DOE/EIA-0562(98)
Distribution Category UC-950

The Changing Structure of the Electric Power Industry: Selected Issues, 1998

July 1998

Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585

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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. Under this program, the EIA 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: Selected Issues, 1998*. This report is one in a series of reports meant to provide a comprehensive analysis of key issues brought forth by the movement of the U.S. electric power industry toward competition.

This publication is intended for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

The legislation that created the EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions.

The EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decisionmakers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

Charles Smith supervised the editing of this report and Rebecca McNerney supervised production with assistance from Terry Varley, Lisa Kinner, and Sandra Smith. Theresa Simonds provided invaluable research assistance.

This report can be accessed from EIA's World Wide Web site at http://www.eia.doe.gov.

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Executive Summary

More than 3,000 electric utilities in the United States provide electricity to sustain the Nation's economic growth and promote the well-being of its inhabitants. At the end of 1996, the net generating capability of the electric power industry stood at more than 776,000 megawatts. Sales to ultimate consumers in 1996 exceeded 3.1 trillion kilowatthours at a total cost of more than $210 billion. In addition, the industry added over 9 million new customers during the period from 1990 through 1996.

The above statistics provide an indication of the size of the electric power industry. Propelled by events of the recent past, the industry is currently in the midst of changing from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation. Advances in power generation technology, perceived inefficiencies in the industry, large variations in regional electricity prices, and the trend to competitive markets in other regulated industries have all contributed to the transition.[1] Industry changes brought on by this movement are ongoing, and the industry will remain in a transitional state for the next few years or more.

During the transition, many issues are being examined, evaluated, and debated. This report focuses on three of them: how wholesale and retail prices have changed since 1990; the power and ability of independent system operators (ISOs) to provide transmission services on a nondiscriminatory basis; and how issues that affect consumer choice, including stranded costs and the determination of retail prices, may be handled either by the U.S. Congress or by State legislatures.

Wholesale and Retail Trade

Of a total of 3,195 electric utilities in the United States, nearly two-thirds have no generating capability. They buy electricity from other utilities to meet the requirements of their customers. As a result, about 55 percent of total domestic consumption of electricity represents sales by other utilities and nonutilities. Wholesale power sales and purchases thus represent market forces in which prices affect both the generation and the retail markets.

An analysis of EIA data on wholesale and retail trade transactions during the period from 1990 through 1996 offers the following insights:

- The market has historically exhibited a willingness to pay a significant premium for assurance of supply. Accordingly, wholesale electricity commands a premium in price when purchases are negotiated on a firm basis. Correspondingly, nonfirm purchases are priced lower.

- Even as trading practices change, it is not certain that the premium for firm supplies will decline. Existing long-term contracts that incorporate premium payments will continue in place, but will expire over a period of time in the future. Accordingly, the premium will continue to exist for the foreseeable future.

- Industrial customers, in the aggregate, have secured price reductions during the 1992-1996 timeframe, paying retail prices that are approximately equal to the wholesale prices for firm power. During this time period, the national average electricity price for the industrial sector declined from 4.8 cents per kilowatthour to 4.6 cents per kilowatthour. In contrast, residential prices increased in most regions from an average of 8.2 cents per kilowatthour to 8.4 cents per kilowatthour.

Independent System Operators (ISOs) and Wholesale Competition

Many electric utilities owning bulk power transmission facilities are collaborating to create regional ISOs to manage and operate the transmission grid in their regions. These new entities will provide nondiscriminatory access to the transmission grid. Although the ISO concept has gained momentum in recent years, utility participation is fragmented, and many unresolved

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

issues remain. The following are highlights of changes and issues related to the creation of ISOs:

