, the average revenue per kilowatthour was 6.07 cents, which ranked as the 25th lowest in the country. With prices in the middle of the range of States, it is not surprising that Texas recently passed restructuring legislation.

In 1995, Senate Bill 373, which became the Public Utility Regulatory Act of 1995, was enacted to restructure the wholesale electricity market in Texas consistent with FERC requirements for unbundled transmission service. The law also required the establishment of an ISO. The ISO in the Electric Reliability Council of Texas (ERCOT) differs somewhat from the other ISOs. The ERCOT ISO does not participate in generation dispatch, in power exchanges, in providing ancillary services, or in establishing prices other than determining the cost of any redispatch needed to allow transactions to occur. In 1996, the Public Utility Commission (PUC) of Texas issued rules implementing the legislation that required transmission-owning utilities in the State to provide open access to the transmission system and ancillary services. The rule also required separation of transmission, distribution, and generation costs and rates, and the establishment of the ERCOT ISO.[127]

In 1999, Texas was the largest State to pass restructuring legislation. Governor George W. Bush signed Senate Bill 7 to introduce retail competition to Texas.[128] Retail choice will begin in 2002. The restructuring law freezes rates for 3 years or until 40 percent of a utility's customers have switched to an alternate provider, whichever comes first. The law is expected to give a boost to development of renewable energy sources. Utilities can recover an estimated $9 billion in stranded costs through securitization. In response to the law, TXU and Southwestern Public Service have already put some of their power plants up for sale.[129] Electric cooperatives and municipally owned utilities are exempt from customer choice unless their governing boards decide to open their markets to competition.

As of January 10, 2000, all Texas IOUs had filed detailed plans describing how they propose to unbundle their operations.[130] As of March 31, 2000, nine utilities had turned in their transition plan proposals to the PUC.[131] Utilities were required to state which aspects of their businesses would be deregulated and which portions would remain regulated. The companies were also required to describe how they would separate their businesses into a retail provider, a generation company, and a transmission and distribution utility. The electric

[124] "California Looks in Every Direction Seeking 'Fix' for Market Shock," *Electric Utility Week* (The McGraw-Hill Companies, August 7, 2000), p. 7.
[125] *The Energy Report* (Arlington, VA: Financial Times Energy, August 28, 2000), p. 1.
[126] American Public Power Association, *Public Power Daily* (September 22, 2000).
[127] Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999), p. 263.
[128] Public Utility Commission of Texas, Electric Competition Overview, http://www.puc.state.tx.us/ocp/competition/echome.cfm.
[129] *The Energy Report* (Arlington, VA: Financial Times Energy, January 3, 2000), p. 4.
[130] *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 7.
[131] *Dallas Morning News* (April 1, 2000), http://www.dallasnews.com.

companies were required to report the fees they would charge to retail competitors using the utilities' lines.[132] By September 2001, the PUC will begin to certify retail electricity providers. The Texas Pilot Program is scheduled to commence on June 1, 2001, and on January 1, 2002 retail choice is slated to begin with small commercial customer and residential electric rates decreasing by 6 percent. A proposal for a consumer education plan has been approved by State regulators. This marks the first step in implementing a consumer plan mandated by the restructuring law. The intent of the plan is to explain restructuring to customers and inform them of their options. Plans for northeastern Texas have been developed, and the PUC will strive to develop a plan with emphasis on non-English speaking and lower-income customers. The plan will most likely be implemented by early 2001.[133]

The Texas approach to implementing competition has been cited as a good model for restructuring. The decision to deal with wholesale issues at the outset by leveling the playing field for equal transmission access "promises to create a strong retail market," according to one energy consultant.[134] A spokesperson for another energy company, however, believes that a serious flaw in the restructuring plan is the local control of metering and billing until 2004.[135]

With regard to renewables, a new rule mandates the building of 2 gigawatts of new capacity fueled by renewable sources by 2009. Between now and 2009 the rule requires the following: 400 megawatts by 2003, an additional 450 megawatts by 2005, another 550 megawatts by 2007, and an additional 600 megawatts by 2009. January 1, 2002, will mark the beginning of a Renewable Credits Trading Program in the State, which will continue until 2019. Retailers with insufficient credits will be penalized $50 per megawatthour or 200 percent of the average cost of traded credits of the year.[136]

Massachusetts

On November 27, 1997, HB 5117, the Electric Utility Restructuring Act, was signed by Governor Paul Cellucci to restructure the industry in Massachusetts. The law basically affirmed the PUC restructuring order of 1996. The Restructuring Act mainly affects the Commonwealth's eight investor-owned distribution companies, which supply 87 percent of the electricity in Massachusetts.[137] Retail access was required by March 1998, and a simultaneous rate cut of 10 percent to be followed 18 months later by an additional 5 percent cut was made law. Municipal utilities have the option to participate.[138] Additionally, the divestiture of generation assets was encouraged.[139] In 1996, Massachusetts had the eighth highest electricity rates in the Nation, which were most certainly a consideration in enacting the legislation the following year. In 1998, the rates in the Commonwealth were the ninth highest in the country. Between 1996 and 1998, the nonutility share of capability increased from 16 percent to 67 percent as utility divestitures took place. So far, however, the number of customers that have switched is not high. A slowly increasing standard offer rate (described below) could lead to increases in customers in the future.[140]

Three generation service options are available to consumers: (1) Standard Offer Service, provided by distribution companies; (2) Default Service, provided by distribution companies; and (3) Competitive Generation Service, provided by competitive suppliers. The price the customer pays for generation service is dependent on the type of service that the customer receives.

Standard Offer Service is a transition generation service available through 2004 to each distribution company's customers of record. The price of the Standard Offer Service is set in advance and will increase gradually. As examples, the Standard Offer Rates for the Boston

[132] U. S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/apr7_00.html.
[133] U. S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/jan21_00.html.
[134] U. S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/feb25_00.html.
[135] *Ibid.*
[136] U.S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/jan7_00.html.
[137] *Foster Electric Report*, No. 176 (October 20, 1999), p. 3.
[138] States' Electric Restructuring Activities Update, Florida Public Service Commission, http://www.psc.state.fl.us/general/publications/restruc.htm.
[139] Energy Information Administration, "Status of State Electricity Industry Restructuring Activity as of May 2000," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html.
[140] *The Energy Report* (Arlington, VA: Financial Times Energy, January 3, 2000), p. 5.

Edison Company and the Cambridge Electric Light Company rose from 3.69 cents and 3.5 cents per kilowatthour to 4.5 cents and 3.8 cents per kilowatthour, respectively, from 1999 to 2000.[141] A customer that did not select a competitive supplier as of March 1, 1998, automatically was placed on the Standard Offer Service. (Customers who move into a distribution company's service territory after March 1, 1998, are not eligible to receive the Standard Offer—these customers are placed on Default Service until they select a competitive supplier.) In general, once customers select a competitive supplier, they are no longer eligible to return to the Standard Offer Service. Exceptions include (1) low-income customers who can return at any time, (2) residential and small commercial and industrial customers who return within 120 days of deleting a supplier (This option was available only until March 1, 1999.), and (3) customers participating in a municipal aggregation program who return within 180 days of joining the program. The rates for the Standard Offer Service are regulated by the Department of Telecommunications and Energy (DTE) and were set at levels that provided a 10 percent overall bill reduction to customers receiving the Standard Offer Service. The level of the overall bill reduction for the Standard Offer customers increased to 15 percent on September 1, 1999.

Default Service is the generation service provided by distribution companies to those customers who are not receiving either Competitive Generation or Standard Offer Service. Customers who moved into a distribution company's service territory after March 1, 1998, received Default Service until they selected a competitive supplier. Prices for Default Service are regulated by the DTE and may not exceed the average market price for electricity in New England.

Competitive Generation Service will be provided by competitive suppliers and electricity brokers that have been licensed by the DTE. A competitive supplier is defined as licensed to sell electricity and related services to customers. As of May 2000, 33 authorized competitive suppliers/electricity brokers were located in Massachusetts. An electricity broker is an entity that is licensed to facilitate or otherwise arrange for the purchase and sale of electricity and related services to customers, but is not licensed to sell electricity to customers. An applicant for a competitive supplier or electricity broker license must demonstrate, among other things, the financial and technical capability to provide the applicable services. Prices for Competitive Generation Service will be set by the competitive electricity marketplace; these prices will not be regulated by the DTE. Customers receiving generation service from a competitive supplier have two billing options: (1) complete billing, where a customer receives a single bill from the distribution company, including charges for generation service, and (2) pass-through billing, where a customer receives two bills—one from the distribution company for non-generation charges and another from the competitive supplier for generation service charges.[142]

An assessment of the first year of electric utility industry restructuring in Massachusetts shows that the largest accomplishment was the mandated reduction in overall customer bills by 10 percent. However, little retail competition has resulted due to the low Standard Offer. In fact, between February and March 2000, the number of customers buying competitive power dropped by 1,100. Of the 2.5 million electric accounts in the Commonwealth, only 7,302 are buying power competitively.[143]

Energy Commissioner David O'Connor has stated that the problem lies in the region's volatile wholesale power market, which has seen significant price spikes. High wholesale prices have led to high retail prices and consequently, commercial and industrial customers, whose competitive power contracts are expiring, are opting to go back to low-price utility service.[144]

To address the problem, the DTE has proposed two market-based pricing options to remove the incentive for customers to return to default service. The first offers customers a fixed price for 6-month periods. It would be available to all customers who are already on default service when the 6-month period begins, or who moved into the service territory after the period begins. The price would be based on the average monthly wholesale

[141] Initially the Standard Offer rates for each of the Massachusetts distribution companies approved by the Department of Telecommunications and Energy was equal to 2.8 cents per kilowatthour. The rate for each of these companies remained at 2.8 cents for the remainder of 1998, with two exceptions: (1) Boston Edison increased its Standard Offer rate to 3.2 cents on June 1, 1998, concurrent with the completion of the divestiture of its non-nuclear generating units; and (2) Massachusetts Electric Company increased its Standard Offer rate to 3.2 cents on September 1, 1998, concurrent with the completion of the divestiture of New England Power Company's non-nuclear generating units.

[142] Massachusetts Department of Telecommunications and Energy, Electric Restructuring in Massachusetts, http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm.

[143] *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 8.

[144] *Ibid.*

price that each utility pays for supply. The second option would allow default service price to change monthly, based on the monthly wholesale prices that each utility pays for its default service supply. This option would be available to customers who begin receiving the service after the start of the 6-month period and who were previously receiving their electricity from a competitive supplier.[145]

Paul Gromer, an attorney with the Boston-based Peregrine Energy Group, which represents the independent power marketers operating in the Commonwealth, states the problem lies in the fact that one default service rate exists for all customers. He argues that this creates cross-subsidization and inaccurate pricing signals. He contrasts what is happening in Massachusetts with the way Connecticut, Pennsylvania, New Jersey, California, and Maine have offered different rates for different customer classes.[146]

Major changes are, however, taking place even though competitive supply is hardly pervasive throughout the Commonwealth. For example, utility companies made significant progress in divesting their power plants and power supply contracts. The generation portion of the electric industry is now virtually all owned by independent power producers. This extensive sale of power plants has significantly reduced the stranded cost obligations that would have been facing ratepayers. Massachusetts had awarded stranded costs if conforming utilities had demonstrated that they had divested all non-nuclear generation and attempted to mitigate all other costs. So far, approximately $2 billion of the total $6 billion that will eventually be paid has been transferred. Securitization then becomes permissible.[147] If a utility had been unwilling to divest its generation, the DTE would have determined the level of stranded costs.

ISO New England received conditional FERC approval on June 25, 1997. Utilities in all six New England States created the ISO through a voluntary agreement.[148] Additionally, proposed construction of more than 30 gigawatts of new power plants has been announced across the region, prompted by restructuring legislation enacted in most of the New England States. While not all proposals will come to fruition, it is likely that the increased competition from these new plants will force some of the existing, less efficient plants into retirement. Most of the new capacity will be fueled by natural gas and other low emission fuels; therefore air pollution should be lowered and customers will have the option to buy greener power from sources close to home.

With respect to public benefit programs, distribution companies must offer low income discounts. A Renewable Energy Trust Fund was established with a fee of 0.125 cents per kilowatthour in 2000. Also, a charge of 0.33 cents per kilowatthour has been established for funding energy efficiency programs. The fee will be phased down to 0.25 cents per kilowatthour in 2002.

A renewable portfolio standard is mandated, and hydropower is considered to be a renewable energy source. One percent of sales must be from new renewables by 2003. This rises by 0.5 percent each year until 2009 and then increases 1 percent per year thereafter until ended by the Division of Energy Resources.[149]

Pennsylvania

In 1996, the average revenue per kilowatthour in Pennsylvania was 7.96 cents;[150] in 1998, it was 7.86 cents. In both years, Pennsylvania had the eleventh highest average electricity price among the 50 States and the District of Columbia. Like California and Massachusetts, Pennsylvania falls into the camp of relatively high-priced States that have been somewhat aggressive in pursuing restructuring.

In terms of numbers of customers that have switched suppliers, Pennsylvania's restructuring program is the most successful in the Nation. Governor Tom Ridge signed the Electricity Generation Customer Choice and Competition Act into law on December 3, 1996. The law basically separates the generation of electricity from the services of transmitting and distributing it. The law called for a phase-in of retail choice with one-third eligible to choose by January 1998, another third by January 1999, and the remaining third by January 2000. Therefore, all customers in Pennsylvania can now choose

[145] *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 1.

[146] *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 9.

[147] The Act authorizes the Massachusetts Industrial Finance Agency to issue "electric rate reduction revenue bonds," to finance the buy-out by electric companies of purchased power contracts with above-market rates.

[148] Florida Public Service Commission, "States' Electric Restructuring Activities Update," http://www.psc.state.fl.us/general/publications/restruc.htm.

[149] *Ibid.*

[150] Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999), p. 234.

the generator of their electricity, but they are still required to purchase the transmission and distribution components of their electricity from the local supplier. All utilities subject to the separation requirements were required to file their restructuring plans with Pennsylvania's Public Utilities Commission (PUC) in 1997. The PUC has established industry groups to provide recommendations on areas of concern that have arisen in the restructuring process. These areas include education, information and billing, universal service, conservation, reliability, direct retail access implementation scheduling, metering competitive safeguards, interaction between suppliers and utilities, and taxes. A multimedia consumer education campaign was launched by the Pennsylvania Electric Choice Program to educate consumers about their ability to shop for a competitive supplier. Included in the campaign were television and radio advertisements as well as a four-page newspaper insert.[151]

With regard to stranded costs, the PUC is authorized to determine the level of stranded costs that each utility is permitted to recover. Cost shifting between customers as a result of stranded cost recovery is prohibited. The costs can be recovered through a non-bypassable competitive transition charge (CTC) that will be reviewed and adjusted annually for each customer who elects to receive service from an alternative generation supplier. The CTC will be collected by utilities over a maximum period of 9 years, unless the PUC approves another time frame. California, by contrast, authorized a collection period of only 4 years.

The Competition Act encourages market participants to coordinate their plans and transactions through an ISO or functional equivalent. Electric utilities are permitted to divest themselves of facilities or to reorganize their corporate structures, but unbundling of services is required. Additionally, public benefits programs are funded by an energy surcharge to provide programs for low-income assistance, energy conservation, and other public purposes at the existing funding level.[152]

As a result of the new law encouraging outsiders to set up business within the Commonwealth (unlike Florida whose Supreme Court recently reaffirmed restrictions on merchant plants), interesting developments have occurred. For example, the largest wind farm in the eastern United States is now in Pennsylvania. GreenMountain.com, which completed the eight-turbine project in April 2000, is betting that customers will pay a slight premium to switch to power that is cleaner than the traditional source of Pennsylvania's electricity—coal.[153]

Today, 52 suppliers are licensed to sell their generation in the Commonwealth. A survey from the Office of Consumer Advocate reports that 408,414 (8 percent) of Pennsylvania's residential electricity customers have switched utility providers. The survey also noted that 95 percent of electricity customers are aware of their options to switch to alternative suppliers under the law. Of those who have switched, approximately 20 percent have opted for a green power choice.[154] In the PECO service area in southeastern Pennsylvania, 15 percent of residential customers, 30 percent of commercial customers, and 62 percent of industrial customers have switched suppliers.[155] Twenty-six percent of Duquesne Light's residential customers switched their supplier. Technically, with the recent completion of Duquesne Light's sales of its generating assets to Orion Power Holdings,[156] all customers have a new supplier of electricity. The 26-percent citation represents those customers who actively sought an alternative supplier. Duquesne Light provides service in the Greater Pittsburgh area.

One of the keys to Pennsylvania's successful transition to a competitive retail marketplace may have been its pilot program. The program provided an incentive to participate by guaranteeing a 10- to 13-percent discount off the electric distribution company charge for all classes of customers while establishing a generation credit that allowed customers to obtain electricity supply at 5 to 20 percent below the credit. "As a result, the pilot was oversubscribed and the PUC and the electric distribution companies had an opportunity to work out problems in the transition to competition," according to Sandra Barber of the National Energy Team.[157]

[151] U.S. Department of Energy, Electric Utility Restructuring Weekly Update (February 18, 2000), http://www.eren.doe.gov/electricity_restructuring/weekly/feb18_00.html.

[152] Florida Public Service Commission, "States' Electric Restructuring Activities Update," http://www.psc.state.fl.us/general/publications/restruc.htm.

[153] "GreenMountain.com Makes Pitch for Clean Energy," *The Wall Street Journal* (May 1, 2000), p. A36.

[154] *Ibid.*

[155] The Pennsylvania Electric Choice Program, http://www.electrichoice.com/public/pdf/elecchart.pdf.

[156] *The Energy Report* (Arlington, VA: Financial Times Energy, May 8, 2000), p. 15.

[157] Anne Millen Porter, "Why Pennsylvania Might Be the Only Game in Town," Purchasing (July 16, 1998).

Kentucky

In December 1999, Kentucky's Special Task Force on Electricity Restructuring released its findings and recommendations. It found that "there is no compelling reason at this time for Kentucky to move quickly to restructure. Despite the prospects of Congressional legislation to mandate restructuring, actions taken by 24 States and the District of Columbia to restructure, and the fact that some of those States are geographically contiguous to Kentucky, there are obvious advantages for Kentucky adopting a wait-and-see approach to electricity restructuring. Representatives from other States that have restructured as well as experts in the field of electricity restructuring indicate that Kentucky is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains. Most of Kentucky's generation is coal-fired and its generators are close to coal fields which are among the cheapest fuel sources. Also, there has been relatively little construction of generating capacity recently, which has kept the Commonwealth's collective rate base low. A wait-and-see approach allows Kentucky to monitor the progress of restructuring in other States and to develop options that protect Kentucky's existing low rates for electricity."[158]

In 1998, when the average revenue per kilowatthour in Kentucky was 4.16 cents, only Idaho and Washington had lower electricity rates. Unlike California, Massachusetts, and Pennsylvania, Kentucky has no compelling price pressure to restructure. Therefore, the Commonwealth has no retail competition and no competitive supplier activity. The only recent action of note was a Public Service Commission Order in April 1999 to reduce rates for Kentucky Utilities and Louisville Gas and Electric subsidiaries. The order calls for a $52 million rate reduction under a performance-based rate making approach.[159]

Because Kentucky has had no restructuring activity, no stranded cost provisions are in place.

Issues Under Consideration

The current issues faced by the States are varied based on the wide array of associated circumstances. Some areas of concern, however, are similar across State lines, for example:

- Remedying the loss of tax base for local authorities
- Generating renewable power and provisions for net metering
- Evaluating performance-based ratemaking
- Providing non-discriminatory access to all electric power suppliers
- Setting standards of conduct for suppliers and utility affiliates
- Taking environmental issues into consideration
- Ensuring reliability in supplies and designation of supplier of the last resort during transition
- Establishing consumer protection programs
- Determining the role of public power utilities in promoting competition.[160]

The following chapter examines in more detail the role of recent mergers, acquisitions, and power plant divestitures of IOUs in restructuring the electric power industry.

[158] Kentucky Association of Electric Cooperatives, Inc., http://www.kaec.org/stand/elecrestructuring.htm.
[159] Energy Information Administration, "Status of Electricity Industry Restructuring by State," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html.
[160] Energy Information Administration, *Electric Power Annual 1999, Volume I*, DOE/EIA-0348(99)/1 (Washington, DC, August 2000).

9. Mergers, Acquisitions, and Power Plant Divestitures of Investor-Owned Electric Utilities

In response to increased competition in power generation, investor-owned utilities (IOUs) have engaged in a wave of mergers and acquisitions during the past decade, resulting in some very large IOUs. In contrast, some IOUs have exited the power generation business by selling their generation assets to an independent power producer (IPP), or by transferring them to an unregulated subsidiary within their company. The purpose of these contrasting strategies is to improve and solidify a position in the new competitive industry. It is too early to determine, however, the effectiveness of these strategies on the industry and their benefits to electricity customers.

Recent mergers are classified broadly into two categories, each category representing a fundamentally different reason for merging. The first category includes mergers between IOUs or between IOUs and IPPs. These mergers are motivated by the desire to increase power generation capacity and/or transmission and distribution capacity and in general become a larger electric utility. Most utility executives take the position that to compete successfully in today's electricity market a company must be relatively large.

The second category includes mergers between electric utilities and natural gas companies. Companies entering into these types of mergers are seeking to become a regional or even a national company that produces, transports, and markets electricity and natural gas. These are called convergence mergers because they represent the increasing number of companies that own both electricity and natural gas assets and are active in both industries. Each of these categories of mergers is described followed by an examination of recent divestitures of power generation assets by IOUs.

Mergers and Acquisitions Between IOUs and IPPs

From 1992 to April 2000, 35 mergers or acquisitions have been completed between IOUs or between IOUs and IPPs. Twelve mergers have been announced and are now pending stockholder or Federal and State government approval (Table 14).[161] The size of IOU mergers, in terms of value of assets, is also increasing. Between 1992 and 1998, only four mergers were completed in which the combined assets of the companies in each merger were greater than $10 billion. More recently, eight mergers completed in 1999 or 2000, or pending completion, each have combined assets greater than $10 billion.

One of the effects of this wave of mergers is that there are fewer operating electric utilities. In 1992, 172 operating utilities owned generation capacity in the United States. By the end of 2000, the number of operating utilities owning generation capacity will decrease to an estimated 141 (Table 15). Power plant divestitures, discussed later in the chapter, have also reduced the total number of IOUs that own generation capacity.

The majority of operating electric utilities are wholly-owned subsidiaries of public utility holding companies.[162] The effect of mergers on consolidation of the industry is more evident when ownership capacity is aggregated by holding companies. In 1992, there were 70 electric holding companies owning 78 percent of the IOU-held generation capacity. By the end of 2000, the number of electric holding companies will decrease to 53, and the generation capacity they own will increase to about 86 percent of the total IOU-owned capacity, primarily because of mergers and acquisitions. This statistic suggests that relatively large companies are becoming even larger.

Although many electric utilities see a need to grow through mergers, others do not. Of 82 electric utilities (53 electric utility holding companies and 29 independent electric utilities) in 2000 (Table 15), 56 (approximately 60 percent) have not been involved in a merger since 1992 and have not announced plans to merge. This suggests that even though the merger trend is strong, most IOUs believe consolidation is not necessary to

[161] Investor-owned utility acquisitions of foreign companies or non-energy related companies are not included in this analysis.

[162] In some cases a holding company will also be a subsidiary of another holding company. The number of holding companies cited in this report refers to the highest level holding company.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**American Electric Power Co., Inc.** (a registered holding company for AEP Generating Co., Appalachian Power Co., Columbus Southern Power, Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co.)	**Central and South West Corp.** (a registered holding company for Central Power and Light Co., Public Service Co. of Oklahoma, Southwestern Electric Power Co., and West Texas Utilities Co.)	**American Electric Power Co., Inc.** (Central and South West will be a wholly-owned subsidiary)	VA, WV OH, IN MI, KY TN, TX OK, LA AR	AEP: $19.5 CSW: $13.7 Total: $33.2	Under regulatory review.
	Consolidated Edison, Inc. (a holding company for Consolidated Edison Co. of New York, Inc., and Orange and Rockland Utilities)	**Northeast Utilities** (a holding company for Connecticut Light & Power, Public Service Co. of New Hampshire, and Western Massachusetts Electric Co.)	**Consolidated Edison, Inc.** (Northeast Utilities will be a subsidiary)	NY, CT, MA, NH	Consolidated Edison: $14.4 Northeast: $10.4 Total: $24.8	Under regulatory review. Received shareholder approval 4/14/00.
	Carolina Power & Light Co. (an operating utility)	**Florida Progress Corp**. (a holding company for Florida Power Corp.)	Unknown	FL, NC, SC	CP&L: $8.3 Florida: $6.2 Total: $14.5	Under regulatory review.
	UtiliCorp United (a holding company)	**St. Joseph Light & Power** (an operating utility)	**Utilicorp** (St. Joseph will keep its name and become a wholly-owned subsidiary)	MO, KS CO, WV	Utilicorp: $6.0 St. Joseph: $0.3 Total: $6.3	Under regulatory review.
	New Century Energies (a registered holding company for Public Service Co. of Colorado, Southwestern Public Service Co., and Cheyenne Light, Fuel, & Power)	**Northern States Power** (a holding company)	**Xcel Energy** (unknown if New Centuries and Northern States Power operate as subsidiaries)	NM, OK TX, WY AR, MI MN, SD ND, WI	New Century: $7.7 NSP: $7.4 Total: $15.1	Received FERC approval. Under review by States.
	UtiliCorp United (a holding company)	**Empire District Electric Co.** (an operating utility)	Unknown	MO, CO KS, WV OK, AR	Utilicorp: $6.3 Empire District: $0.7 Total: $7.0	Under regulatory review.
	Sierra Pacific Resources (a holding company for Sierra Pacific Power and Nevada Power)	**Portland General Electric** (a subsidiary of ENRON Corp.)	**Sierra Pacific Resources** (Portland General Electric will be a subsidiary)	NV, CA, OR	Sierra: $4.6 Portland: $3.2 Total: $7.8	This acquisition was announced 11/99.
	Energy East (a holding company for New York Electric & Gas)	**CMP Group** (a holding company for Central Maine Power)	**Energy East** (CMP Group will be a wholly-owned subsidiary)	MA, MI NY, NH	Energy East: $4.9 CMP Group: $2.3 Total: $7.2	Obtained FERC approval 4/10/00.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**Unicom Corporation** (a holding company for Commonwealth Edison)	**PECO Energy Co.** (a registered holding company for Susquehanna Power Co.)	**Exelon** (A new holding company)	IL, PA	Unicom: $30.2 Peco: $12.0 Total: $42.2	Under regulatory review.
	PowerGen plc (a foreign-owned power producer)	**LG&E Energy Corp.** (a holding company for Louisville Gas & Electric and Kentucky Utilities)	**PowerGen** (LG&E will be a wholly-owned subsidiary)	KY, VA	Not available because PowerGen is a foreign company.	This acquisition was announced in 2/00.
	Cap Rock Energy Corporation (electric cooperative)	**Citizens Utilities Company** (an operating utility)	**Cap Rock Energy Corporation**	AR, VT	Not Applicable	Cap Rock is an electric cooperative that is in the process of converting to an investor-owned utility. Cap Rock is purchasing Citizens Utilities distribution assets in Arizona and Vermont.
	Kauai Island Electric Cooperative (an electric cooperative)	**Citizens Utilities Company** (an operating utility)	**Kauai Island Electric Cooperative**	HI	Not Applicable	Citizens Utilities is selling its Hawaii Electric distribution business to Kauai Island.
Completed in 2000	**Berkshire Hathaway (et. al.)** (an investor group)	**MidAmerican Energy Holdings Company** (a holding company for MidAmerican Energy)	**Berkshire Hathaway** (MidAmerican will be a subsidiary)	IA, KS	Unknown	Berkshire Hathaway is an investment company. The acquisition was completed in 3/00. MidAmerican and CalEnergy merged in 1999.
	Laurel Hill Capital Partners, LLC (an investment company)	**TNP Enterprises Inc.** (a holding company for Texas-New Mexico Power Company)	**TNP Enterprises** will continue to exist	TX, NM	Unknown	This acquisition represents a change in ownership of TNP. No information was given about creating a new corporation.
	National Grid Group PLC (a foreign company)	**New England Electric Systems (NEES)** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	**National Grid Group** (NEES will be a wholly-owned subsidiary)	VT, NH MA	Not available because National Grid Group is a foreign company.	Completed.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 2000 (Continued)	**New England Electric System** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	**Eastern Utility Associates** (a registered holding company for Blackstone Valley Electric Co., Newport Electric Corp., Eastern Edison Co., EUA, and Ocean State Corp.)	**New England Electric System** (EUA will be a wholly-owned subsidiary)	MA, RI VT, NH	NEES: $5.3 EUA: $1.3 Total: $6.6	Completed.
	Allegheny Energy, Inc. (a registered holding company)	**West Virginia Power** (an operating utility)	**Allegheny Energy** (West Virginia Power will be a subsidiary)	PA, WV, OH, MD	Allegheny: $6.7 West Virginia: $ .1 Total: $6.8	West Virginia Power is a small electric and gas distribution company.
Completed in 1999	**Nevada Power** (an operating utility)	**Sierra Pacific Resources** (a holding company for Sierra Pacific Power Co.)	**Sierra Pacific Resources** (Nevada Power will be a wholly-owned subsidiary)	NV, CA	Nevada Power: $2.6 Sierra Pacific: $2.0 Total: $4.6	Completed.
	AES Corporation (an independent power producer)	**CILCORP** (a holding company for Central Illinois Light Co.)	**AES** (CILCORP will be a wholly-owned subsidiary)	IL	AES: $10.0 CILCORP: $1.3 Total: $11.3	Completed.
	BCE Energy (a holding company for Boston Edison)	**Commonwealth Energy** (a holding company for Cambridge Electric Light Co., Canal Electric Co., and Commonwealth Electric Co.)	**NSTAR** (a new holding company; Boston Edison and Commonwealth Energy will be subsidiaries)	MA	BCE: $3.2 Commonwealth: $1.5 Total: $4.7	Completed.
	Scottish Power PLC (a foreign company)	**PacifiCorp** (an operating utility)	Unknown (a new holding company; PacifiCorp will be a subsidiary)	UT, OR, WY, WA, ID, MT, CA	Not available because Scottish Power is a foreign company.	Completed.
	CalEnergy Co., Inc. (an independent power producer)	**MidAmerican Energy Holding Co.** (a holding company for MidAmerican Energy Co.)	**MidAmerican Energy Holding** (CalEnergy will be a subsidiary)	IA, KS	CalEnergy: $7.5 MidAmerican: $4.3 Total: $11.8	Completed.
	Consolidated Edison, Inc. (a holding company for Consolidated Edison Co. of New York, Inc.)	**Orange and Rockland Utilities** (an operating utility)	**Consolidated Edison, Inc**. (Orange and Rockland will be a wholly-owned subsidiary)	NY	ConEd: $14.4 O&R: $1.3 Total: $15.7	Completed.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1998	**Delmarva Power & Light Co.** (an operating utility)	**Atlantic Energy** (a holding company for Atlantic City Electric Co.)	**Conectiv** (a new registered holding company)	MD, DE VA, NJ	Delmarva Power: $3.0 Atlantic: $2.7 Total: $5.7	Completed.
	LG&E Energy (a holding company for Louisville Gas & Electric Co.)	**KU Energy** (a holding company for Kentucky Utilities)	**LG&E Energy** (KU Energy will be dissolved)	KY, VA TN	LG&E: $3.0 KU Energy: $1.7 Total: $4.7	Completed.
	WPL Holding, Inc. (a holding company for Wisconsin Power & Light)	**IES Industries** (a holding company for IES Utilities and Interstate Power, an operating utility)	**Alliant Energy** (a new holding company)	WI, IA MN, IL	WPL Holding: $1.9 IES: $2.5 Interstate: $0.6 Total: $5.0	Completed.
	Wisconsin Energy (a holding company for Wisconsin Electric Power Co.)	**ESELCO** (a holding company for Edison Sault Electric Co.)	**Wisconsin Energy Company** (ESELCO will be a wholly-owned subsidiary)	WI, MI	Wisconsin: $5.0 ESELCO: $0.1 Total: $5.1	Completed.
	WPS Resources (a holding company for Wisconsin Public Service Corp., Wisconsin River Power Co.)	**Upper Peninsula Energy** (a holding company for Upper Peninsula Power Co.)	**WPS Resources** (Upper Peninsula Energy will cease to exist)	WI, MI	WPS: $1.1 Upper Peninsula: $0.1 Total: $1.2	Completed.
Completed in 1997	**Ohio Edison Co.** (an operating utility; Ohio Edison also owns Pennsylvania Power Co.)	**Centerior Energy** (a holding company for Cleveland Electric Illuminating Co. and Toledo Edison Co.)	**FirstEnergy** (a new registered holding company)	OH	Ohio Edison: $8.9 Centerior: $10.2 Total: $19.1	Completed.
	Public Service Co. of Colorado (an operating utility and a holding company for Cheyenne Light, Fuel, and Power)	**Southwestern Public Service Co.** (an operating utility)	**New Century Energies** (a new registered holding company)	CO, TX NM, OK KS	PS Co. of CO: $4.6 Southwestern: $2.0 Total: $6.6	Completed.
	Union Electric Co. (an operating utility)	**CIPSCO** (a holding company for Central Illinois Public Service Co.)	**Ameren** (a new registered holding company)	MO, IL	Union: $6.8 CIPSCO: $1.8 Total: $8.6	Completed.
	Pacific Gas & Electric Corp. (a holding company for Pacific Gas & Electric)	**U.S. Generating Co. (USGen)** (an independent power producer)	**Pacific Gas & Electric Corp.** (USGen will be an unregulated affiliate of PG&E)	USGen has plants in numerous States	USGen: $5.0	PG&E acquired 50 percent in USGen. At the time, USGen had ownership in 17 electric generating facilities operating in the United States.
Completed in 1996	**New England Electric Systems** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	**Nantucket Electric** (a small electric distribution company)	**New England Electric System** (Nantucket Electric is a subsidiary)	VT, NH MA	NEES: $5.1 Nantucket: $0.1 Total: $5.2	Completed.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1995	**City of Groton, CT**	**Bozrah Light and Power**	Unknown	CT	Unknown	Completed.
	Delmarva Power and Light	**Conowingo Power Co.**	**Delmarva Power and Light**	DE, MD, VA	Delmarva Power: $2.9 Conowingo: $0.1 Total: $3.0	Completed.
	Midwest Resources (a holding company for Midwest Power Systems)	**Iowa-Illinois Gas and Electric** (an operating utility)	**MidAmerican Energy** (a holding company and operating utility)	IA, SD, IL	Midwest: $2.6 Iowa: $1.9 Total: $4.5	Completed.
Completed in 1994	**PSI Resources** (an operating utility)	**Cincinnati Gas & Electric** (an operating utility)	**CINergy** (PSI Resources and Cincinnati are wholly-owned subsidiaries)	IN, OH, KY	PSI Resources: $2.9 Cincinnati: $5.2 Total: $8.1	Completed.
Completed in 1993	**Citizens Utilities Co.** (an operating utility)	**Franklin Electric** (an operating utility)	**Citizens Utilities** (Franklin Electric ceased to exist)	AZ, HI, VT	Citizens: $2.6 Franklin: $0.8 Total: $3.4	Completed.
	IES Utilities Inc. (a holding company)	**Iowa Electric Light & Power and Iowa Southern Utilities**	**IES Industries** (IES Utilities, Iowa Electric, and Iowa Southern are subsidiaries)	IA	Total: $1.8	Completed.
	Texas Utilities (a holding company)	**Southwestern Electric Service Co.** (an operating utility)	**Texas Utilities** (Southwestern Electric is a subsidiary)	TX	Total: $20.9	Completed.
	Entergy Corp. (a holding company)	**Gulf States Utilities** (a holding company)	**Entergy Corp.** (Gulf States is a wholly-owned subsidiary)	AR, TN, LA, TX, MS, NY	Entergy: $14.2 Gulf States: $7.2 Total: $21.4	Completed.
Completed in 1992	**Connecticut Light & Power**	**Fletcher Electric Light Co.**	**Connecticut Light and Power**	CT	Total: $6.2	Completed.
	Iowa Public Service Co.	**Iowa Power Co.**	**Midwest Power**	IA, SD	Total: $2.6	Completed.
	Kansas Power & Light	**Kansas Gas & Electric**	**Western Resources**	KS	Total: $5.2	Completed.
	Indiana Michigan Power Co.	**Michigan Power Co.**	**Indiana Michigan Power Co.**	IN, MI	Total: $4.3	Completed.
	Unitil Corp.	**Fitchburg Gas & Electric**	**Unitil Corp.**	NH	Total: $0.2	Completed.
	Northeast Utilities	**Public Service of New Hampshire**	**Northeast Utilities**	NH, CT, MA	Total: $10.6	Completed.

Table 15. Comparison of the Number of Investor-Owned Electric Utilities Owning Generation Capacity, 1992 and 2000

Company Category	1992			2000 (Estimated)		
	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)
Utility that is a Subsidiary to a Holding Company.	113	70	(78%) 422.1	112	53	(86%) 384.5
Independent Utility	59	--	(22%) 120.3	29	--	(14%) 60.6
Total	**172**	**70**	**(100%) 542.4**	**141**	**53**	**(100%) 445.1**

[a]The number of utilities reported here does not match the number of utilities reported in Chapter 2 for the following reasons: (1) these data include IOUs that own power generation capacity, whereas the data reported in Chapter 2 include IOUs that operate power plants; (2) some utilities operate transmission and distribution systems only and are not included here; and (3) these data exclude Alaska and Hawaii.

Notes: • The 2000 data include the effects of pending mergers on consolidation of ownership. It is assumed that all pending mergers will be completed by 2000. • Also, the 2000 data include the effects of generation asset divestitures on consolidation of ownership. It is assumed that all divestitures where a buyer has been announced will be completed by 2000. • Holding companies were identified from the following documents: U.S. Securities and Exchange Commission Financial and Corporate Reports, "Holding Companies Registered Under the Public Utility Holding Company Act of 1935 as of October 1, 1995, as of December 1, 1996, and as of June 1, 1998," and "Holding Companies Exempt from the Public Utility Holding Company Act of 1935 Under Section 3(a) (1) and 3(a) (2) Pursuant to Rule 2 Filings or By Order as of August 1, 1995 and as of November 1, 1997."

Sources: Energy Information Administration, Forms EIA-860, "Annual Electric Generator Report;" EIA-860A, "Annual Electric Generator Report – Utility;" and EIA-861, "Annual Electric Utility Report."

remain competitive in the industry in spite of the fact that those companies choosing to merge are acquiring a larger share of the industry's assets.

The absolute number of companies provides insight into consolidation trends, but concentration of generation capacity ownership is perhaps more indicative of consolidation.[163] As a measure of consolidation of the IOU sector, concentration indicates the extent to which total capacity ownership is dispersed among companies. The data suggest that generation capacity owned by IOUs has been concentrated in the hands of a few companies, and that mergers and acquisitions are increasing the concentration of ownership within the IOU sector. In 1992, the 10 largest utilities, ranked according to generation capacity, owned 36 percent of all IOU generation capacity; by the end of 2000 the 10 largest companies' share will increase to an estimated 51 percent (Figure 29). Evidence of consolidation among the 20 largest companies is even more compelling. In 1992 the 20 largest companies owned 58 percent of total IOU generation capacity; by the end of 2000 their share is expected to increase to approximately 72 percent.

Mergers and acquisitions also cause consolidation of ownership of the Nation's transmission and distribution systems. However, the outcome of this trend is unclear because many utilities may transfer ownership of their transmission system to regional transmission organizations in compliance with the Federal Energy Regulatory Commission's (FERC's) Order 2000.