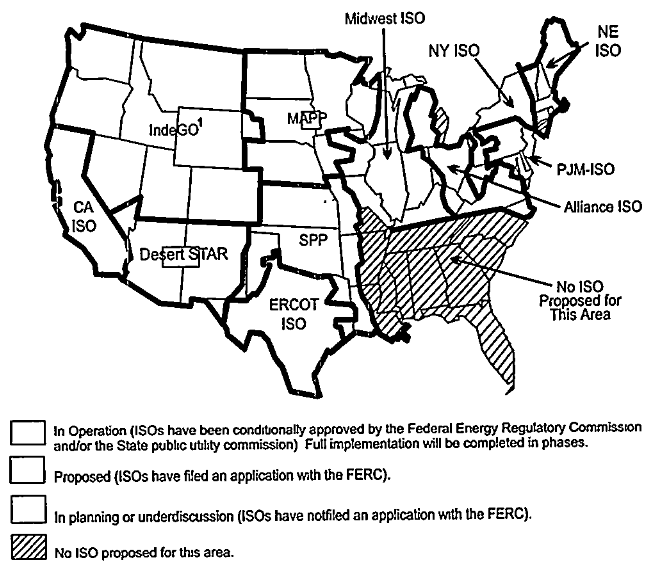
- Four ISOs—California ISO, ISO-New England, the Pennsylvania, New Jersey, Maryland ISO, and the Electric Reliability Council of Texas-Texas ISO—have started operating, and seven others are being planned (Figure ES1).

- Properly designed, ISOs have the potential for improving the operating efficiency of the transmission system by creating a unified regional transmission tariff, and by designing more efficient methods for pricing transmission services using market-oriented approaches.

- Many utilities have not joined an ISO, creating gaps in the ISO coverage of the transmission system. Fragmented coverage negates many of the benefits that an ISO would bring to a regional transmission system.

- Maintaining a reliable and secure regional transmission grid has received wide attention with increased competition. The ISO's responsibility and authority with regard to this issue are under study by industry leaders.

Figure ES1. Independent System Operators in Operation, Proposed, or Under Discussion as of March 31, 1998



[1]As of March 1998, continued development of IndeGO has been postponed, and its future is uncertain.

IndeGO: Independent Grid Operator; MAPP: Mid-Continent Area Power Pool; SPP: Southwest Power Pool; PJM: Pennsylvania, New Jersey, Maryland; ERCOT: Electric Reliability Council of Texas.

Note: ISO control of the transmission grid is incomplete in most of the regions shown on the map. Data are not available to show specific areas covered within regions.

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

Ratesetting and Consumer Choice Issues

A number of States are introducing retail competition in electricity, enabling customers to choose their suppliers. Twelve States have passed legislation establishing retail competition, and the public utility commissions in six other States have issued regulatory orders introducing retail competition (Figure ES2).

Stranded Cost Issues

In the new competitive environment, some utilities will have stranded costs as a result of the proposed transition to competition at the retail level.[2] Estimates of these stranded costs range from $100 billion to $200 billion nationwide. Many States have already opted to provide an opportunity for full recovery of stranded costs contingent on adoption of appropriate mitigation strategies that include divestiture and/or securitization.[3] In the process, they have invariably succeeded in securing rate reductions for customers in exchange for providing their utilities with the opportunity to recover stranded costs.

States that have negotiated a workable consensual arrangement with the stakeholders appear to have a reasonable chance of success in implementing competition at the retail level. Denying an opportunity for full recovery has resulted in slowing the transition to competition, as in the case of New Hampshire.

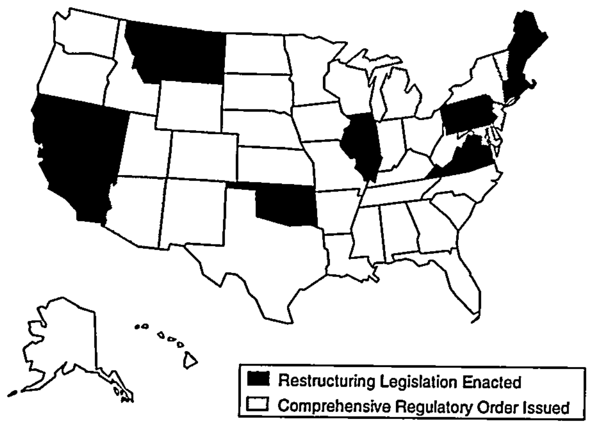
Performance-Based Ratemaking

Pending full implementation of competition, some States have adopted performance-based ratemaking (PBR) as an alternative to traditional ratemaking. Under the

[2] Recovery of stranded costs relative to wholesale transactions has already been addressed by the Federal Energy Regulatory Commission in its Orders 888 and 888-A.

[3] Securitization is a financing tool employed to reduce the cost of business credit. It refers to the creation of a financial security backed by a revenue stream exclusively used to pay debt associated with that security. Additional details on the subject are provided in Chapter 4 of this report.