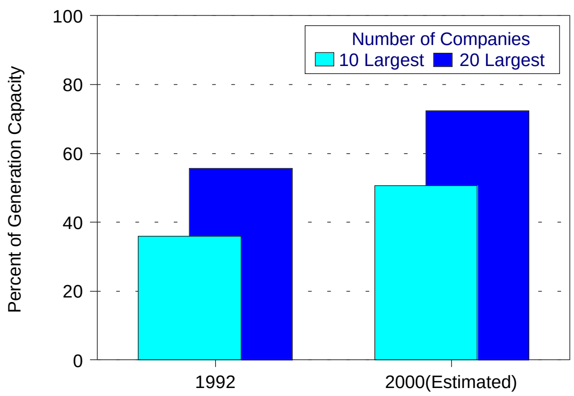
Reasons for Mergers and Acquisitions Among Electric Utilities

Most, if not all, utility executives who have directed their companies through mergers, argue that electric utilities must be relatively large to be competitive.[164] This position underlies most of the mergers and acquisitions recently completed between IOUs. Why does size

[163] Measures of concentration are sometimes used to identify the potential for a firm to exercise market power in a particular product market. Measuring concentration is problematic in the electric power industry due to the difficulty in defining relevant markets. In this report, measures of concentration were not developed for a particular electricity market. Instead, the term concentration is used broadly to suggest that the recent wave of mergers is responsible for the increase in size of many IOUs.

[164] For example, the CEO of New Century Energies, when discussing the merger between New Century Energies and Northern States Power, said "The merger provides both the combined company and its operating units with the scale necessary to remain competitive in a changing industry marketplace," Press Release, *New Century Energies* (March 1999).

Figure 29. Concentration of Ownership of Investor-Owned Utility Generating Capacity, 1992 and 2000



Notes: •The 10 largest companies are public utility holding companies that own one or more operating electric utilities. •The 2000 data assume that all pending mergers will be completed by year-end 2000. •Capacity owned by subsidiaries of IOUs was not counted when computing rankings.

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

matter? The thinking is that larger companies are able to achieve economies of scale. By combining resources and eliminating redundant or overlapping activities, larger companies hope to benefit from increased efficiencies in procurement, production, marketing, administration, and other functional areas that smaller companies may not be able to achieve. For example, a larger company, because of a high volume of purchases, may be able to negotiate a lower price from its fuel supplier than would be available to a smaller company. Cost savings resulting from increased efficiency can be passed to the utility's customers through lower electricity rates.

Whereas utility executives argue that a merger or acquisition will improve the efficiency of the combined company, experience indicates that efficiency improvements are not guaranteed. One study reported that only 15 percent of mergers and acquisitions achieved their expected financial objectives.[165] Incomplete or underdeveloped plans to integrate the companies was noted as a major factor for not achieving the objectives.

A company's strategic objectives are also factors in the decision to merge. Does the merger complement or enhance the strategic objectives of the company is a question asked by company executives in identifying merger partners. Strategic objectives are company specific and depend upon the merging companies' particular circumstances. Building on core competencies, securing more customers, consolidating transmission and distribution facilities, diversifying power generating capability, and acquiring additional managerial and technical expertise are mentioned often as reasons. These strategic reasons, however, relate to the desire to remain competitive in the rapidly changing electricity industry.

Convergence Mergers

Increased competition has pressured electric utilities and natural gas companies to combine operations in order to become more efficient, to diversify products, to share expertise and experience in energy markets, and to take advantage of the growing use of natural-gas-fired power plants. Combining electric utilities and natural gas companies is called convergence of the industries, and many companies that once sold only electricity or natural gas now sell both electricity and natural gas, or are involved in other aspects of both industries.

A combined electric and natural gas utility is not something new to the industry. Many IOUs sell both electricity and natural gas to retail customers. What is new about the recent wave of mergers is that many of them are between electric utilities and natural gas production, processing, or interstate pipeline companies. These types of mergers expand greatly the business opportunities for electric utilities.

From 1997 through April 2000, 23 convergence mergers involving companies with assets valued at $0.5 billion or higher have been completed or are pending completion (Table 16).[166] No one knows for certain how long this trend will continue, but many industry observers agree that more convergence mergers will take place as deregulation of the electric power industry continues and electric and natural gas companies seek to diversify their businesses.

Strategic Benefits of Convergence Mergers

The natural gas industry has a relatively complicated structure that, depending on one's classification scheme, may consist of four major corporate segments (Table 17).

[165] J. Anderson, "Making Operational Sense of Mergers and Acquisitions," *The Electricity Journal,* Vol. 12, No. 7 (August/September 1999).

[166] A convergence merger is defined as a merger in which one company's primary business activity is electricity generation, transmission, and/or sales and the other company's primary business activity is natural gas production, processing, transportation, and/or sales.

Table 16. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through April 2000

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Allegheny Energy, Inc.	Allegheny Energy (Allegheny Power) Mountaineer Gas	Electric/Gas Gas	Allegheny: $6.7 Mountain Gas: $ 0.3 Total: $7.0	Pending	Allegheny Energy is expanding its business in West Virginia so that it can cross-sell electricity and gas in the State.
DTE Energy	DTE Energy (Detroit Edison) MCN Energy Group (Michigan Consolidated Gas Company)	Electric Gas	DTE Energy: $12.1 MCN Energy: $4.4 Total: $16.5	Pending	This merger was announced in early October 1999. DTE Energy is a holding company; it's primary subsidiary is Detroit Edison, a large investor-owned electric utility. MCN Energy Group, through its subsidiary Michigan Consolidated Gas Company, is a large gas distribution company. It also has gas pipeline, processing, and marketing activities, and it has investments in electric power. The combined company will be the largest gas and electric utility in Michigan.
KeySpan Energy Corp.	KeySpan Energy Eastern Enterprises	Electric/Gas Gas	KeySpan: $6.9 Eastern: $1.5 Total: $8.4	Pending	KeySpan is a diversified energy company providing electrical power and natural gas in New York. This merger expands KeySpan's natural gas customer base to New England.
NISOURCE (a new holding company will be formed)	NISOURCE (Northern Indiana Public Service) Columbia Energy Group	Electric/Gas Gas	NISOURCE: $5.0 Columbia: $7.0 Total: $12.0	Pending	This merger was announced in February 2000. It will create a large integrated energy company serving nine States in the Midwest.
SCANA Corporation	SCANA Corp. (South Carolina Electric & Gas) Public Service Co. of North Carolina	Electric/Gas Gas	SCANA: $5.3 PS of NC: $0.7 Total: $6.0	Pending	SCANA is the parent company of South Carolina Gas & Electric. Public Service of North Carolina, Inc. is a gas utility. This merger expands SCANA's gas distribution business and energy marketing resources.
Vectren	SigCorp Inc. (Southern Indiana Gas & Electric) Indiana Energy DPL (Natural Gas)	Electric/Gas Gas Gas	SigCorp: $1.0 Indiana Energy: $0.7 DPL: $0.4 Total: $2.1	Pending	SigCorp is a mid-size gas and electric company. Indiana Energy is a natural gas distribution and energy marketing company. Indiana Energy is purchasing DPL's natural gas distribution business. These acquisitions increase the customer base of the new combined company.
Dominion Resources	Dominion Resources (Virginia Power) Consolidated Natural Gas	Electric/Gas Gas	Dominion: $17.5 Consolidated: $6.4 Total: $23.9	Completed in 2000	Dominion Resources is predominantly a power company owning regulated and unregulated power generation assets. Consolidated Natural Gas is a large producer, transporter, distributor, and retail marketer of natural gas. This merger will create one of the Nation's largest integrated electric and natural gas companies.
Dynegy	Illinova Dynegy	Electric/Gas Gas	Illinova Corp: $6.4 Dynegy Inc: $5.3 Total: $11.7	Completed in 2000	Illinova is an energy service company; its primary subsidiary is Illinois Power, an electric and natural gas utility. Dynegy Inc. is a marketer of energy products and services. It grew from primarily a natural gas marketer to a full energy service marketing company.

Table 16. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through April 2000 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Energy East Corporation	CTG Resources, Inc. (Connecticut Natural Gas Corp.)	Gas	Energy East: \$4.9 Conn. Energy: \$0.5 CTG Resources: \$0.5 Total: \$5.9	Completed in 2000	Connecticut Natural Gas is engaged in the distribution, transportation, and sale of natural gas in Hartford and 21 other cities and towns in central Connecticut and in Greenwich, Connecticut. This represents the third acquisition by Energy East over the past few months, further strengthening its competitive position in the Northeast.
	Energy East (New York State Electric & Gas) Connecticut Energy (Southern Connecticut Gas)	Electric/Gas Gas		Completed in 2000	Energy East, the parent company of New York Electric & Gas, has chosen to focus the company on energy delivery. The merger with Connecticut Energy, the parent of Southern Connecticut Gas, a gas distribution company, increases Energy East's market share in the Northeast region.
Northeast Utilities	Northeast Utilities Yankee Energy System	Electric Gas	Northeast: \$2.2 Yankee Energy: \$0.5 Total: \$2.7	Completed in 2000	Northeast Utilities is one of New England's largest electric utility systems. Yankee Energy System, Inc. is the parent company of Yankee Gas Services Company, one of the largest natural gas distribution companies in the Northeast. Under regulatory review.
Wisconsin Energy	Wisconsin Energy Corp. Wicor (Washington Gas Co.)	Electric/Gas Gas	Wisconsin: \$5.4 Wicor: \$1.0 Total: \$6.4	Completed in 2000	Wisconsin Energy is an electricity and natural gas holding company. It owns two operating electric utilities, Wisconsin Electric and Edison Sault Electric. WICOR is a diversified holding company operating in two industries—natural gas distribution and water pump manufacturing. This merger strengthens Wisconsin Energy's gas business and helps to make it a major regional player in the evolving electricity and natural gas markets.
CMS Energy	CMS Energy (Consumer Energy) Panhandle Eastern Pipeline	Electric/Gas Gas	CMS Energy: \$11.3 Panhandle: \$2.0 Total: \$13.3	Completed in 1999	CMS is a diversified energy company having both electricity and natural gas operations. PanHandle is a natural gas pipeline company in the Midwest. Because PanHandle's pipelines connect to CMS's gas distribution and storage, this merger was a good strategic move. CMS noted that gas-fueled electricity generation continues to grow in the Midwest, and this merger improves its effort to be a major player in the gas supply market.
Duke Energy Corporation	Union Pacific Fuels	Gas	UP Fuels: \$1.4	Completed in 1999	Duke Energy Field Services, a component of Duke Energy Corporation, purchased the natural gas gathering, processing, fractionation, and liquids pipeline business of Pacific Resources (known as Union Pacific Fuels). This purchase expands Duke Energy's capability in the production of natural gas liquids and other areas in the natural gas business.
NIPSCO Industries	NIPSCO Industries (Northern Indiana Public Service) Bay State Gas	Electric Gas	NIPSCO: \$3.7 Bay State: \$0.8 Total: \$4.5	Completed in 1999	NIPSCO is a holding company for Northern Indiana Public Service, an electric and gas distribution utility. Bay State is a gas distribution utility. The merger expands NIPSCO's energy distribution market.

Table 16. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through April 2000 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
KeySpan Energy	LILCO (Long Island Lighting Co.) Brooklyn Union Gas	Electric/Gas Gas	LILCO: $4.2 Brooklyn Union: $2.3 Total: $6.5	Completed in 1998	The merger of LILCO, an electric utility, and Brooklyn Union, a gas utility, creates a regional energy distribution company serving primarily New York.
Sempra Energy	ENOVA (San Diego Gas and Electric) Pacific Enterprises (Southern California Gas)	Electric/Gas Gas	ENOVA: $5.2 Pacific: $5.0 Total: $10.2	Completed in 1998	The merger of San Diego Gas & Electric, primarily an electricity distribution company, and Southern California Gas, a gas distribution company, creates one of the largest regulated energy distribution companies in the United States.
Duke Energy Corporation	Duke Power Company PanEnergy Corporation	Electric Gas	Duke Power: $13.5 PanEnergy: $8.6 Total: $22.1	Completed in 1997	In June 1997, Duke Power Co., one of the Nation's leading electric utilities, and PanEnergy Corporation, a natural gas pipeline and marketing company, completed a merger creating Duke Energy Corporation. Duke Energy Corporation has an aggressive growth strategy, and its objective is to become a large diversified global energy company.
Enron	Enron Portland General Corp. (Portland General Electric)	Gas Electric	Enron: $23.4 Portland: $3.3 Total: $26.7	Completed in 1997	The merger between Enron, an integrated natural gas company, and Portland General Electric was the first merger between a predominantly natural gas company and an electric utility. It marked the beginning of the convergence trend in the industry and the creation of large electricity and natural gas companies.
Pacific Gas & Electric Corporation	Pacific Gas & Electric Corp. Valero Energy Corp. (Valero Natural Gas Company)	Electric/Gas Gas	PG&E Corp: $30.6 Valero: $1.5 Total: $32.1	Completed in 1997	PG&E Corporation is a large electric and natural gas company. Valero is a natural gas process and gas transportation and storage company. This acquisition increases PG&E's presence in the Texas natural gas industry.
Puget Sound Energy	Puget Sound Power & Light Co. Washington Energy Co.	Electric Gas	Puget Sound: $3.3 Washington: $1.0 Total: $4.3	Completed in 1997	This merger creates one of the largest combined electric and natural gas utilities in the Northwest. The merger expands Puget Sound Power & Light into the natural gas distribution business.
Reliant (formerly Houston Industries)	Reliant NorAm Energy	Electric Gas	Reliant: $12.3 NorAm: $4.0 Total: $16.3	Completed in 1997	Houston Industries is a holding company; Houston Light & Power, a vertically integrated electric company, is the principal subsidiary. NorAm Energy owns subsidiary companies engaging in wholesale electricity and gas marketing, interstate gas transmission, and retail natural gas distribution.
TXU (formerly Texas Utilities Co.)	Texas Utilities Co. ENSERCH (Lone Star Gas)	Electric/Gas Gas	Texas Utilities: $21.4 ENSERCH: $3.2 Total: $24.6	Completed in 1997	Texas Utilities is a combined electric and natural gas company. It owns two electric utilities in Texas. ENSERCH is a natural gas distribution and pipeline company. It owns Lone Star Gas Company, the largest natural gas distribution company in Texas. This merger significantly expands the customer base of the new combined company.

Note: Table includes mergers or acquisitions in which each company had assets valued at $0.5 billion or higher at the time of the merger.

Sources: Mergers and acquisitions were identified from trade journals, newspapers, and electric utility press releases found on Internet websites. Values of the companies' assets were obtained from the Securities and Exchange Commission 10-K filings.

Table 17. Overview of Strategic Benefits of a Combined Electric and Natural Gas Company

Natural Gas Corporate Segments	Description	Potential Strategic Benefits to Electric Company of Combining with Natural Gas Company
Producers	Perform gas exploration and production functions. Generally market gas at the wellhead to third parties who resell the gas.	Electric company may have direct access to natural gas to fuel power plants.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Pipelines	Provide wholesale transportation/transmission function. Transport gas from the field to market area. Pipeline network facilities may include gathering, transmission, compressor, storage, and metering facilities.	Access to a reliable source of natural gas for existing gas-fired power plants.
		New gas-fired merchant power plants can be strategically built relative to natural gas pipelines.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Local Distribution Companies	Provide retail sales and local transportation deliveries.	Cross-sell natural gas to retail electricity customers as a way to expand products and services.
		Help reduce unit costs by expanding overhead over larger customer base.
		Improve efficiencies of retail sales by combining billing and other administrative functions.
Marketers and Brokers	Engage in competitive wholesale gas sales and services. Buy and resell natural gas and gas management services to others on a deregulated basis.	Expand marketing effort and improve effectiveness of marketing by selling both natural gas and electricity to a common customer base.
		Apply gas company expertise and experience in gas marketing to electricity marketing.

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

Some of the major natural gas companies are vertically integrated, having exploration and production, pipelines, local distribution, and marketing components. The majority of the companies are not vertically integrated but specialize in one or two areas. Local distribution companies (LDCs) are the largest segment of the industry, with approximately 1,400 LDCs operating in the United States. The benefits to an electric utility of a convergence merger depend on where the gas company is located in the production cycle. An analysis of the current wave of convergence mergers shows that the benefits of the merger generally fall into one or more of the following areas.

Strengthen Wholesale Marketing and Trading Operations: Deregulation of the electricity and natural gas industries has created spot markets for wholesale electricity and natural gas, as well as markets for buying, selling, and trading financial instruments for risk management. In competitive commodity markets, prices for the commodities (in this case, electricity or natural gas) are sometimes volatile. Risk management, such as buying futures contracts for electricity, helps reduce the risk of price volatility. Many electric utilities and natural gas companies realize that there are similar and related techniques for electricity and natural gas marketing and trading in spot markets, and are merging to form larger organizations specializing in electricity and natural gas. This provides the opportunity to sell a diversified line of products to their customers, and it can help lower administrative and processing costs. It also facilitates arbitrage between electric power and natural gas prices.

One of the most frequently cited reasons for a convergence merger is the transferring of a gas company's experience in marketing and trading to an electric company that is relatively new in competitive markets and commodity trading. The gas industry has been deregulated since the 1980s, and over that time surviving gas companies have developed skills and experience in working in competitive energy markets.

Diversify Products and Expand Retail Markets: Most electric utilities believe that to remain competitive they need to offer more products and services to their retail customers. State-designed customer choice programs, which allow retail customers to select their energy suppliers, motivate utilities to differentiate their products from their competitors' products. One strategy to accomplish this is to merge with a local gas distribution utility and offer both electricity and natural gas services to customers. The idea of one-stop shopping appeals to some customers, and combined marketing and delivery systems can also help reduce the utility's billing, metering, and other administrative costs.

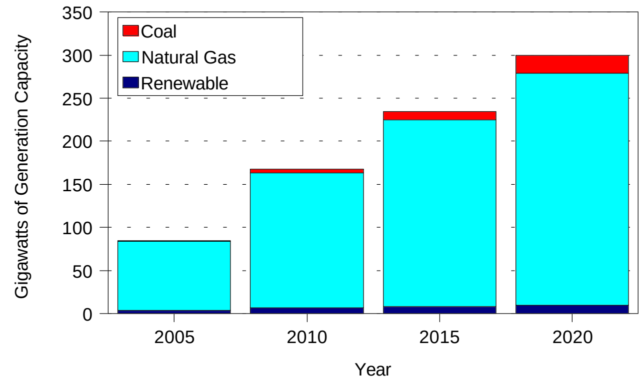
In addition to diversifying products and services, many utilities see convergence mergers as a way to increase market share, although this concept also applies to mergers involving only electric utilities. Increased market share should lower per-customer costs by spreading fixed costs over a larger customer base. Utility distribution systems have a large fixed-cost component.

Another benefit from convergence mergers is the potential for cross-selling electricity to natural gas customers and natural gas to electricity customers. The extent to which the customer base of the merging companies does not overlap represents the potential for increasing market share by cross-selling.

Expand and Strengthen Access to a Fuel Supply for Merchant Power Plants: Electric utility holding companies are merging with natural gas companies that specialize in natural gas production, processing, pipeline operation, and storage. These are called upstream and midstream functions in the natural gas industry parlance. Distribution to the ultimate customer is a downstream function. Electric utility mergers with upstream or midstream natural gas companies position the new company to benefit from the growing demand for natural gas stimulated by the projected growth in gas-fired power plants across the country.

Because of the rising demand for electricity and the retirement of older power generation units, 300 gigawatts of new generating capacity will be needed in the United States by 2020 (Figure 30). Assuming an average plant capacity of 300 megawatts, a projected 1,000 new plants will be needed to meet electricity demand and to offset plant retirements. Ninety percent of that capacity is projected to be natural-gas-fired or dual-fired gas and oil combined-cycle or combustion turbine technology. These technologies have lower capital costs and operating and maintenance costs than other technologies, and they more easily meet local and Federal Government emissions constraints, which are expected to tighten in the future. Electric utilities that own upstream and midstream natural gas resources will be positioned to compete for customers in growing natural gas markets brought on by the increase in demand for gas-fired plants. Also, by owning upstream and midstream gas resources, a company can expand its range of products and services and build a marketing strategy focused on a customer's total energy needs.

Figure 30. Cumulative Electricity Generation Capacity Additions Through 2020



Source: Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383 (2000) (Washington, DC, December 1999).

Regulatory Review of Electric Utility Mergers and Acquisitions

Electric utility mergers or acquisitions of substantial size go through a review process involving a number of Federal and State Government agencies (Table 18). At the State level, the public utility commission or its equivalent reviews the merger for potential anti-competitive effects and potential cost savings. States may also review the merger's effect on a utility's stranded costs,[167] an issue brought on by industry deregulation. Because most electric utility operations cross State boundaries, it is not uncommon for multiple States to review a merger. The extent and depth of the review can vary widely between States, depending on the merger's expected impact in the State and the resources available to conduct an evaluation.

Federal review of a proposed merger may involve up to five different agencies. Either the Federal Trade Commission (FTC) or the Antitrust Division of the Department of Justice (DOJ) could conduct a review to

[167] In general, stranded costs are historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. Stranded costs are also known as stranded investments, stranded commitments, and transition costs.

Table 18. Government Agencies Responsible for Reviewing Mergers and Acquisitions Involving Electric Utilities

Government Agency	Authority	Type of Review
Department of Justice or Federal Trade Commission	Section 7 of the Clayton Act, Hart-Scott-Rodino Antitrust Improvements Act	Examines mergers that may substantially lessen competition or tend to create a monopoly.
Federal Energy Regulatory Commission	Federal Power Act of 1935, Department of Energy Reorganization Act of 1977, Energy Policy Act of 1992	Examines mergers and other combinations to assure markets and access to reliable service at reasonable prices.
Internal Revenue Service	16th Amendment to U.S. Constitution (1913)	Determines amount of tax liability for combination.
Nuclear Regulatory Commission	Atomic Energy Act, Energy Reorganization Act of 1974, Energy Policy Act of 1992	Approves transfer of ownership of nuclear facilities.
Securities and Exchange Commission	Public Utility Holding Company Act of 1935 (PUHCA)	Assures compliance with PUHCA provisions and protection of shareholder interest.
State Public Utility Commission, State Attorney General Office	Various State Laws	Full review may include antitrust, market power, stranded costs, rates, and demand-side management. The State has the authority to allocate merger savings between ratepayers and shareholders.

Sources: Energy Information Administration, *Natural Gas 1998: Issues and Trends*, DOE/EIA-0560(98) (Washington, DC, June 1999), Chapter 7; and M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis* (Westport, CT: Praeger Publishers, 1994).

determine whether the merger is consistent with antitrust laws. Recently, the Antitrust Division of the DOJ, rather than the FTC, has reviewed electric utility mergers, but for most electric utility mergers the DOJ relies on FERC to take the lead in evaluating the competitive effects of the merger. The DOJ limits its role to participation as an interested party.[168] The Securities and Exchange Commission (SEC) can become involved in a merger or acquisition when a holding company gains control of 10 percent or more of the voting securities of another electric utility. If that is the case, the SEC reviews the merger for compliance with requirements of the Public Utilities Holding Company Act of 1935. The Nuclear Regulatory Commission (NRC) reviews a proposed merger or acquisition when it involves the transfer of a nuclear power plant operating license.

Of all Federal Government agencies involved in reviewing a proposed merger between electric utilities, FERC's review is probably the most extensive, covering the merger's potential effects on competition in the industry, electricity rates to customers, and regulation. FERC sometimes will request merger applicants to prepare special reports showing the merger's effect on market power or the cost savings and efficiencies that are expected from the merger. These reports and other documents, such as public comments about the merger, are available on the Commission's website (www.ferc.fed.us). Depending on the level of public interest, the size of the merging companies, and the merger's potential impact on the industry, FERC may hold public hearings to obtain information and to discuss important issues associated with the merger.

Divestiture of Power Generation Assets

The previous sections discussed mergers and acquisitions and their effects on the structure of the industry. Recent divestitures of power generation assets (i.e., power plants) by a number of IOUs is another type of corporate realignment that is changing the structure of the industry. Divestiture of generation assets is defined as the sale of assets to another company, or the transfer

[168] M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis* (Westport, CT: Praeger Publishers, 1994).

of assets from the regulated utility subsidiary to an unregulated subsidiary within the company structure.

Over the past 3 years, IOUs have divested power generation assets at unprecedented levels. From late 1997 through April 2000, 51 IOUs (32 percent of the 161 IOUs owning generation capacity) have divested or are in the process of divesting 156.5 gigawatts of power generation capacity, representing approximately 22 percent of total U.S. electric utility generation capacity (Table 19). Of the 156.5 gigawatts, 86.2 gigawatts have been sold or are pending completion of the sale, 31.9 gigawatts are up for sale, and 38.3 gigawatts will be transferred by an IOU to its nonutility subsidiary. Some industry observers have estimated that ownership may change for up to 50 percent of total U.S. generation capacity (about 364 gigawatts as of 1998) over the next 10 years. No one can predict with certainty the volume of future divestitures, but more are expected as restructuring of the electric power industry proceeds.

The idea of an electric utility divesting generation assets can be traced back to before November 1996, when FERC issued Order 888 requiring electric utilities to allow access to their transmission lines to other electricity suppliers. As discussed in Chapter 7, FERC believed that access to transmission lines was necessary in order for a competitive power generation market to develop. Some industry participants believed, however, that open access to the transmission system would not be sufficient. When transmission line capacity becomes limited due to high usage, it is argued that utilities that own the transmission lines will favor power from their own generators over a competitor's generator. Many thought the answer to this problem was for FERC to require utilities that own both power generators and transmission lines to divest their power generation assets.

In Order 888, FERC took a less intrusive alternative to actual divestiture of generation assets by requiring functional unbundling. Functional unbundling is achieved when a company's organizational structure separates operation of and access to the transmission system from power generation. To comply with functional unbundling, electric utilities created an open access transmission tariff, established separate rates for wholesale generation, transmission, and ancillary services, and established an electronic information network that supplies information on the availability of transmission capacity to customers. All IOUs have complied with FERC's functional unbundling requirements and in some regions electric utilities have formed independent system operator (ISO) companies and turned control (but not ownership) of their transmission assets over to the ISOs. This action can be construed as a way of unbundling power generation from transmission.

Why Investor-Owned Electric Utilities Are Divesting Power Generation Assets

Even though all IOUs have functionally unbundled generation from transmission, and some have formed ISOs, many utilities have divested their power plants because of State requirements or as a result of strategic business decisions made by the utility. With regard to State requirements, States that are opening the electric market to retail competition view the separation of power generation ownership from power transmission and distribution ownership as a prerequisite for retail

Table 19. Status of Power Generation Asset Divestitures by Investor-Owned Electric Utilities, as of April 2000

Status Category	Capacity (GW)	Percent of Total	Percent of Total U.S. Generation Capacity
Sold	58.0	37	8
Pending Sale (Buyer Announced)	28.2	18	4
For Sale (No Buyer Announced)	31.9	20	4
Transferred to Unregulated Subsidiary[a]	4.1	3	1
Pending Transfer to Unregulated Subsidiary	34.2	22	5
Total	**156.5**	**100**	**22**

[a]Includes generation capacity owned by a holding company that is being transferred from its electric utility subsidiary to its nonutility subsidiary.

Note: Totals may not equal sum of individual components because of independent rounding.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through September 1999.

competition. Some States have passed laws requiring utilities to divest their power plants. California, Connecticut, Maine, New Hampshire, and Rhode Island are examples of States with laws explicitly requiring utilities to divest their fossil and hydroelectric generation assets and, potentially, any ownership in nuclear power generating assets.

In other States that have passed electricity industry restructuring legislation, the requirements for unbundling are not always clear and vary from State to State. In some instances, the State public utility commission (PUC) may encourage divestiture to arrive at a quantifiable level of stranded costs for purposes of recovery during the transition to competition. On the other hand, many times the PUCs are not explicit in their unbundling requirements, leaving it to the utility to propose a method that satisfies the PUC's unbundling objectives and satisfies the strategic and economic objectives of the utility. The utility prepares a company restructuring plan which may include selling its assets or, alternatively, transferring its assets to an unregulated subsidiary company. Negotiation and compromise between the PUC and the utility are part of the process of finalizing the plan. Not all States that have restructured their electricity industry require resident electric utilities to unbundle their assets.

As a business strategy, a few utilities have decided to sell their power plants, indicating that they cannot compete in a competitive power market. For example, General Public Utilities, serving customers in New Jersey and Pennsylvania, sold its fossil-fueled and hydroelectric generating assets, and will focus on running its transmission and distribution systems in a regulated environment. Potomac Electric Power Company, serving primarily Maryland and Washington, DC, announced in February 1999 that it will sell its generation business and concentrate on distribution. Both of these companies concluded that at their present level of power generation capacity, they are too small to compete effectively in a competitive power market. It is expected that more small electric utilities will either merge with other utilities or sell their power generation assets.

In a few instances, an IOU will divest power generation capacity to mitigate potential market power resulting from a merger. For example, American Electric Power Company and Central and South West Corporation have agreed, as a condition for obtaining approval of their pending merger, to divest 1,604 megawatts of generation capacity in Texas.

Five Census Divisions Accounting for Most Generation Asset Divestitures

Five census divisions—Middle Atlantic, New England, South Atlantic, East North Central, and Pacific Contiguous—account for a total of 141.3 gigawatts of the divested capacity, representing 90 percent of the 156.5 gigawatts of actual and planned divestitures in the United States as of early April 2000 (Figure 31). The majority of divestitures are concentrated in these regions because the States in these regions were among the first in the Nation to promote retail competition. With the exception of States in the South Atlantic Division, most of the States in the other four divisions passed legislation in 1996 or 1997 restructuring the electricity industry, and they have had over 2 years to implement their restructuring programs.

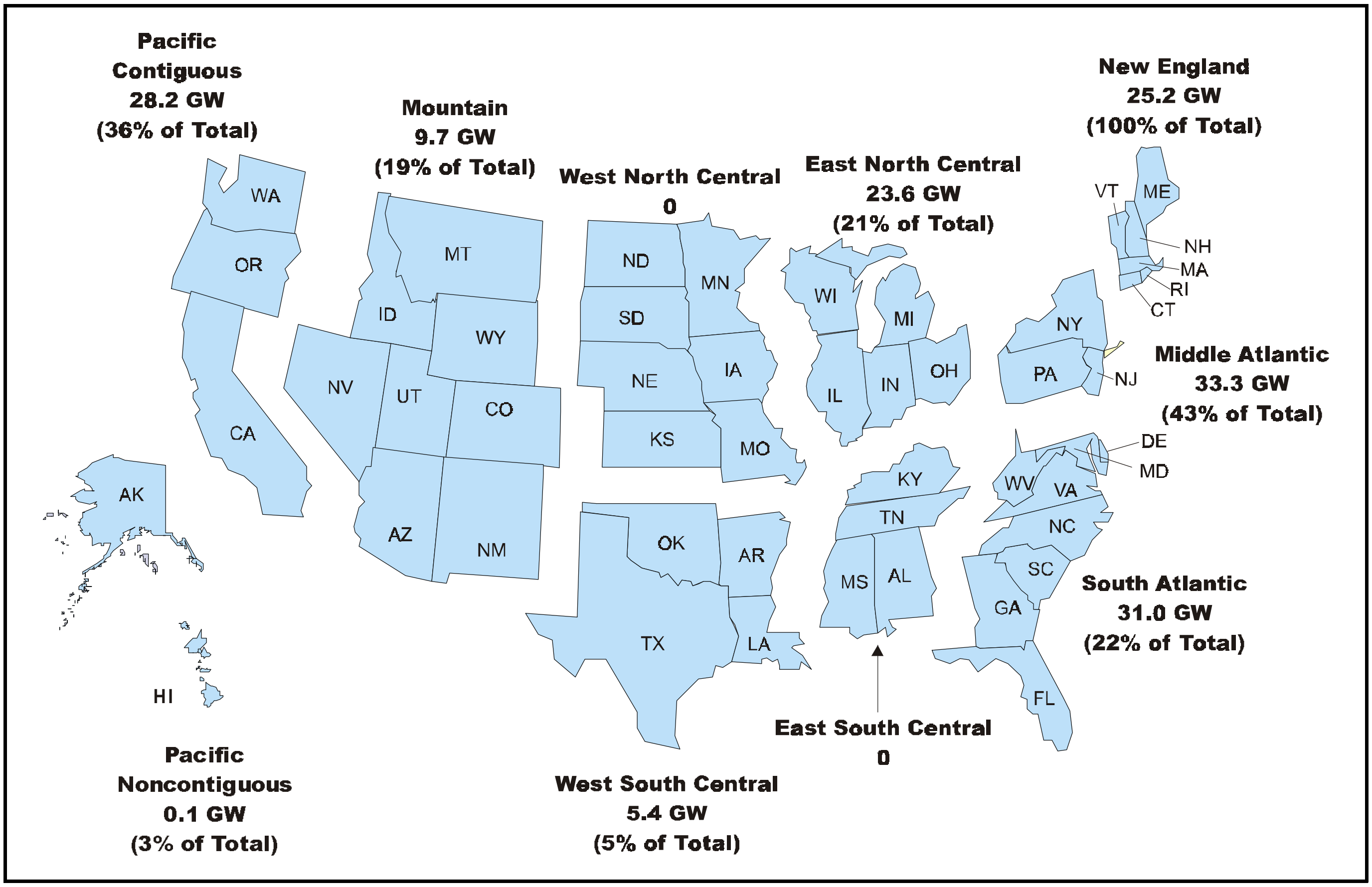
IOUs in New England have completed divesting their power plants; approximately 25.2 gigawatts have been sold, representing all of the region's generating capacity. Capacity in the region that has not been divested is owned by IPPs or municipal or Federal Government power plants. IOUs in the Middle Atlantic region, mainly in New York and Pennsylvania, have divested or are in the process of divesting more than 33 gigawatts, accounting for approximately 43 percent of the region's generating capacity. IOUs in California have divested slightly over 28 gigawatts, representing about 36 percent of the generating capacity in the Pacific Contiguous region.

Selling Generation Assets and the Approval Process

How power plants are sold is important to the owner and potential buyers. The procedure should ensure fairness to all interested buyers and ensure that the utility gets a fair market value. The most popular divestiture method is the auction. The advantages of auctions are that they have been used successfully for many years to sell products, they can be easily understood and monitored, and they can produce greater revenues than other methods, if designed properly.

Many of the IOUs divesting assets have used a two-stage auction process. In the first stage, the utility advertises the sale of the plant and bidders submit notifications of interest back to the utility. Advertising the sale of the plant can be accomplished in many ways. One way is to develop a potential buyers list and send each a notification that a power plant is for sale. In the

Figure 31. Investor-Owned Electric Utility Generation Capacity Divested or to be Divested by Census Division, as of April 2000



Note: Nationally, approximately 22 percent of total power generation capacity has been divested or will be divested.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through April 2000.

second stage, the utility selects a shortlist of buyers. Short-listed bidders conduct due diligence and submit their final bids. Sometimes post-bid negotiations are conducted, but they have the tendency to reduce the bid price because the bidder, knowing that negotiations will be conducted, can change the original bid price.

When the divestiture involves many plants, packaging of the plants is important. Packaging refers to the group of assets that will be sold at one auction. In many cases, bidders cannot submit a bid for just some of the assets, but must bid on all the assets in the package. Thus, it is important to combine assets in a way that will interest potential buyers.

All power plant sales must be approved by the PUC of the affected States. The PUC examines the sale's impact on the utility's customers, the environment, and other public interests, and resolves any conflicts which arise. Ideally, contentious issues are resolved during the planning stage.

With the exception of hydroelectric power plants, the Federal Government has only a small role in IOU asset divestitures. FERC's position is that generation assets are not under its jurisdiction and its approval is not required unless the sale includes transmission assets along with generation assets.

Conclusions About Mergers, Acquisitions, and Divestitures of Generation Assets

Deregulation of the electric power industry and the ensuing competition is driving IOUs to formulate strategies that will help them to compete in the changing industry. Many times the strategy is a merger or acquisition. Recent mergers have created large vertically integrated regional electric utilities, and more are expected as some of the pending mergers are completed. One effect of these mergers is that ownership of IOU power generation capacity is becoming more concentrated. By the end of 2000, it is expected that the 20 largest IOUs will own about 72 percent of total IOU capacity (Figure 29).

Over the past few years, IOUs have increasingly merged with natural gas production and gas pipeline companies, creating vertically integrated energy companies. These mergers are motivated primarily by the growth in gas-fired power plants and the opportunity to become a major fuel supplier to these power plants. Combined electricity and natural gas marketing and diversification of products and services are also reasons for these mergers.

Induced by State government restructuring of the electric industry and the emergence of retail competition, many IOUs have divested their power generation assets and will focus on operating their transmission and distribution business. From 1998 through April 2000, IOUs have either divested or are in the process of divesting approximately 156.5 gigawatts of power generation capacity. Over 95 percent of this capacity has been or will be acquired by IPPs, furthering the growth of the IPP segment of the industry.

Since the early 1990s, when deregulation and restructuring of the industry began, mergers and acquisitions in the industry have accelerated. The intent of these corporate realignments is to strengthen the company's position in the competitive industry. It is not clear, however, if these strategies will benefit most companies, and if the industry and electric customers will be better off as well.

Appendix A

History of the U.S. Electric Power Industry, 1882-1991

Appendix A

History of the U.S. Electric Power Industry, 1882-1991[169]

Beginnings: 1882-1900

The modern electric utility industry began in the 1880s. It evolved from gas and electric carbon-arc commercial and street lighting systems. Thomas Edison's Pearl Street electricity generating station, which opened September 4, 1882, in New York City, introduced the industry by featuring the four key elements of a modern electric utility system. It featured reliable central generation, efficient distribution, a successful end use (in 1882, the light bulb), and a competitive price. A model of efficiency for its time, Pearl Street used one-third the fuel of its predecessors, burning about 10 pounds of coal per kilowatthour, a "heat rate" equivalent of about 138,000 Btu per kilowatthour.[170] Initially the Pearl Street utility served 59 customers for about 24 cents per kilowatthour.[171] In the late 1880s, power demand for electric motors brought the industry from mainly nighttime lighting to 24-hour service and dramatically raised electricity demand for transportation and industry needs. By the end of the 1880s, small central stations dotted many U.S. cities; each was limited to a few blocks area because of transmission inefficiencies of direct current (dc).

The hydroelectric development of Niagara Falls by George Westinghouse in 1896 inaugurated the practice of placing generating stations far from consumption centers. The Niagara plant transmitted massive amounts of power to Buffalo, New York, over 20 miles away. With Niagara, Westinghouse convincingly demonstrated both the general superiority of transmitting power with electricity rather than by mechanical means (the use of ropes, hydraulic pipes, or compressed air had also been proposed) and the transmission superiority at that time of alternating current (ac) over direct current (dc). Niagara set a contemporary standard for generator size, and was the first large system supplying electricity from one circuit for multiple end-uses (railway, lighting, power).

Electric utilities spread rapidly in the 1890s. Municipally owned utilities predominantly supplied street lighting and trolley services and reached their peak share of total generation, about 8 percent, at the turn of the century.[172] Privately owned multiservice utilities controlled the rest of the industry, aggressively competing for central city markets. Competition and technological improvements served to lower electricity prices steadily, with nominal residential prices falling to less than 17 cents per kilowatthour by the beginning of the 20th century.

Era of Private Utilities: 1901-1932

From 1901 through 1932, growing economies of scale hastened growth and consolidation in the electric utility industry, as well as the beginnings of State and Federal regulation. Larger, more efficient steam turbine-powered generators quickly replaced reciprocating steam engines; average heat rates dropped from 92,500 Btu per kilowatthour in 1902 to 20,700 Btu per kilowatthour by 1932.[173] As a direct consequence of those growing efficiencies, small private and municipal lighting and railway or power companies either merged with, purchased electricity from, or were absorbed quickly by ever-larger, more efficient private multiservice systems. Systems and cities interconnected with high voltage transmission lines. Private electric utility ownership also

[169]The following is a historical sketch of the electric power industry from 1882 through 1991. The information for utilities from 1882 to 1984 is excerpted from Energy Information Administration (EIA), *Annual Outlook for U.S. Electric Power 1985*, DOE / EIA-0474(85) (Washington, DC, August 1985). Utility and nonutility information from 1985 to 1991 is excerpted from EIA, *The Changing Structure of the U.S. Electric Power Industry 1970-1991,* DOE / EIA-0562 (Washington, DC, March 1993).

[170]C. E. Neil, "Entering the Seventh Decade of Electric Power, Some Highlights in the History of Electrical Development," reprinted from *Edison Electric Institute Bulletin* (September 1942), p. 6.

[171]A.J. Foster, *The Coming of the Electrical Age to the United States* (New York, NY: Arno Press, 1979), pp. 120, 123, 181.