Figure ES2. States Which Have Issued Comprehensive Deregulation Orders and/or Enacted Restructuring Legislation as of June 1, 1998



Notes: **States with Legislation:** California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia. **States with Orders:** Arizona, Maryland, Michigan, New Jersey, New York, and Vermont. Note that California, Massachusetts, and New Hampshire each have regulatory orders and legislation in place.

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

traditional cost-of-service-based approach, utilities have little or no incentive to reduce costs. The primary aim of PBR is to encourage efficiency improvements (or productivity enhancements) by offering financial incentives to utilities to lower costs and, ultimately, rates. Incentives usually take the form of caps either on prices or on revenues. Another variant—the sliding scale—keeps the rate of return within a certain band, with adjustments for earnings outside the band.

To the extent that PBR plans lead to a decline in rates, their implementation may be preferable to the traditional regulatory approach. This possibility rests on the capability of PBR plans to respond more effectively to external changes than may be feasible under traditional regulatory schemes. The danger is that focusing exclusively on cost reduction may cause other quality-of-service issues to be overlooked. Inadequacies in monitoring and evaluation could also lead to unintended results. PBR plans surveyed in this report are all relatively recent. As such, their effectiveness in reducing costs has yet to be determined.

Pilot Programs

On their own initiative, or by legislative or regulatory orders, utilities in 10 States have started retail pilot programs to test the feasibility of retail competition. These pilot programs allow participating customers to purchase electricity from alternative suppliers, while taking delivery using the incumbent utility's facilities.

Experience so far indicates that industrial customers show more interest in participating in the pilot programs than do commercial or residential customers. The low rate of participation by the latter groups is caused by a number of factors: insufficient cost savings, ineffective recruitment of participants, or burdensome participation procedures. Although problems exist, both regulators and the utilities have obtained valuable experience and feedback from pilot programs, which will help them implement full retail competition.

It is possible that additional issues will emerge as universal retail access gains momentum in the States and the overall demand for power continues to grow, eliminating the capacity excess that currently prevails systemwide. The success of fully competitive markets depends on the ability of the system to add capacity as needed and without undue constraints. Opening generation to competitive forces while concurrently retaining the current siting and licensing powers for new power plants and transmission lines may possibly limit the benefits that competition can bestow. Under these conditions, it is possible for current facility owners to seek and recover prices higher than those prevailing under fully competitive conditions.

State and Federal Initiatives

Legislation introduced in the 105th Congress covers diverse spheres of restructuring activity. Some bills are comprehensive—expanding on initiatives in the Energy Policy Act of 1992 and building on Federal Energy Regulatory Commission actions—to facilitate retail competition by a date certain. Others focus on a variety of selected issues. The Administration released its *Comprehensive Electricity Competition Plan* in March 1998. Consensus-building efforts among stakeholders still seem to be ongoing while an agreement is sought.

States generally do not consider Federal legislation as a requirement for promoting retail competition. They concede, however, that a carefully defined Federal framework would be useful in advancing the economic and social benefits of competitive markets. Some States support Federal legislation in areas where jurisdictional conflicts may be a possibility, or where such legislation would mitigate or eliminate impediments to competition.

1. Introduction

Restructuring of the electric power industry in the United States is continuing, with electricity generation markets being opened to competition. The initial impetus nudging the industry toward competition stemmed from the unanticipated operational impacts of the Public Utility Regulatory Policies Act of 1978 (PURPA), which encouraged the supply of wholesale power to electric utilities from nontraditional sources (i.e., renewable energy sources).[1] While the inroads made by nonutility power generators into the generation monopoly were a positive force, the impact on utilities and prices made the provision a mixed blessing.[2] The electricity-related provisions of the Energy Policy Act of 1992 (EPACT) then became the catalyst for accelerating the pace of competition in electricity trade at the wholesale level.[3]

More specifically, the EPACT provisions amended the Public Utility Holding Company Act of 1935, the Federal Power Act of 1935, and the PURPA provisions in the areas that govern, among other things, the future of nonutility power generation and the associated wholesale power transactions. Of the several EPACT provisions that affect electric utilities, the two designed to further industry competition are: (1) creating a new class of exempt wholesale generators (EWGs) and (2) expanding the authority of the Federal Energy Regulatory Commission (FERC) to order open transmission access under Section 211 of the Federal Power Act (see box on page 2 and Appendix A). The responsibility to determine the EWG status and to ensure the availability of transmission facilities in a nondiscriminatory manner was entrusted to the FERC.