[172]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

[173]C.E. Neil, "Entering the Seventh Decade of Electric Power," from *Edison Electric Institute Bulletin* (September 1942), p. 6.

consolidated into large utility holding companies, each "holding" controlling interest in a number of electric utilities. At their peak in the late 1920s, the 16 largest electric power holding companies controlled more than 75 percent of all U.S. generation.[174]

The growth of utility service areas, first beyond city boundaries and then across State lines, brought State regulation of electric utilities in the early 1900s to ensure that the monopolistic utilities did not take advantage of their customers. Georgia, New York, and Wisconsin established State public service commissions in 1907, followed quickly by more than 20 other States. Basic State powers included the authority to franchise the utilities, to regulate their rates, financing, and service, and to establish utility accounting systems.

The foundations for strong Federal involvement in the electricity industry were established between 1901 and 1932, based on three factors: first, the electric power industry became recognized as a natural monopoly in interstate commerce (producing a product most efficiently provided by one supplier) subject to Federal regulation; second, the Federal Government owned most of the Nation's hydroelectric resources; and third, Federal economic development programs accelerated, including electricity generation. In 1906, Congress authorized the sale of surplus Federal power from western irrigation projects, giving sale preference to municipalities. The Federal Water Power Act of 1920 (P.L. 66-280) codified Federal powers and established the Federal Power Commission (FPC) to issue hydroelectric development licenses revokable after 50 years. In 1928, Congress authorized the Boulder Canyon Project for irrigation, flood control, and electricity production.

From 1901 to 1932, electric utility capacity and generation grew at annual average rates of about 12 percent a year, despite a 14-percent absolute drop in generation from 1929 to the Depression-era low in 1932. Both the number of municipal utilities and their share of total generation dropped steadily, as municipals were overwhelmed by larger, more efficient private systems. By 1932 municipals contributed only 5 percent of total generation. At the same time, State-owned utilities and Federal systems, however, grew noticeably, together contributing more than 1 percent of total generation. Private utilities provided the remaining 94 percent.[175] Electricity prices dropped, with nominal residential electricity prices falling to 5.6 cents per kilowatthour in 1932, a level about one-third their price at the beginning of the century. In 1907, only 8 percent of all dwellings were using electricity; by 1932, this figure had risen to 67 percent. By 1932 considerably more than 80 percent of urban dwellings were electrified, while only 11 percent of farm dwellings had electrical service. This disparity between urban and rural service led to demands by farm interests for government help in obtaining electric power.[176]

Emergence of Federal Power: 1933-1950

The Federal Government became a regulator of private utilities in the 1930s; it also became a major producer of electricity beginning in this period. The 1933-1950 period was also characterized by continued growth of the industry, increased consolidation and interconnection, and increasing economies of scale.

1933-1941

The Federal Government moved quickly in the mid-1930s to regulate private power and, where opportunities appeared, to produce and distribute less expensive Federally produced electricity to preference customers. Federal participation was hastened by widespread public perception of private utility abuses and national efforts to overcome the Depression.

First, the Federal Government moved to regulate private utilities. To counter utility abuses beyond State control, the Public Utility Holding Company Act of 1935 (PUHCA, P.L. 74-333) provided for the regulation of utility holding companies by the Securities and Exchange Commission (SEC). The Federal Power Act of 1935 (Title II of PUHCA) established FPC regulation of utilities involved in interstate wholesale transmission and sale of electric power.

Second, the Federal Government encouraged the growth of rural electricity service by subsidizing the formation of rural electric cooperatives. The Rural Electrification Act of 1936 (P.L. 74-605) established the Rural Electrification Administration (REA) to provide loans and assistance to organizations providing electricity to rural

[174]*Encyclopedia Americana*, International Edition, Vol. 22 (New York, NY: Americana Corporation, 1977), p. 769.

[175]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

[176]U.S. Bureau of the Census, *Historical Statistics of the United States, Colonial Times to 1970, Bicentennial Edition*, Part 2 (Washington, DC, 1975), p. 827.

areas and towns with populations under 2,500. REA-backed cooperatives enjoyed Federal power preferences plus lower property assessments, exemptions from Federal and State income taxes, and exemption from State and FPC regulation. As a result, by 1941 the proportion of farm homes electrified rose to 35 percent, more than three times that of 1932.[177]

Third, in the 1930s Federal electricity generation expanded, providing less expensive electricity to municipals and cooperatives. Large Bureau of Reclamation dams began serving the western States; Hoover Dam began generation in 1936, followed by other large projects. Grand Coulee, the Nation's largest hydroelectric dam, began operation in 1941. U.S. Army Corps of Engineers flood control dams provided additional low-priced power for preference customers. Under the Tennessee Valley Authority Act of 1933 (P.L. 73-17), the Federal Government supplied electric power to States, counties, municipalities, and nonprofit cooperatives, soon including those of the REA. The Bonneville Project Act of 1937 (P.L. 75-329) pioneered the Federal power marketing administrations. By 1940, Federal power pricing policy was set; all Federal power was marketed at the lowest possible price while still covering costs. From 1933 to 1941, half of all new capacity was provided by Federal and other public power installations. By the end of 1941, public power contributed 12 percent of total utility generation, with Federal power alone contributing almost 7 percent.[178]

During the pre-World War II years, electricity generating systems continued to grow in size and efficiency. Maximum turbine sizes and pressures doubled, and steam temperatures increased; generator cooling by pressurized hydrogen was introduced, resulting in higher generator outputs. Average heat rates dropped to 18,600 Btu per kilowatthour by 1941.[179] Improvements in transformers, circuit breakers, protection and reclosing devices, and transmission and distribution systems also continued, increasing both the efficiency and the reliability of electric utility systems.

Electricity prices continued to decline. Nominal residential electricity prices fell to 3.73 cents per kilowatthour in 1941, a drop of about one-third from 1932. Demand for electric power grew steadily from 1932 to 1941, with generation growth averaging over 8 percent a year, although capacity increased less than 2.5 percent per year.

1942-1950

Soaring electricity demand during World War II was met by increased use of privately owned capacity and a dramatic growth in Federal power. From 1941 to 1945, Federal capacity growth averaged 21 percent a year, and generation grew by 27 percent. By the war's end, Federal electricity generation had grown to more than 12.5 percent of U.S. generation.[180] Total U.S. generation grew at an annual average rate of over 7.5 percent during these war years, with capacity increasing at an annual average rate of almost 4.5 percent.

Both residential and commercial end use of electricity grew rapidly from 1941 to 1945, despite the war. Almost one-half of all farm dwellings were electrified by 1945. Growth in demand was helped by continuing technological improvements, yielding overall heat rates below 16,000 Btu per kilowatthour[181] and residential electricity price drops averaging over 2 percent a year.

Public and Federal power continued to grow, and terms of public sale improved. Generating capacity built for defense was directed to public sale. The 1944 Pace Act (Department of Agriculture Organic Act, P.L. 78-425) extended REA indefinitely, dropped REA long-term interest rates below market rates, and authorized additional dam construction. The Flood Control Act of 1944 (P.L. 78-534) gave the Secretary of Interior jurisdiction over U.S. Army Corps of Engineers' electric power sales and extended public preference to all Corps power. The Southwestern Power Administration (SWPA) and the Southeastern Power Administration (SEPA) were established in 1943 and 1950, respectively, to market Federal power to preference customers. The First Deficiency Appropriation Act of 1949 (P.L. 81-71) in effect authorized TVA construction of thermal-electric power plants for commercial electricity sale. By 1950, Federal generation contributed over 12 percent of total U.S. generation, while cooperatives and other public power provided almost 7 percent.[182] In settling the Hope Natural Gas case (Federal Power Commission vs. Hope Natural Gas Company, 1944), the Supreme Court closed

[177]*Ibid.*
[178]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), pp. 2, 24.
[179]C.E. Neil, “Entering the Seventh Decade of Electric Power,” from *Edison Electric Institute Bulletin* (September 1942), p. 6.
[180]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.
[181]Edison Electric Institute, *EEI Pocketbook of Electric Utility Industry Statistics* (New York, NY: 1983), p. 21.
[182]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

a longstanding dispute by allowing either original or replacement cost accounting in utility rate-making, so long as just and reasonable rates result.

Following a brief decline at war's end in 1945, overall demand for electricity continued to grow. From 1945 through 1950, generation growth averaged more than 8 percent a year and capacity over 6.5 percent. Residential electricity consumption grew most rapidly, almost 14 percent a year, and the share of farms electrified rose to almost 80 percent.[183] Growth was encouraged by continued efficiency improvements; by 1950 heat rates had fallen below 15,000 Btu per kilowatthour.[184] Drops in nominal residential electricity prices averaged 3 percent a year.

Utility Prosperity: 1951-1970

The era following the end of World War II through 1970 marked a time of essentially uninterrupted prosperity for the electric utility industry. Demand for electricity grew rapidly, consistently, and predictably, while electricity prices continued to fall. The arrival of commercial nuclear power held the promise of an even more prosperous future. At the same time, problems that were later to affect the industry dramatically either did not exist or were not yet serious.

The 1950s

Three major characteristics marked the electric utility industry in the 1950s: robust growth, the introduction of commercial nuclear power, and other public power expansion replacing Federal power growth.

From 1950 to 1960, generation grew by an average of over 8.5 percent a year, led by strong increases in residential electricity demand and near completion of rural electrification. Capacity grew slightly more rapidly than generation, averaging almost 9.5 percent annually. With generating efficiencies still improving, electricity prices continued to decline, as evidenced by drops in nominal residential electricity prices averaging about 1 percent a year.[185]

Commercial nuclear power was introduced in the 1950s. The Atomic Energy Act of 1954 (P.L. 83-703) allowed private development of commercial nuclear power, and the Price-Anderson Act (P.L. 85-256) reduced private liability by guaranteeing public compensation in the event of a commercial nuclear catastrophe. The Nation's first central station commercial nuclear reactor, located in Shippingport, Pennsylvania, began operation in 1957.

Finally, during the 1950s new Federal power plant construction slowed, but the slowdown was offset by more rapid growth of other public power capacity. Both the “no new starts” policy of the Eisenhower Administration and a lack of additional major hydroelectric sites checked major new Federal development. Nevertheless, projects begun earlier continued to come on line, and Federal generation reached its highest share of total generation, more than 17 percent, in 1957. TVA added thermal capacity, by 1960 becoming predominantly a thermal rather than hydroelectric system. Non-Federal public power grew rapidly in the 1950s, led by cooperatives, power districts, and State projects. Generation from non-Federal public power plants and cooperatives increased from more than 6.5 percent of total generation in 1950 to almost 8.5 percent in 1960.[186]

The 1960s

During the 1960s high electricity growth rates continued, paralleled by growth in nuclear power generation. During the period, however, signs of future difficulties in the electric power industry appeared, including decreasing efficiency gains, escalating costs, and environmental concerns.

Vigorous growth continued throughout the 1960s, prompted by overall economic growth, declining real energy prices, and growing consumer preference for electricity because of its convenience, versatility, and price. Generation and capacity growth averaged almost 7.5 percent a year, predominantly from increases in petroleum- and gas-fired generation. Cooperatives accelerated capacity additions, and by 1970 non-Federal public power contributed well over 10 percent of total utility generation.[187] Demand grew nearly 7.5 percent a year, helped by annual declines of over 1.5 percent in residential and commercial electricity prices.[188]

[183]U.S. Bureau of the Census, *Historical Statistics of the United States* (Washington, DC, 1972), pp. 827-828.
[184]Derived from Edison Electric Institute, *EEI Pocketbook of Electric Utility Industry Statistics* (New York, NY: 1983), p. 21.
[185]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 23.
[186]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.
[187]Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.
[188]Energy Information Administration, *Annual Energy Review 1984*, DOE/EIA-0384(84) (Washington, DC, April 1985), p. 187.

New technology introduced during this period included automated controls and computers. Technological advances during the 1960s were led by the growth of commercial nuclear power. Facing continued high demand growth and encouraged by performance of small nuclear facilities, utilities began ordering many more nuclear units of far greater size and still undemonstrated efficiency. In contrast to the 837 megawatts of new capacity ordered in the 1950s, with units averaging fewer than 150 megawatts, in the 1960s, 86,596 megawatts were ordered, averaging about 850 megawatts per unit.[189] Generation by nuclear power rose to over 1 percent of the U.S total by 1970.[190]

During the 1960s some signs of difficulties in the electric utility industry began to appear. First, environmental requirements became a noticeable component of electric utility costs. Coal-fired power plants began to experiment with emission control equipment to decrease the amount of sulfur dioxide (SO_2) emitted into the atmosphere. Tall emission stacks were introduced to disperse SO_2. Further, the National Environmental Policy Act of 1969 (NEPA, P.L. 91-190) required utilities seeking Federal permits for new power plants to prepare and defend environmental impact statements (EISs) as a part of the permit process. Second, the increasing efficiencies historically characterizing the industry flattened in the mid-1960s. From 1960 to 1970, the average size of thermal plants more than doubled. Heat rates, on the other hand, declined only a little, from about 10,800 Btu per kilowatthour to 10,500 Btu per kilowatthour.[191] Finally a major Northeastern power blackout in 1965 raised concerns about the reliability of the huge interconnected, interdependent power networks. Response to the blackout included formation of the North American Electric Reliability Council (NERC) and its regional reliability councils to promote the reliability and adequacy of bulk power supply.

Years of Challenge: 1971-1984

The 1970s

During the 1970s, the electric utility industry moved from decreasing unit costs and rapid growth to increasing unit costs and slower growth. Among the major factors affecting the electric utility industry during the period were general inflation, increases in fossil-fuel prices, environmental concerns, conservation, and problems in the nuclear power industry.

First, electric utilities with ambitious capital expansion programs heavily financed by borrowing were particularly affected by inflation. As technical and regulatory requirements increased construction lead times, the impact of inflation was compounded.

Second, in the 1970s all fossil-fuel prices rose sharply. Petroleum costs more than doubled in 1974 alone and increased an average of over 26 percent a year for the 1970-1980 period. Natural gas prices, accelerated by decontrol under the Natural Gas Policy Act (NGPA, P.L. 95-621), rose by over 23 percent a year, with the largest increases occurring after 1978. Coal price increases averaged almost 16 percent a year.[192]

Third, during the 1970s environmental legislation increased the costs of building and operating electric utility (particularly coal-fired) power plants. The Clean Air Act of 1970 (CAA, P.L. 91-604) and its amendments in 1977 (P.L. 95-95) required utilities to reduce pollutant emissions, particularly SO_2, causing increases in capital, fuel, and operating costs. The Act also limited use of tall stacks to disperse emissions. The Federal Water Pollution Control Act of 1972 ("Clean Water Act," P.L. 92-500) limited utility waste discharges into water. In addition, the Resource Conservation and Recovery Act of 1976 (RCRA, P.L. 94-580) directed standards for disposal of both hazardous and nonhazardous utility wastes.

Finally, conservation legislation effectively barred utilities from wider use of natural gas and petroleum. The Energy Supply and Environmental Coordination Act of 1974 (ESECA, P.L. 93-319) allowed the Federal Government to prohibit electric utilities from burning natural gas or petroleum. The 1978 Powerplant and Industrial Fuel Use Act (FUA, P.L. 95-620) succeeded ESECA and extended Federal prohibition powers. The National Energy Conservation Policy Act of 1978 (NECPA, P.L. 95-619) required utilities to provide residential consumers free conservation services to encourage slower growth of electricity demand.

[189]Energy Information Administration, *U.S Commercial Nuclear Power Historical Perspective, Current Status, and Outlook*, DOE / EIA-0315 (Washington, DC, March 1982), p. 10.

[190]Energy Information Administration, *Annual Energy Review 1984*, DOE / EIA-0384(84) (Washington, DC, July 1985), p. 171.

[191]Energy Information Administration, *Thermal-Electric Plant Construction Cost and Annual Production Expenses—1979*, DOE / EIA-0323(79) (Washington, DC, May 1982), p. 10.

[192]Energy Information Administration, *Fuel Choice in Steam Electric Generation: A Retrospective Analysis*, EIA-MO12 (Washington, DC, October 1985), Table 2.

Expected high electricity demand growth did not materialize in the 1970s. Instead, capacity growth began to outrun increases in demand. For the first time in the history of U.S. electric power, electricity prices rose consistently, with nominal price increases averaging 11 percent a year. Consequently, demand and generation growth moderated to just over 4 percent a year. However, capacity growth continued at a rate of 6 percent a year. Slackened demand growth, coupled with completion of expensive new capacity, left utilities with excess capacity and without new revenues to pay for it. As a result, some electric utilities suffered financial setbacks and incurred declining investor confidence.

The commercial nuclear power industry expanded rapidly but also met serious reverses. From 1971 through 1974, 131 new nuclear units were ordered, at an average capacity of about 1,100 megawatts.[193] As a result, inflation, labor, and materials cost increases quickly affected construction costs of nuclear power plants, while high interest rates raised financing costs. Capital costs rose from about $150 per kilowatt in 1971 to more than $600 after 1976.[194] Utilities building commercial nuclear facilities faced financial difficulties in justifying and meeting these increased costs. Safety concerns increased. First, in February 1979 the Nuclear Regulatory Commission (NRC) shut down five operating reactors following concerns about durability during earthquakes. Then, on March 28, 1979, the Nation's most significant commercial nuclear accident occurred at the Three Mile Island Number 2 reactor near Harrisburg, Pennsylvania.

These events heightened public concerns and spurred opposition to commercial nuclear power. As a result of higher costs, slackening electricity demand growth, and public concern, demand for nuclear power plants dropped quickly in the mid- and late-1970s. After 1974, new orders plummeted and cancellations accelerated. No new reactor orders were placed after 1978. Moreover, 63 units were canceled between 1975 and 1980.[195]

The Early 1980s

The early 1980s were marked by almost no growth in the U.S. electric utility industry. In 1982 total net generation dropped more than 2 percent, the first absolute decline since 1945. In the mid-1980s, however, the industry returned to moderate if unspectacular growth.

Cost and price increases continued to slow the growth of electric power in the early 1980s. Costs of new nuclear power plants increased to more than $1,200 per kilowatt of capacity in the early 1980s.[196] High inflation ensured increases in other financial and operating costs. As a result, electricity prices rose sharply. Average end-use electricity prices (nominal) increased by almost 19 percent in 1980, 15 percent in 1981, and 12 percent in 1982. End-use electricity consumption responded to rising prices and a sluggish economy by increasing only 1 percent in 1980 and 2.5 percent in 1981. Demand then dropped almost 3 percent in 1982, because of a decline in industrial electricity use of nearly 10 percent, as part of that year's severe economic downturn.[197]

Electricity generation increased in 1983 to a record high of 2,310 billion kilowatthours. Capacity, however, grew by little more than 1 percent over 1982, the smallest increase since 1956. Industrial electricity use grew most rapidly among end-use sectors, rebounding from its 1982 decline. The average price of electricity increased by 2.6 percent, less than the rate of inflation. In 1984, electricity posted its largest single-year increase in generation since 1976, 4.5 percent. Though not large by historic standards, the growth rate reflected a healthy economy, generally increasing preference for electricity, and a decline in electricity's price relative to other forms of energy. Capacity grew by 2.1 percent in 1984, led by coal-fired and nuclear-powered additions. Electricity prices increased at the rate of inflation, leaving real prices unchanged.

[193]Energy Information Administration, *U.S. Commercial Nuclear Power Historical Perspective, Current Status, and Outlook*, DOE/EIA-0315 (Washington, DC, March 1982), p. 10.

[194]Energy Information Administration, *Survey of Nuclear Power Plant Construction Costs 1983*, DOE/EIA-0439(83) (Washington, DC, December 1983), p. 8.

[195]Energy Information Administration, *U.S Commercial Nuclear Power Historical Perspective, Current Status, and Outlook*, DOE/EIA-0315 (Washington, DC, March 1982), p. 10.

[196]Energy Information Administration, *Survey of Nuclear Power Plant Construction Costs 1984*, DOE/EIA-0439(84) (Washington, DC, November 1984), p. 15.

[197]Energy Information Administration, *Annual Energy Review 1984*, DOE/EIA-0384(84) (Washington, DC, July 1985), pp. 179, 187.

From 1980 through 1984, net electricity generation grew an average of a mere 1.4 percent annually. End-use sales grew by only 2.1 percent a year, the slowest rate of growth since the early years of the Great Depression. Capacity, however, increased 2.3 percent a year, further raising reserves available to meet unexpected demand. Nuclear capacity additions entering commercial service, despite the absence of new orders, led the rate of new capacity growth, increasing by 6.1 percent a year. Prices rose by approximately 8 percent a year. Commercial electricity use increased more than any other end use, averaging almost 4.5 percent a year; industrial end use grew less than 1 percent a year.[198]

Nonutility Growth: The Late 1980s[199]

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 share of electric power generation increased steadily between then and 1979, when it reached 97 percent. The trend reversed itself in the 1980s, and by 1991 the electric utility share declined to 91 percent.

Increasingly, nonutilities were 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.[200]

About one-half of 1991 nonutility capacity was 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 kilowatthours of electricity in 1991, were engaged in 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 were 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 contrast, utilities produced the majority of their electricity by burning coal, and their second major source of energy was nuclear power. Renewable energy sources, except for hydroelectric power, were 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 was that the majority of nonutility capacity was 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.

As of December 1991, the process of change in the structure of the electric power industry had not yet run its course. Major issues arose, including the effect of the changing industry structure on the reliability of electric power supply and on bulk (wholesale) power trade. Also at issue was whether the Clean Air Act Amendments of 1990 (CAAA90) would alter the course of nonutility growth.

The concern with the CAAA90 centered on whether nonutilities would 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.

Conclusion

This appendix has summarized the past 100 years with respect to the history of the electric power industry. The following appendix provides an interesting look at milestones in the history of the industry.

[198]Energy Information Administration, *Annual Energy Review 1984*, DOE/EIA-0384(84) (Washington, DC, July 1985), pp. 171, 179, 181, 187.

[199]Reprinted from *The Changing Structure of the U.S. Electric Power Industry, 1970-1991*, DOE/EIA-0562 (Washington, DC, March 1993), pp. vii-ix.

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

Appendix C

Pending Federal Restructuring Legislation

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Pending Federal Restructuring Legislation

(As of May 1, 2000)

106th Congress House of Representatives Bills

H.R. 341
Environmental Priorities Act of 1999
Introduced on January 19, 1999 by Representative Robert Andrew (D-NJ).

- Gives the Environmental Protection Agency (EPA) the authority to establish a National Environmental Priorities Board, and requires the EPA Administrator to promulgate a final rule containing the rules and procedures of the Board. The Board is to support State environmental projects, and may include loans, loan guarantees, grants, capitalization grants, and other assistance.

- Mandates that retail electric service providers must contribute 10 percent of the total consumer savings to the Environmental Priorities Board once retail electric service choice has been established.

H.R. 667
The Power Bill
Introduced by Representative Richard Burr (R-NC) on February 10, 1999.

- Clarifies States' authority to order retail wheeling and imposes reciprocity requirements with respect to sales of electricity by out-of-state entities.

- Grants cooperatively owned sellers or distributors of electricity the right to engage in any activity or provide any service lawfully carried out by any other seller or distributor of electricity in the State.

- Authorizes a State or State regulatory authority to impose charges upon purchases of retail electric energy services, including fees: (1) to recover costs incurred by an electric utility that become unrecoverable due to the availability of retail electric service choice; (2) to pay all reasonable costs associated with governmental requirements regarding decommissioning of nuclear generating units; and (3) to fund public benefit programs.

- Declares that, as of January 1, 1999, new electric utility contracts for purchase or sale shall no longer be subject to cost provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978. Additionally, authorizes recovery of all costs associated with prior contracts involving purchases of electric energy or capacity from a cogeneration and small power production facility by electric utilities.

- Repeals the Public Utility Holding Company Act of 1935. Prescribes guidelines for Federal and State access to books and records of electric utility holding companies and their affiliates to ensure consumer rate protection.

- Requires State laws or regulations for the recovery of stranded costs to be filed with FERC as a prerequisite to State receipt of Federal energy assistance. Precludes any modification or repeal of such laws or regulations for 7 years after such filing date.

- Instructs the Secretary of Energy to present a status report (2 years after enactment of proposed legislation) to the Congress on the extent to which State actions have removed regulatory and statutory barriers to interstate commerce in electricity.

H.R. 721
Bond Fairness and Protection Act of 1999
Introduced by Representative J.D. Hayworth (R-AZ) on February 11, 1999.

- Amends the Internal Revenue Code of 1986 (with respect to tax-exempt bond financing of certain electric facilities) to exclude a permitted open access transaction (as defined by this Act) from the definition of private business use.

- Grants public power utilities the option of grandfathering outstanding tax-exempt debt subject to abrogating issuing tax-exempt bonds to finance new facilities in the future. Alternatively, they may continue to issue tax-exempt bonds subject to current private use limitations in the tax code.

H.R. 971
Electric Power Consumer Rate Relief Act of 1999
Introduced by Representative James Walsh (R-NY) on March 3, 1999.

- Amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to provide that a State regulatory authority may ensure that rates charged by qualifying small power producers and qualifying cogenerators to purchasing utilities are (1) just and reasonable to consumers of the purchasing utility and (2) do not exceed the incremental cost to the purchasing utility of alternative electric energy and capacity at the time of delivery.

- Grants States the ability to establish programs for monitoring the operating and efficiency performance of in-state cogeneration and small power production facilities to determine whether such facilities meet FERC standards for qualifying cogenerators.

- Allows a State regulatory authority to require that any contract entered into before the enactment date of proposed legislation be amended to conform to the requirements governing rates to retail customers.

H.R. 1138
Ratepayer Protection Act
Introduced by Representative Cliff Stearns (R-FL) on March 16, 1999.

- Mandates that the Public Utility Regulatory Policies Act of 1978 (PURPA) requirement that electric utilities enter into contracts to purchase electricity from certain cogeneration and small power production facilities shall expire after January 6, 1999.

- Mandates that all power purchase contracts which were in effect up to January 6, 1999 be honored.

- Directs the Federal Energy Regulatory Commission (FERC) to ensure that utilities are not required to absorb costs associated with electric energy or capacity purchases executed prior to the enactment of proposed legislation.

H.R. 1253
A Bill to Amend the Internal Revenue Code of 1986 to Restrict the Use of Tax-Exempt Financing by Governmentally Owned Electric Utilities and to Subject Certain Activities of Such Utilities to Income Tax
Introduced by Representative Phillip English (R-PA) on March 24, 1999.

- Narrows the Internal Revenue Tax Code definition of circumstances under which governmentally owned electric utilities may finance utility facilities with tax-exempt bonds.

- Subjects utility-related income of governmental entities to Federal income tax in situations where the income is derived from sources outside their specified service area.

H.R. 1486
Power Marketing Administration Reform Act of 1999
Introduced by Representative Bob Franks (R-NJ) on April 20, 1999.

- Requires the Secretary of Energy to develop and implement procedures to ensure that the Federal Power Marketing Administrations (FPMAs) utilize the same accounting principles and requirements as the Federal Energy Regulatory Commission (FERC).

- Requires each FPMA and the Tennessee Valley Authority (TVA) to submit periodically, for FERC review, rates for the sale or disposition of Federal energy that will ensure recovery of all their costs in generating and marketing such energy.

- Prescribes rate mechanism and pricing guidelines.

- Establishes a fund within the Department of the Interior to (1) mitigate damage to environmental resources attributable to power generation and sales facilities, and (2) restore the health of such resources, including fish and wildlife. Mandates project-specific mitigation plans for each power generation project.

- Establishes a fund within the Department of Energy for renewable resources. Prescribes expenditure guidelines.

- Mandates that public bodies and cooperatives be given a preference for future power allocations or reallocations of Federal power through a right of first refusal at market prices.

- Instructs the Secretary of Energy to require each FPMA to (1) assign personnel and incur expenses solely for authorized power marketing, reclamation, and flood control activities, and not for diversification into ancillary activities; and (2) make annual public disclosures of its activities, including the full costs of power projects and marketing.

- Precludes an FPMA from entering into or renewing any power marketing contract for a term exceeding 5 years.

- Requires provision of FPMA transmission services on an open access basis, and at FERC-approved rates in the same manner as provided by any public utility under FERC jurisdiction.

- Grants FERC rate-making approval authority until a full transition is made to market-based rates, for (1) rate schedules recommended by the Secretary of Energy; and (2) rate schedules for FPMA power sales.

- Amends: (1) the Department of Energy Organization Act to reflect the changes made by this Act; and (2) specified Federal law to repeal the prohibition against the use of appropriated funds for purposes relating to the possibility of changing from an “at cost” to a “market rate” or any other noncost-based method for pricing Federal hydroelectric power.

H.R. 1587
Electric Energy Empowerment Act of 1999
Introduced by Representative Cliff Stearns (R-FL) on April 27, 1999.

- Amends the Federal Power Act (FPA) to empower the States to order electric utilities within their jurisdiction to provide nondiscriminatory open access through functionally unbundled transmission and local distribution services to retail customers within their borders. Prescribes implementation guidelines.

- Allows States or State regulatory authorities to impose charges for recovery of stranded costs to ensure reliability and availability of electric supply, to support low-income residential programs, to retrain electric employees, to fund environmental programs, and to provide payment for reasonable costs associated with nuclear decommissioning.

- Amends FPA by placing the State in charge of regulation of bundled electric retail sales and unbundled local distribution service.

- Authorizes FERC to distinguish, after consulting with appropriate State regulatory authorities, between facilities used for transmission and delivery that are subject to FERC approval and those subject to State jurisdiction.

- Encourages creation of Independent Transmission System Operators to ensure that all sellers and buyers of electricity have access to nondiscriminatory transmission services.

- Requires public power utilities to conform to open access requirements currently applied to private power utilities.

- Repeals mandatory power purchase contract requirements set forth in the Public Utility Regulatory Policies Act of 1978 and allows for recovery of stranded costs.

- Repeals the Public Utility Holding Company Act of 1935.

- Authorizes Federal and State authorities access to books and records of all companies in a holding company system and for Federal oversight of affiliate transactions for the purpose of protecting consumers with respect to rates.

- Advocates the formation and operation of an Electric Reliability Council to ensure that competitive restructuring of the electricity industry does not lessen reliability of the electric supply. Prescribes guidelines for formation, membership, funding, and governance.

H.R. 1828
Comprehensive Electricity Competition Act
Introduced by Representative Tom Bliley (R-VA) on May 17, 1999.

- Provides a flexible mandate for States to require open access to the distribution facilities of regulated and non-regulated electric utilities. Allows State-regulated and non-regulated utilities to "opt out" of retail competition if, after a hearing before the State regulatory authority, it is determined that retail competition will have a negative impact on certain customer classes.

- Grants to any person the ability to bring an action, in the appropriate State court, against a State regulatory authority or distribution utility for failure to comply with open access requirements.

- Eliminates private use limitations on outstanding bonds for publicly owned facilities used in connection with retail competition or open access transmission. Ends the issuance of new tax-exempt bonds for generation or transmission. Continues availability of tax exempt bonds for distribution facilities under current law.

- Allows States and non-regulated utilities to determine the amount of recoverable stranded costs. Grants FERC authority to establish stranded cost recovery in the absence of State authority.

- Grants FERC authority to oversee creation of Independent Regional System Operators (IRSOs) and to compel utilities to turn over control of their transmission facilities to such organizations.

- Encourages regional agreements that facilitate coordination among States with regard to siting and planning of transmission and generation facilities; calls for FERC approval of such agreements.

- Creates a renewable portfolio system mandating that power sellers use a percentage of non-hydro electric renewable technology. Sets forth requirements of sale and purchase of renewable energy credits and stipulates use of revenue from such sales.

- Authorizes FERC, upon petition by a State, to require generators to submit a plan mitigating market power which FERC can accept or modify. Clarifies FERC merger review over generation-only companies and holding companies.

- Requires FERC to approve and oversee an organization that prescribes and enforces mandatory reliability standards.

- Clarifies the authority of the Environmental Protection Agency to require an interstate trading system for the purpose of reducing nitrogen oxide pollution.

- Creates a Public Benefits Fund for low-income assistance, energy efficiency programs, consumer education, and development of emerging technologies. Stipulates funding mechanisms and sets forth guidelines of operation.

- Repeals the Public Utility Holding Company Act of 1935 (PUHCA) 18 months after enactment of proposed legislation. Grants FERC and States access to utility books and records.

- Eliminates obligatory power purchase contracts mandated in the Public Utility Regulatory Policies Act of 1978 on the date of enactment of proposed legislation.

- Places Tennessee Valley Authority (TVA) transmission under FERC jurisdiction. Subjects power wheeled through TVA to open access requirements and allows wholesale electric power sales by TVA outside of their traditional service area. Calls for the renegotiation of long-term contracts and authorizes FERC to intervene if conflict arises. Authorizes TVA to join an Independent System Operator.

- Authorizes FERC to determine transmission rates for the Bonneville Power Administration, Western Area Power Administration, and the Southwestern Power Administration, and allows these Federal Power Administrations to impose a surcharge on sales to recover costs of environmental programs and to join IRSOs.

- Provides States that have implemented retail competition with the authority to preclude an out-of-state utility with a retail monopoly from selling within the State unless that out-of-state utility permits customer choice.

- Requires States electing retail competition to establish terms and conditions to protect consumers, including rates that are just and reasonable, measures to ensure privacy of consumer information and that prohibit discriminatory practices by electric utilities. Allows States to impose non-bypassable fees to fund such programs. Authorizes creation of a publicly accessible database that will provide information to consumers on electric utilities which participate in retail competition.

- Amends PURPA by allowing net metering for renewable energy and granting tax credits for production of energy from renewable resources and production of energy efficient buildings.

- Grants customers the ability to acquire retail electric energy on an aggregate basis if the group of customers is served by one or more local distribution companies which sell electricity on a competitive basis.

- Authorizes the provision of grant money for assistance purposes to tribal Indians, Southeast Alaska, and rural and remote communities.

- Eliminates antitrust review by the Nuclear Regulatory Commission and amends the Internal Revenue Code relating to deductions to a qualified nuclear decommissioning fund.

H.R. 2050
Electric Consumers' Power to Choose Act of 1999
Introduced by Representative Steve Largent (R-OK) on June 8, 1999.

- Accords States a flexible mandate in terms of retail competition. States may choose to implement retail electric competition for their regulated distribution systems, or choose to opt out if retail competition would negatively impact customers. Nonregulated local distribution companies are also provided with a similar flexible mandate to establish or opt out of retail competition.

- Grandfathers State plans already underway or on the books and provides a reciprocity provision to keep out companies whose territories are not open to competition. Similar plans adopted by non-regulated local distribution companies will also be grandfathered.

- Amends tax laws to permit public power and municipal utilities to participate in open access plans without forfeiting the tax-exempt status of their outstanding bonds.

- Permits States and nonregulated utilities to bar those who have not elected retail choice from selling to electric customers in their State or utility service regions.

- Allows a group of electric customers to buy retail electricity on an aggregate basis if they are served by one or more electric utilities in consumer choice regions.

- Provides that States will have jurisdiction over disputes arising from States' or nonregulated utilities' actions in electing to move to retail competition.

- Directs the Federal Trade Commission to establish rules and penalties to protect consumers from unfair trade practices by electricity suppliers.

- Amends the Federal Power Act (FPA) to require that electric suppliers and transmitting utilities join an Electric Reliability Organization subject to FERC approval and oversight. Protects such organizations from the provisions of anti-trust laws.

- Allows small-scale power generators to interconnect with local distribution utilities to facilitate supplies that are closer to end-use requirements.

- Directs FERC to determine the exercise of market power by an electric utility and to initiate mitigation measures where necessary.

- Extends FERC's authority over transmission facilities of electric utilities to include facilities of State and municipal utilities, rural electric cooperatives, and facilities that qualify under the Public Utility Regulatory Policies Act of 1978, thus enabling the Commission to set transmission rates for all utilities in the country.

- Clarifies State and Federal authority over bundled and unbundled retail electric sales by granting FERC exclusive regulatory authority over the transmission component of an unbundled retail sale.

- Provides FERC with the authority to establish Regional Transmission Organizations (RTOs) by requiring that all transmitting utilities transfer operational control or ownership of their transmission facilities to such an organization.

- Authorizes FERC to order the BPA and the Electric Reliability Council of Texas to wheel power.

- Requires FERC to review mergers and property dispositions involving generation-only companies and holding companies.

- Encourages regional agreements that facilitate coordination among States with regard to siting and planning of transmission and generating facilities subject to approval by FERC of such agreements.

- Requires States electing retail competition to establish terms and conditions to protect consumers, including rates that are just and reasonable, measures to ensure privacy of consumer information and that prohibit discriminatory practices of electric utilities. Allows States to impose non-bypassable fees to fund such programs.

- Exempts holding companies from limitations of the Public Utility Holding Company Act of 1935 eighteen months after enactment of proposed legislation unless they provide retail service in two or more States that do not provide open access. Grants FERC and States access to utilities' books and records to assist regulatory authorities in carrying out their functional responsibilities.

- Prospectively repeals the Public Utility Regulatory Policies Act of 1978 and eliminates obligatory power purchase contracts. Allows for recovery of stranded costs with respect to purchases from outstanding contracts.

- Places TVA transmission under FERC jurisdiction. Subjects power wheeled through TVA to open access requirements and sets limitations on electric power sales by TVA. Prohibits the acquisition of new generating resources and calls for the renegotiation of long-term contracts. Repeals TVA's jurisdiction to regulate municipality or cooperative organization distributors and removes TVA's PURPA ratemaking authority. Allows for imposition of charges for the purpose of stranded cost recovery.

- Subjects BPA to relevant provisions of the FPA for purposes of BPA's transmission systems, but provides that any determination by FERC would be subject to a list of conditions, including a requirement that the rates and charges are sufficient to recover existing and future Federal investment in the Bonneville Transmission System. Requires FERC to establish a rate recovery mechanism to meet BPA's cost recovery requirements.

- Subjects Power Marketing Administrations (PMAs) to the same accounting principles used by other public utilities and applicable antitrust laws and authorizes PMAs to participate in FERC-approved RTOs.

- Mandates a renewable portfolio generation minimum standard of 3 percent of total generation and sets forth enforcement procedures for noncompliance. Directs the Secretary of Energy to establish a program to issue, monitor the sale and exchange of, and track Renewable Energy Credits.

- Amends the Public Utility Regulatory Policies Act of 1978 by allowing net metering for renewable energy, and granting tax credits for production of energy from renewable resources and production of energy efficient buildings.

H.R. 2363
Public Utility Holding Company Act of 1999
Introduced by Representative W.J. (Billy) Tauzin (R-LA) on June 25, 1999.

- Repeals the Public Utility Holding Company Act of 1935.

- Enacts the Public Utility Holding Company Act of 1999 to support the continuing need for limited Federal and State regulation and to supplement the work of State commissions for the continued rate protection of utility customers.

H.R. 2569
Fair Energy Competition Act of 1999
Introduced by Representative Frank Pallone, Jr. (D-NJ) on July 20, 1999.

- Aims that older and more polluting power generating units internalize pollution costs on par with newer and less polluting generation units.

- Requires FERC to (1) calculate generation performance standards for nitrogen oxides, carbon dioxide, mercury, sulfate fine particulate matter, and any other significant air pollutant released in significant quantities by electric generating units from covered generating units, (2) set forth schedules of statutory tonnage caps for electric generation emissions of nitrogen oxides, carbon dioxide, mercury, and sulfate fine particulate matter, and (3) promulgate, by rule, a national limit on total annual emissions of any other pollutant from electric generating units.

- Prescribes rules for allocation and trading of allowances and sets penalties for excess emissions.

- Mandates that, during periods when National Ambient Air Quality Standards for ozone are exceeded, certain generating units shall be required to "adjust (their) reported actual emissions."

- Amends the Federal Power Act to require the Commission to provide estimates of electricity generation from covered electric generation units with projections of demand growth for regions and time periods specified in the legislation.

- Directs the Secretary of Energy to establish a National Electric System Public Benefits Board authorized to collect wires charges to fund public purpose programs including renewable sources, universal / affordable electric service, energy conservation and efficiency programs, research and development programs, and assistance to low-income families.

- Creates a renewable energy portfolio (to become effective upon the enactment of proposed legislation) that mandates renewable electricity generation to increase from 2.5 percent in 2000 to 7.5 percent in 2010. Authorizes FERC to sell renewable energy credits (that equal the number of megawatthours of electricity from renewables) and to utilize proceeds to fund research and development of renewables and cleaner burning fuels.

- Amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to net metering to producers of renewable electricity and sets guidelines for interconnection to the grid. Also, stipulates disclosure requirements of emissions and generation data with respect to sales of electricity to consumers.

- Eliminates obligatory power purchase contracts mandated in PURPA on the date of enactment of proposed legislation without invalidating the sanctity of existing contracts.

- Sets forth terms and conditions to protect consumers (including privacy and non-discriminatory measures) and sets penalties for violations.

H.R. 2602
National Electricity Interstate Transmission Reliability Act
Introduced by Representative Albert Wynn (D-MD) on July 22, 1999.

- Amends the Federal Power Act to accord FERC jurisdiction over an electric reliability organization (ERO), affiliated regional reliability entities, system operators, and users of the bulk-power system for enforcing compliance with respect to transmission reliability standards.

- Prescribes procedures that enable FERC to approve reliability standards (subject to the requirement that the standards are nondiscriminatory and in the public interest) for the bulk-power system and to approve an entity's application to function as an ERO contingent on its capability to meet criteria listed in the proposed legislation.

- Authorizes FERC to take disciplinary action against those violating organizational reliability standards.

H.R. 2645
Electricity Consumer, Worker, and Environmental Protection Act of 1998
Introduced by Representative Dennis Kucinich (D-OH) on July 29, 1999.

- Prescribes standards for electricity services at the State and Federal levels.

- Provides protections for electric utility workers whose companies are undergoing transfer of ownership as a result of restructuring.

- Ensures consumers' right to privacy with respect to billing, payments, usage, and dispute resolution.

- Mandates that each State create a not-for-profit membership corporation to represent and promote the interests of States' residential electricity consumers.

- Requires each provider of distribution services and supplies to submit monthly reports to monitor performance and reliability to help protect consumers.

- Establishes within the Federal Energy Regulatory Commission an office of the Consumer Council to represent energy consumers.

- Prohibits State or Federal authorities from imposing a stranded cost recovery burden on existing consumers.

- Sets limits with respect to affiliate ownership on State-regulated investor-owned utilities.

- Directs that utilities set aside adequate financial resources to meet the costs of nuclear decommissioning and waste disposal activities.

- Reinforces FERC's authority to review electric utility mergers.

- Requires the Environmental Protection Agency to promulgate regulations establishing nationwide pollution standards together with pollutant monitoring procedures.

- Establishes a National Electric Public Benefit Board to provide funds (gathered through the imposition of a wires charge) to States for low-income assistance programs.

- Establishes renewable energy portfolio standards for electricity generation to reach 8 percent in the year 2010 (increasing by 1 percent annually thereafter) by requiring the Secretary of Energy to implement the standards in accordance with the provisions of the proposed legislation.

- Amends the Public Utility Regulatory Policies Act of 1978 to provide net-metering and interconnection facilities for renewable energy, where necessary.

- Sets deadlines for States to comply with the requirements of this Act subsequent to their deregulating retail electricity sales.

- Directs States not to permit customer classes to be charged rates for transmission and distribution in excess of their proportional responsibility for providing these services.

- Requires that utilities transfer their transmission and distribution assets to regulated counterparts/affiliates after deregulation of electricity sales at the retail level. Also, provides detailed guidelines to prevent affiliate abuse and cross-subsidization.

- Limits utilities' ownership of power plants to prevent exercise of market power in electricity generation.

- Sets forth post-deregulation requirements for compliance in areas such as the provision of basic services, aggregation of customers, worker protection, and rules for electricity suppliers and distribution companies.

- Prohibits unfair business practices and stipulates norms to protect the consumers in billing, metering, and in securing credit. Remedies for violation are also provided.

H.R. 2756
Fair Competition in Tax-Exempt Financing Act of 1999
Introduced by Representative Ralph Hall (D-TX) on August 5, 1999.

- Amends the Internal Revenue Code of 1986 by eliminating the issuance of tax-exempt bonds to finance public projects to prevent governmental entities from using tax-exempt financing to engage in unfair competition against private sector facilities.

H.R. 2786
Interstate Transmission Act
Introduced by Representative Thomas Sawyer (D-OH) on August 5, 1999.

- Expands the definition of interstate commerce in electricity to include unbundled transmission of electricity sold at the retail level under FERC's jurisdiction (in addition to transmission at the wholesale level) and directs FERC to determine which facilities used in interstate commerce will be subject to FERC's jurisdiction and which facilities will be subject to the State's jurisdiction.

- Authorizes FERC to permit a transmitting utility to recover all costs incurred in connection with the transmission and associated services including the costs of expansion of transmission networks.

- Directs FERC to establish just and non-discriminatory rates that promote efficient transmission and network expansion to avoid cost shifting among customer classes.

- Directs FERC to promote and approve the voluntary formation of regional transmission organizations.

- Entrusts FERC with the responsibility to ensure that transmitting utilities and their customers comply with reliability standards adopted by electric reliability organizations.

H.R. 2944
Electricity Competition and Reliability Act
Introduced by Representative Joseph Barton (R-TX) on September 24, 1999.

- Gives priority to State laws that are passed up to 3 years after enactment of proposed legislation that address concerns proffered by proposed legislation.

- Amends the Federal Power Act (FPA) to clarify States' authority to require retail competition and to clarify State and Federal jurisdiction. Gives States the authority to impose fees to fund public purpose programs.

- Amends the FPA to require open access for all transmitting utilities and to provide transmission service at nondiscriminatory prices. Grants FERC authority over the transmission systems at the State, municipal and rural cooperative level, and allows FERC to review transmission rates.

- Grants FERC the power to determine which transmission facilities compose the bulk power system (and fall under FERC's jurisdiction) and which are exempt from FERC regulations.

- Allows FERC to recover wholesale stranded costs where necessary.

- Amends the FPA to permit FERC to order domestic transmission service to be used for a foreign country.

- Encourages the formation of RTOs. Provides standards that RTOs must meet and authorizes FERC to approve RTOs. Allows Federal transmitting utilities to participate in RTOs with Congressional consent. Protects RTOs formed prior to enactment of legislation from mandatory modifications directed by FERC.

- Amends the FPA to grant Congressional consent to regional transmission siting to ameliorate problems encountered by States in planning for future transmission. Authorizes FERC to review compacts to protect the public's interest.

- Authorizes FERC to order a transmitting utility to expand its transmission facilities (if it would not unreasonably harm the services provided by the utility), but retains State and local authority over transmission siting.

- Amends the FPA by allowing transmission utilities to recover costs incurred to encourage additional investment in transmission. Directs FERC to approve transmission rates that are high enough to ensure the expansion of transmission networks.

- Directs FERC to encourage transmission pricing policies that encourage RTO formation, reduce pancaking of rates, minimize cost shifting among customer classes, encourage reliability of the transmission system, and encourage investment in the transmission system. Authorizes FERC to approve transmission rates and requires FERC to submit a report to Congress on these issues.

- Amends the FPA to allow FERC to impose civil penalties for non-compliance with FPA regulations. Permits Federal agencies to file complaints with FERC and seek rehearing of FERC orders.

- Amends the FPA to allow FERC jurisdiction over an ERO, affiliated regional reliability entities, and bulk power system users and operators to ensure reliability. Calls for FERC review of ERO standards and provides guidelines for the ERO's operation.

- Provides consumer protection measures that address information disclosure issues, consumer privacy practices, unfair trade practices, and express the consensus that electric services should be universal and affordable.

- Expands FERC merger review authority to include all electric utilities and transmitting utilities. Eliminates antitrust review by the Nuclear Regulatory Commission for production facilities.

- Repeals the Public Utility Holding Company Act of 1935. Allows FERC and the State access to records of holding and associate companies to identify costs and to protect utility consumers' rates.

- Prospectively repeals the Public Utility Regulatory Policies Act of 1978 and allows for cost recovery of purchases made prior to enactment of proposed legislation.

- Allows retail customers to designate an entity to aggregate purchases of electric energy.

- Amends the FPA to require local distribution companies to interconnect distributed generation facilities with the local distribution facilities.

Grants FERC the ability to order interconnection and establish safety standards.

- Prohibits TVA from selling electric power at the retail level with certain exceptions. Allows TVA to only sell excess electric power and limits TVA's contract offerings to new customers. Places TVA under the same standards for wholesale sales in interstate commerce as public utilities. Authorizes TVA to build or acquire additional generation facilities, if needed, and directs TVA to renegotiate existing all-requirements power contracts. Allows stranded cost recovery by TVA.

- Provides that FERC determine transmission rates, terms, and conditions to assure BPA adequately recovers costs, protects customers from cost shifting, and provides transmission access.

- Grants FERC statutory authority to approve and modify Power Marketing Administration (PMA) wholesale rates to guarantee full cost recovery. Applies provisions of the FPA to the transmission of electric energy by PMAs, and subjects PMAs to antitrust laws

- Reauthorizes and expands the Renewable Energy Production Incentive program established by the Energy Policy Act of 1992. Requires retail electric suppliers to provide net metering services. Maintains States' authority to set Renewable Energy Portfolio standards.

- Directs the Department of Energy to present a report to Congress on interstate commerce in electric energy and identify regulatory and statutory barriers. Directs FERC to study State regulation of transmission sales and report the results to Congress.

H.R. 2947
Home Energy Generation Act
Introduced by Representative Jay Inslee (D-WA) on September 24, 1999.

- Amends the Federal Power Act to allow for net metering. Requires retail electric suppliers to make electric energy meters available (if necessary) to consumers who have installed an energy generating unit capable of net metering.

- Protects against discrepancies in rates and contract terms between net metering customers and customers who do not participate in net metering.

- Attributes energy generated through net metering that is entitled to receive credits under a Federal minimum energy portfolio to the retail electric supplier and allows the retail supplier to count these credits towards requirements for renewable resources.

- Prescribes guidelines and procedures for the calculation of net metering and for the purposes of monitoring, billing, and providing consumer protection.

- Places limits on the amount of allowable net metering that a local distribution company retail electric supplier is required to provide.

- Calls for open public documentation of total generating capacity, type of unit, and energy source(s) of consumer-owned generating units.

- Provides consumer protection measures and sets performance and safety standards for use in net-metering and interconnection to the electrical grid.

106th Congress Senate Bills

S. 161
Power Marketing Administration Reform Act of 1999
Introduced by Senator Daniel Moynihan (D-NY) on January 19, 1999.

- Directs the Secretary of Energy to develop and implement cost accounting procedures to ensure that the Federal Power Marketing Administrations (FPMAs) and TVA use the same accounting principles and requirements that FERC applies to the electric operations of public electric utilities.

- Mandates that the FPMAs and TVA implement rate-adjusting procedures to allow for full cost recovery of power they sell while transitioning to market-based rates set by an open market.

- Requires FPMAs and TVA to develop and submit to FERC, once every 5 years, proposed rates that ensure recovery of all costs of generation and marketing of power (including fish and wildlife related costs) for approval and / or modification.

- Empowers the Secretary of Energy to establish procedures enabling FPMAs and the TVA to implement market-based pricing 2 years after the enactment of legislation using bid and auction procedures.

- Prescribes specifics regarding use of revenue collected through market-based pricing including, among others, environmental mitigation and restoration, renewable resource development, and utilization of potential surpluses to reduce the budgetary deficit.

- Precludes an FPMA or TVA from entering into or renewing any power marketing contract for a term exceeding 5 years from the date of enactment of proposed legislation.

- Directs that FPMAs and the TVA provide transmission service on an open access basis at just and reasonable rates approved by FERC.

S. 282
Transition to Competition in the Electric Industry Act
Jointly introduced by Senators Connie Mack (R-FL) and Bob Graham (D-FL) on January 21, 1999.

- Prospectively repeals mandatory power purchase requirements (from cogenerators and small power producers) by the electric utilities as required by Section 210 of the Public Utility Regulatory Policies Act of 1978.

- Ensures recovery of power purchase contract costs incurred by electric utilities prior to the enactment of proposed legislation.

S. 313
Public Utility Holding Company Act of 1999
Introduced by Senator Richard Shelby (R-AL) on January 27, 1999.

- Repeals the Public Utility Holding Company Act (PURPA) of 1935.

- Ensures rate protection of utility customers by empowering State and Federal regulatory authorities with tools which permit access to the books and records of holding companies for the purpose of jurisdictional rate-setting activities.

- Grants the Federal Energy Regulatory Commission additional enforcement authority under the Federal Power Act to permit implementation of provisions of proposed legislation.

S. 386
Bond Fairness and Protection Act of 1999
Introduced by Senator Slade Gorton (R-WA) on February 6, 1999.

- Amends the Internal Revenue Code by eliminating restrictions placed on public utilities which prevent the reciprocal provision of open access transmission and ancillary services required by FERC Order 888.

- Grants public power utilities the option of grandfathering outstanding tax-exempt debt subject to abrogating issuing tax-exempt bonds in the future to finance new facilities. Alternatively, they may continue to issue tax-exempt bonds subject to current private use limitations in the tax code.

S. 516
Electric Utility Restructuring Empowerment and Competitiveness Act of 1999
Introduced by Senator Craig Thomas (R-WY) on March 3, 1999.

- Empowers States to regulate intrastate retail electric supply or distribution service, establish and enforce reliability standards, determine just and reasonable fees where appropriate, and to enforce open transmission and provision of universal service.

- Grants FERC jurisdiction over wholesale electricity transmission services, but removes sales of wholesale electricity from the scope of FERC regulation.

- Amends PURPA to exempt electric utilities from obligatory contracts with cogenerating facilities or small power producers.

- Repeals PUHCA.

- Allows FERC and the States access to and disclosure of holding company management and affiliate rate recovery records. Authorizes appropriations and calls on FERC to promulgate final rules of exemption from PUHCA.

S. 1047
Comprehensive Electricity Competition Act
Introduced by Senator Frank Murkowski (R-AK) on May 13, 1999.

- Amends PURPA to require each distribution utility to permit all of its retail customers to purchase power from the supplier of their choice by January 1, 2003, but provides a flexible mandate for States to require open access to the distribution facilities of regulated and non-regulated electric utilities. Allows State-regulated and non-regulated utilities to "opt out" of retail competition if, after a hearing before the State regulatory authority, it is determined that retail competition will have a negative impact on certain customer classes.

- Allows States and non-regulated utilities to determine the amount of recoverable stranded costs. Grants FERC authority to establish stranded cost recovery in the absence of State authority.

- Amends PURPA to permit a State that has chosen to implement retail competition to prohibit a distribution utility that is not under the rate-making authority of the State and that has not elected to institute retail competition from selling electricity to the consumers of the State that has chosen retail competition. Grants non-regulated utilities similar requirements of reciprocity.

- Allows electricity customers and entities acting on their behalf to acquire retail electric energy on an aggregate basis if they are served by one or more distribution utilities for which a notice of retail competition has been filed.

- Requires States electing retail competition to establish terms and conditions to protect consumers, including rates that are just and reasonable, measures to ensure privacy of consumer information and that prohibit discriminatory practices by electric utilities. Allows States to impose non-bypassable fees to fund such programs. Authorizes the creation of a publicly accessible database that will provide consumers information on electric utilities that participate in retail competition.

- Clarifies State and Federal authority over retail transmission services. Expands FERC's jurisdiction to include authority over unbundled retail transmission and municipal and publicly owned utilities and cooperatives. Reinforces FERC's authority to require public utilities to provide open access transmission services and permit recovery of stranded costs.

- Grants FERC authority to oversee creation of IRSOs and to compel utilities to turn over control of their transmission facilities to such organizations.

- Creates a Public Benefits Fund for low-income assistance, energy efficiency programs, consumer education, and development of emerging technologies. Stipulates funding mechanisms and sets forth guidelines for operation.

- Creates a renewable portfolio system mandating that sellers use, as a generation source, a percentage of non-hydro electric renewable technology. Sets forth requirements of sale and purchase of renewable energy credits and stipulates use of revenue from such sales.

- Amends PURPA by allowing net metering for renewable energy, and granting tax credits for production of energy from renewable resources and production of energy efficient buildings.

- Eliminates obligatory power purchase contracts mandated in the Public Utility Holding Company Act of 1935 (PUHCA) on the date of enactment of proposed legislation.

- Amends PURPA to require a distribution utility to allow a heat and power or a distributed power facility to interconnect with it if the facility is located within the distribution utility's service territory and complies with rules issued by the Secretary of Energy and related safety and power quality standards.

- Authorizes the provision of grant money for assistance purposes to tribal Indians, Southeast Alaska, and rural and remote communities.

- Repeals PUHCA 18 months after enactment of proposed legislation. Grants FERC and States access to utilities' books and records.

- Authorizes FERC, upon petition by a State, to require generators to submit a plan mitigating market power that FERC can accept or modify. Clarifies FERC merger review over generation-only companies and holding companies.

- Allows FERC to approve and oversee an ERO to prescribe and enforce mandatory reliability standards.

- Clarifies the authority of the Environmental Protection Agency to require a nitrogen oxide (NO_x) allowance cap and trading program in all States in which a NO_x emission source is located.

- Places TVA transmission under FERC jurisdiction. Subjects power wheeled through TVA to open access requirements and allows wholesale electric power sales by TVA outside of their traditional service area. Calls for the renegotiation of long-term contracts and authorizes FERC to intervene if conflict arises. Authorizes TVA to join an Independent System Operator.

- Authorizes FERC to determine transmission rates for the BPA, Western Area Power Administration (WAPA), and the Southwestern Power Administration (SWPA) and allows these Federal Power Administrations to impose a surcharge on sales to recover costs of environmental programs and to join IRSOs.

- Eliminates antitrust review by the Nuclear Regulatory Commission and amends the Internal Revenue Code relating to deductions to a qualified nuclear decommissioning fund.

S. 1048
Comprehensive Electricity Competition Tax Act
Introduced by Senator Frank Murkowski (R-AK) on May 13, 1999.

- Amends the Internal Revenue Code with respect to tax-exempt private activity bonds to declare that the determination whether any electric output facility bond issued before enactment of this Act (pre-effective date electric output facility bond) is a private activity bond shall be made without regard to any specified permissible competitive action taken by the issuer. Requires such a bond not to be a private activity bond or industrial development bond as of the date of enactment of this Act. Makes this Act inapplicable to any qualified refunding bond meeting certain criteria which is issued to refund a pre-effective date electric output facility bond if the net proceeds of the refunding bond are used within 90 days of issuance to redeem the refunded bond.

- Qualifies for tax exemption private activity bonds for electric output facilities issued after enactment of this Act, excluding any part of an issue for distribution property that operates at 69 kilovolts or less.

- Modifies special rules for nuclear decommissioning costs to eliminate cost-of-service as the maximum which a taxpayer may pay into a Nuclear Decommissioning Fund.

- Includes any distributed power property within 15-year depreciation property.

- Establishes an 8-percent investment credit for combined heat and power (CHP) systems property placed in service in calendar years 2000 through 2002. Precludes any carryback of the energy credit prior to the effective date of this Act, except for solar and geothermal energy property.

S. 1273
Federal Power Act Amendments of 1999
Introduced by Senator Jeffrey Bingaman (D-NM) on June 24, 1999.

- Expands the jurisdiction of FERC to order retail wheeling to facilitate transition to competition in power generation.

- Preserves authority of States (and of their regulatory commissions) to require that jurisdictional utilities provide unbundled local distribution service on a nondiscriminatory basis to customers within the State.

- Sustains States' authority to impose charges on retail electricity distribution and power generation.

- Directs FERC to establish and enforce reliability standards for transmission purposes and grants FERC the authority to set up the required infrastructure.

- Empowers FERC to order a transmitting utility to enlarge, extend, or improve its transmission facilities.

- Authorizes FERC to order the formation of regional transmission systems and regional independent system operators to ensure nondiscriminatory transmission availability within a region by securing the participation of all transmitting utilities within regions so formed.

- Protects existing wholesale power purchase contracts and preempts any State action that would bar recovery of associated costs by electric utilities.

S. 1284
Electric Consumer Choice Act
Introduced by Senator Don Nickles (R-OK) on June 24, 1999.

- Amends the Federal Power Act to ensure that no State may establish, maintain, or enforce on behalf of any electric utility an exclusive right to sell electric energy or otherwise unduly discriminate against any consumer who seeks to purchase electric energy in interstate commerce from any supplier.

- Stipulates that no electricity suppliers shall be denied access to transmission and local distribution facilities or be precluded from participating in retail sales on grounds that such denial may be permissible under existing State laws.

- Authorizes the State to prohibit retail electric sales by an electric utility or its affiliates if the utility or affiliates fail to comply with State requirements of reciprocity.

- Repeals the Public Utility Holding Company Act of 1935 from the date of enactment of proposed legislation.

- Prospectively repeals mandatory power purchase provisions required by the Public Utility Regulatory Policies Act of 1978.

- Recognizes the authority of a State to regulate retail sales and local distribution of electric energy.

S. 1369
Clean Energy Act of 1999
Introduced by Senator James Jeffords (R-VT) on July 14, 1999.

- Directs EPA to promulgate final regulations that establish a schedule of limits on the quantity of each pollutant that all covered generation facilities, (i.e., all non-nuclear facilities with a nameplate capacity of 15 megawatts or greater that use a combustion device to generate power) in the aggregate, shall be permitted to emit in each calendar year beginning in 2002.

- Sets maximum limits for nationwide emissions of carbon dioxide, mercury, nitrogen oxide, and sulfur dioxide for the calendar year 2005 and each year thereafter.

- Requires that EPA perform an annual determination of generation performance standards for carbon dioxide, mercury, nitrogen oxide, and sulfur dioxide emissions per megawatthour of electric production by covered generation facilities.

- Establishes guidelines for earning emission credits for covered generation facilities and prescribes penalties for noncompliance with the emission credit system.

- Prohibits a generating plant from emitting specified pollutants if the EPA determines, upon review, that an emissions rate of specified pollutants in excess of the generation performance standard can be reasonably anticipated to cause or contribute to significant adverse local impacts. Establishes civil penalties for noncompliance.

- Directs the Secretary of Energy to establish a National Electric System Public Benefits Board to fund States for supporting renewable energy sources, universal electric service, energy conservation, and other public purposes. Prescribes funding for the Board by establishing a non-bypassable wires charge of up to 2 mills per kilowatthour.

- Establishes Renewable Energy Portfolio Standards and prescribes minimum requirements for electricity generation from renewable sources to gradually increase from 2.5 percent in 2000 to 20 percent in 2020 (as a share of total electric sales).

- Requires FERC to establish standards and procedures for issuing renewable energy credits to facilities generating electricity from renewable sources.

- Amends PURPA to repeal its mandatory power purchase provisions, but retains the validity of contracts entered under such provisions prior to the enactment of proposed legislation.

- Requires electric companies to allow a retail electric customer to interconnect and employ a net metering system. Sets procedures and guidelines for net metering, and sets safety and performance standards.

- Directs the Secretary of Energy to establish a system of disclosure that enables retail consumers to knowledgeably compare retail electric services offerings, including comparisons based on generation source portfolios, emissions data, and price terms.

S. 1949
Clean Power Plant and Modernization Act of 1999
Introduced by Senator Patrick Leahy (D-VT) on November 17, 1999.

- Sets combustion heat rate efficiency levels for operational and future fossil fuel-fired generating plants, and requires each generating unit to obtain a permit.

- Directs the Department of Energy (DOE) and EPA to promulgate methods of measuring compliance levels. Allows EPA to grant waivers for heat rate efficiency standards.

- Requires all fossil fuel-fired generating units to comply with the air emissions standards put forth in the Clean Air Act not later than 10 years after the date of enactment of proposed legislation. Sets emission rates for certain particulates and requires each generating unit to obtain a permit within the same timeframe. Requires the DOE and EPA to promulgate methods for determining compliance.

- Directs the Administrator of EPA to promulgate fuel sampling and monitoring techniques, reporting requirements, and disposal procedures for certain pollutants.

- Amends the Internal Revenue Code of 1986 by (1) extending Renewable Energy Production Credits, (2) imposing a tax on fossil fuel-fired generating units, (3) reviewing and adjusting tax rates on a biannual basis, and (4) creating a Clean Air Trust Fund.

- Provides grants to publicly owned generating units that make capital expenditures for compliance purposes.

- Grants monies to fund research and development programs focused on generating electric power from renewable resources, clean coal technologies, gas turbine technologies, and combined heat and power technologies.

- Requires DOE, the Federal Energy Regulatory Commission, and the EPA to submit a report to Congress within 2 years of enactment of proposed legislation to evaluate the implementation of proposed legislation.

- Provides dislocation and worker adjustment funds for coal industry workers who are terminated from employment and communities that are adversely affected due to downsizing of the coal industry.

- Appropriates money for the development and implementation of carbon sequestration strategies.

S. 2071
Electric Reliability 2000 Act
Introduced by Senator Slade Gorton (R-WA) on February 10, 2000.

- Provides that FERC shall have jurisdiction over the electric reliability organization, all affiliated regional reliability entities, all system operators, and all bulk power system users.

- Allows any person, including the North American Electric Reliability Council and its member Regional Reliability Councils, to submit to FERC, before designation of an electric reliability organization, any reliability standard, guidance, practice, or amendment to a reliability standard, guidance, or practice that the person proposes to be made mandatory and enforceable.

- Directs FERC to (1) propose regulations specifying procedures and requirements for an entity to apply for designation as the electric reliability organization not later than 90 days after the date of enactment, (2) provide notice and opportunity for comment on the proposed regulations, and (3) promulgate final regulations not later than 180 days after the date of enactment.

- Mandates that the electric reliability organization submit to FERC (1) proposals for any new or modified organization standards, and (2) any proposed change in a procedure, governance, or funding provision relating to delegated functions.

- Requires the electric reliability organization, at the request of an entity, to enter into an agreement with the entity for the delegation of authority to implement and enforce compliance with organization standards in a specified geographic area if the electric reliability organization finds that the entity satisfies certain requirements and the delegation would promote the effective and efficient implementation and administration of bulk power system reliability.

- Requires each system operator to be a member of the electric reliability organization and any affiliated regional reliability entity operating under an agreement applicable to the region in which the system operator operates, or is responsible for the operation of, a transmission facility.

- Allows the electric reliability organization to impose a penalty, limitation on activities, functions, or operations, or other disciplinary action against a bulk-power system user if the electric reliability organization, after notice and an opportunity for interested parties to be heard, issues a finding in writing that the bulk power system user has violated an organization standard.

- Directs the electric reliability organization to conduct periodic assessments of the reliability and adequacy of the interconnected bulk power system and report annually to the Secretary of Energy and the Commission its findings and recommendations for monitoring or improving system reliability and adequacy.

- Prescribes all appropriate steps that the electric reliability organization shall take to gain recognition in Canada and Mexico.

S. 2098
Electric Power Market Competition and Reliability Act
Introduced by Senator Frank Murkowski (R-AK) on February 24, 2000.

Title I: Amendments to the Federal Power Act

- Amends the Federal Power Act to (1) place within the ambit of Federal regulation unbundled interstate transmission of electric energy sold at retail, and (2) place within the jurisdiction of the State within which the energy is consumed the bundled retail sale of electric energy, unbundled local distribution service, and unbundled retail sale of electric energy and attendant facilities.

Title II: Repeal of PURPA Mandatory Purchase Requirement

- Directs that, with respect to new contracts, no electric utility shall be required to enter into a new contract or obligation to purchase or sell electricity or capacity under the Public Utility Regulatory Policies Act of 1978.

- Preserves existing contract rights and remedies under such Act.

Title III: Electric Reliability

- Amends the Federal Power Act to provide for the establishment and enforcement of mandatory reliability standards to ensure the reliable operation of the bulk power system.

- Grants FERC jurisdiction over (1) the Electric Reliability Organization, (2) all affiliated regional reliability entities (entities to which authority has been delegated to enforce compliance with reliability standards), (3) all system operators and all users of the bulk power system for purposes of approving and enforcing compliance with standards in the United States.

- Provides that, before establishment of the Electric Reliability Organization, any person (including the North American Electric Reliability Council and its member Regional Reliability Councils) shall file a proposed reliability standard, guidance, or practice which, subject to FERC approval, shall be mandatory and enforceable.

Title IV: Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 1999

- Repeals the Public Utility Holding Company Act of 1935 effective 1 year after enactment of this title.

- Prescribes procedural guidelines for (1) FERC access to records of a public utility or natural gas holding company, and (2) State access to records of a public utility in a holding company system.

- Instructs FERC to promulgate a final rule to exempt for such Federal access requirements any holding company with respect to one or more (1) qualifying facilities under PURPA, (2) exempt wholesale generators, or (3) foreign utility companies.

- Retains the jurisdiction of FERC and State commissions to determine whether a public utility company or natural gas company may recover in rates any costs of affiliate transactions; grants FERC certain FPA enforcement powers; and transfers from the Securities and Exchange Commission to FERC all books and records that relate primarily to the functions vested in FERC by this Act.

Title V: Nuclear Decommissioning

- Permits a nuclear power facility licensee to petition the Nuclear Regulatory Commission for a determination of whether (1) adequate amounts are deposited in its nuclear decommissioning trust fund, and (2) future funding for any nuclear power plant is assured for any nuclear power plant owned in whole or in part by such licensee.

Appendix D

Electric Power Industry Statistics

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Electric Power Industry Statistics

The Energy Information Administration (EIA) collects and disseminates electric power industry statistics, and a summary of those statistics is provided in Table D1. The following publications contain additional industry data relevant to this report and are available from EIA's website at http://www.eia.doe.gov. The reports are also available in hardcopy by contacting the National Energy Information Center via telephone at 202-586-8800 or via Internet at infoctr@eia.doe.gov. Previous analysis reports dealing with the restructuring of the electric power industry are also attainable.

Carbon Dioxide Emissions from the Generation of Electric Power in the United States
This report summarizes carbon dioxide emissions produced by electricity generation in the United States.

Electric Power Annual, Volume I
This publication contains data on net generation; fossil fuel consumption, stocks, receipts, and cost; generating unit capability; retail sales of electricity and associated revenue; and the average revenue per kilowatthour of electricity sold.

Electric Power Annual, Volume II
This publication presents an overview of the electric power industry in the United States and a summary of industry statistics at national, regional, and State levels.

Electric Power Monthly
This report provides monthly statistics at the State, Census division, and national levels for net generation, fossil fuel consumption and stocks, quantity and quality of fossil fuels, cost of fossil fuels, electricity sales, revenue, and average revenue per kilowatthour of electricity sold.

Electric Sales and Revenue
This publication provides information on electricity sales, associated revenue, average revenue per kilowatt-hour sold, and number of consumers throughout the United States. Data are presented at the national, Census division, State, and electric utility levels.

Electric Trade in the United States
This report presents information on bulk power transactions by investor-owned utilities, Federal and other publicly owned utilities, and cooperative utilities.

Financial Statistics of Major U.S. Investor-Owned Electric Utilities
This publication presents summary and detailed financial accounting data on investor-owned electric utilities.

Financial Statistics of Major U.S. Publicly Owned Electric Utilities
This report presents summary financial data for the past 5 years and detailed current financial data on major publicly owned electric utilities.

Inventory of Electric Utility Power Plants in the United States
This report provides annual statistics on generating units operated by electric utilities in the United States. The publication also presents a 5-year outlook for generating unit additions and retirements.

Inventory of Nonutility Power Plants in the United States
This publication summarizes U.S. nonutility data with detailed information on existing and planned net summer capability, nameplate capacity, energy source and prime mover, as well as information on facility owner and facility locations.

The Restructuring of the Electric Power Industry – A Capsule of Issues and Events
This brochure offers an overview of electric power industry restructuring, including the major changes that have already occurred, their causes, and currents events.

State Electricity Profiles
This report is designed to profile each State and the District of Columbia regarding not only their current restructuring activities but also their electricity generation and concomitant statistics. Included are data

on a number of subject areas, including generating capability, generation, revenues, fuel use, capacity factor of nuclear plants, retail sales, and pollutant emissions.

U.S. Electric Utility Demand-Side Management
This publication presents comprehensive information on electric power industry demand-side management (DSM) activities in the United States at the national, regional, and utility levels.

Table D1. Electric Power Industry Summary Statistics for the United States, 1998

Item	1998
Electric Power Industry[1]	
Generating Capability (megawatts)[2]	775,885
Net Generation (million kilowatthours)	3,617,873
Emissions (thousand short tons)[3]	
Sulfur Dioxide (SO_2)	13,083
Nitrogen Oxides (NO_x)	7,902
Carbon Dioxide (CO_2)[4]	2,455,267
Electric Utilities	
Generating Capability (megawatts)[2,5,9]	686,692
Coal	299,739
Petroleum	62,959
Gas	125,386
Hydroelectric Pumped Storage	18,898
Nuclear	97,070
Waste Heat	4,818
Hydroelectric (conventional)	75,525
Other Renewable	
Geothermal	1,550
Biomass[6]	504
Wind	9
Photovoltaic	5
Net Generation (million kilowatthours)	3,212,171
Coal	1,807,480
Petroleum[7]	110,158
Gas	309,222
Nuclear	673,702
Hydroelectric Pumped Storage[8]	-4,441
Hydroelectric (conventional)	308,844
Other Renewable	
Geothermal	5,176
Biomass[6]	2,024
Wind	3
Photovoltaic	3
Consumption	
Coal (million short tons)	911
Petroleum (million barrels)[10]	179
Gas (billion cubic feet)	3,258
Stocks (Year End)	
Coal (million short tons)	121
Petroleum (million barrels)[11]	54
Receipts	
Coal (million short tons)	929
Petroleum (million barrels)[12]	165
Gas (billion cubic feet)[13]	2,924
Cost (cents per million Btu)[14]	
Coal	125.2
Petroleum[15]	213.6
Gas	238.1
Sales To Ultimate Consumers (million kilowatthours)	3,239,818
Residential	1,127,735
Commercial	968,528
Industrial	1,040,038
Other[16]	103,518
Revenue From Ultimate Consumers (million dollars)	218,346
Residential	93,164
Commercial	71,769
Industrial	46,550
Other[16]	6,863

See footnotes at end of table.

Table D1. Electric Power Industry Summary Statistics for the United States, 1998 (Continued)

Item	1998
Average Revenue per Kilowatthour (cents)	6.74
Residential	8.26
Commercial	7.41
Industrial	4.48
Other[16]	6.63
Net Electric Plant Inc Fuel (million dollars)	
Major Investor Owned	333,006
Major Publicly Owned Generator/Nongenerator	69,725
Emissions (thousand short tons)[17]	
Sulfur Dioxide (SO_2)	12,432
Nitrogen Oxides (NO_X)	7,221
Carbon Dioxide (CO_2)	2,209,286
Noncoincidental Summer Peak Load (megawatts)	669,069
DSM Actual Peak Load Reductions (megawatts)	27,231
DSM Energy Savings (million kilowatthours)	49,167
Nonutility Power Producers	
Installed Capacity (megawatts)	98,085
Coal[18]	13,712
Petroleum Only[19]	2,629
Gas Only[20]	37,530
Petroleum/Natural Gas (combined)	23,105
Nuclear	--
Hydroelectric (conventional)	4,136
Other Renewable	
Geothermal	1,449
Biomass[6]	10,374
Wind	1,689
Solar Thermal	385
Photovoltaic	--
Other[21]	3,075
Gross Generation (million kilowatthours)	421,364
Coal[18]	70,369
Petroleum[19]	17,533
Gas[20]	247,613
Nuclear	--
Hydroelectric (conventional)	14,633
Other Renewable	
Geothermal	9,882
Biomass[6]	53,682
Wind	3,015
Solar Thermal	887
Photovoltaic	--
Other[21]	3,750
Consumption[22]	
Coal (Thousand short tons)	56,850
Petroleum (Thousand barrels)[23]	58,745
Natural Gas (Million cubic feet)	2,666,430
Other Gas (Million cubic feet)[24]	881,017
Supply and Disposition (million kilowatthours)	
Gross Generation	421,364
Receipts[25]	90,675
Deliveries[26]	275,260
Facility Use	236,770
Emissions (thousand short tons)[27]	
Sulfur Dioxide (SO_2)	651
Nitrogen Oxides (NO_X)	681
Carbon Dioxide (CO_2)	245,981

[1] Electric utility and nonutility values (capability versus capacity, net versus gross generation, total emissions versus emissions for the production of electricity) may not be summed directly.

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

[3] In 1997, the useful utility thermal output produced additional emissions of 192 thousand short tons of sulfur dioxide, 66 thousand short tons of nitrogen oxides, and 18,159 thousand short tons of carbon dioxide. In 1998, the useful utility thermal output produced additional emissions of 231 thousand short tons of sulfur dioxide, 91 thousand short tons of nitrogen oxides, and 29,267 thousand short tons of carbon dioxide. In 1997, the useful nonutility thermal output produced additional emissions of 775 thousand short tons of sulfur dioxide, 473 thousand short tons of nitrogen oxides, and 143,824 thousand short tons of carbon dioxide. In 1998, the useful nonutility thermal output produced additional emissions of 756 thousand short tons of sulfur dioxide, 493 thousand short tons of nitrogen oxides, and 185,084 thousand short tons of carbon dioxide.

[4] The report, *Carbon Dioxide Emissions from the Generation of Electric Power in the United States*, presented carbon dioxide emissions of 2,359,853 thousand short tons in 1997 and 2,447,457 thousand short tons in 1998. The nonutility data were revised since the October 15, 1999 release of that report.

Table D1. Electric Power Industry Summary Statistics for the United States, 1998 (Continued)

Item	1998

[5] Net summer capability based on primary energy source. Waste gases and waste steam are included in the original primary energy source (i.e., coal, petroleum, or gas). Historical data have been revised to reflect this change.
[6] Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural byproducts, straw, tires, landfill gases, and fish oils.
[7] Includes petroleum coke.
[8] Represents total pumped storage facility production minus energy used for pumping. Negative generation denotes that electric power consumed for plant use exceeds gross generation.
[9] Includes 216 megawatts multi-fueled capacity and 13 megawatts fueled by hot nitrogen.
[10] Does not include petroleum coke consumption of 1,400 thousand short tons in 1997 and 1,769 thousand short tons in 1998.
[11] Does not include petroleum coke stocks of 469 thousand short tons at year end 1997 and 559 thousand short tons at year end 1998.
[12] Does not include petroleum coke receipts of 2,192 thousand short tons in 1997 and 3,217 thousand short tons in 1998.
[13] Includes small amounts of coke-oven, refinery, blast furnace, and landfill gas.
[14] Average cost of fuel delivered to electric generating plants with a total steam-electric nameplate capacity of 50 or more megawatts; average cost values are weighted by Btu.
[15] Does not include petroleum coke cost of 91.2 cents per million Btu in 1997 and 71.2 cents per million Btu in 1998.
[16] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
[17] Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. As of 1998, emission factors for the calculation of carbon dioxide emissions have been changed. Historical data were revised to reflect that change.
[18] Includes coal, anthracite culm, coke breeze, fine coal, waste coal, bituminous gob, and lignite waste.
[19] Includes petroleum, petroleum coke, diesel, kerosene, liquid butane, liquid propane, oil waste, and tar oil.
[20] Includes natural gas, waste heat, waste gas, butane, methane, propane, and other gas.
[21] Includes hydrogen, sulfur, batteries, chemicals, and purchased steam.
[22] Includes all combustible fuels burned at generating facilities (not just for the production of electricity).
[23] Does not include petroleum coke consumption of 4,364 thousand short tons for 1997 and 4,470 thousand short tons for 1998.
[24] Includes butane, methane, propane, digester gas, and other gas.
[25] Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
[26] Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in these data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-860B and the Form EIA-867 are filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures contribute to the disparity. In addition, since the frame for the Form EIA-860B and the Form EIA-867 is derived from utility surveys, the Form EIA-860B and the Form EIA-867 universes lag 1 year.
[27] In 1998, emission factors for the calculation of carbon dioxide and the reductions from nitrogen oxides and sulfur dioxide have been changed. Historical data were revised to reflect that change.

R = Revised data.

Notes: • Data previously published have been reclassified by energy source and have been changed to reflect these changes. • Data for nonutiliity power producers and emissions are preliminary for 1998; other data in this table are final. • Totals may not equal sum of components because of independent rounding. • Percent change is calculated before rounding.

Sources: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities"; Form EIA-759, "Monthly Power Plant Report"; Form EIA-860, "Annual Electric Generator Report" for 1997; Form EIA-860A, "Annual Electric Generator Report - Utility" for 1998; Form EIA-861, "Annual Electric Utility Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report"; Form EIA-860B, "Annual Electric Generator Report- Nonutility" for 1998 and Form EIA-867, "Annual Nonutility Power Producer Report" for 1997; Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others" as edited by Navigant Consulting, Inc.; FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; Form EIA-411, "Coordinated Bulk Power Supply Programs"; Department of Energy, Office of Emergency Policy, Form OE-411, "Coordinated Bulk Power Supply Program."