Based on the above legislative mandate and with an intent to introduce wholesale competition in electricity, the FERC initiated appropriate rulemaking procedures.[4] Its two landmark rulings, Order No. 888 and Order No. 889, issued in April 1996, require all public utilities that own, control, or operate transmission facilities to file nondiscriminatory open-access tariffs that would be applied to all parties contracting for transmission service.[5] Since these Orders were issued, activity to open electricity markets to competition has increased significantly at the State and Federal levels.

[1] PURPA's primary objective was to encourage improvements in energy efficiency through the expanded use of cogeneration and by creating a market for electricity produced from unconventional sources like renewables and waste fuels. While preserving the industry's vertically integrated structure, PURPA aimed at a modest modification by adding the obligation to look to nontraditional suppliers in conjunction with utilities' existing and proposed generating capabilities. No changes, therefore, were postulated to the cost-based pricing of electricity regulation. Yet, by encouraging nonutility power generation and by making such output easily marketable on a wholesale basis, PURPA's provisions introduced several, far-reaching operational and regulatory changes in the electric utility industry. In the evolving wholesale market for electric power, PURPA's most notable contribution was to introduce competition while taking future supply options into account. For a further discussion of this subject, see Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996).

[2] The investor-owned utilities complained that PURPA regulations forced them to purchase power even when the need for capacity did not exist. The long-term obligations imposed by such purchases tended to adversely affect the credit ratings of some of the investor-owned utilities. For a complete discussion of this topic, see Energy Information Administration, *Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities*, DOE/EIA-0580 (Washington, DC, June 1994).

[3] Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996).

[4] In fact, FERC issued policy statements in critical areas and initiated a number of proceedings in the period immediately following the passage of EPACT in 1992. These include: (1) Regional Transmission Group Policy Statement, Docket No. RM93-3-000 (July 30, 1993), (2) Docket No. RM94-7-000, *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Notice of Proposed Rulemaking (June 29, 1994), (3) Transmission Pricing Policy Statement, Docket No. RM93-19-000 (October 26, 1994), (4) Pooling Notice of Inquiry, Docket No. RM94-20-000 (October 26, 1994), (5) Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking: (I) *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, Docket No. RM95-8-000, and (ii) *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Docket No. RM-94-7-001 (March 29, 1995), and *Notice of Inquiry on Merger Policy*, Docket No. RM-96-000 (January 31, 1996).

[5] For additional details on these Orders, see Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 51-75.

Significant EPACT Provisions Affecting Electric Utilities[a]

Amendments to the Public Utility Regulatory Policies Act (PURPA) of 1978:

Mandates that State utility regulatory entities evaluate new efficiency standards designed to encourage investments in conservation and energy efficiency by electric utilities. Included in the standards are:

- Implementation of integrated resource planning procedures that compare electricity supply and demand-side management options on a systematic basis.
- Provision of cost recovery for investments in energy conservation, energy efficiency, and other demand-side management activities and measures.
- Creation of incentives for investments in cost-effective improvements in efficiency of power generation and supply.
- Four new rulemaking standards regarding the purchase of wholesale power.

Amendments to the Public Utility Holding Companies Act (PUHCA) of 1935:

- Fosters competition in wholesale electricity markets by creating a new category of power suppliers to be called *Exempt Wholesale Generators* or *EWGs*, largely exempt from all the restrictive provisions of PUHCA. Determination of an *EWG* status is assigned to the Federal Energy Regulatory Commission (FERC).
- Provides protection to consumers against financial abuses between regulated and unregulated entities, including cross-subsidization.
- Authorizes U.S. electric utilities and EWGs to participate or invest in foreign utilities, under certain circumstances.

Amendments to the Federal Power Act (FPA) of 1935:

- Greatly broadens the definition of circumstances under which FERC shall order transmission-owning utilities to wheel power.
- Ensures that just and reasonable costs incurred in providing the above service be recovered.
- Precludes issuance of any order inconsistent with State laws governing the retail marketing areas of electric utilities.

[a]Based on Title I, Subtitle B, "Utilities," and Title VII, "Electricity," of the Energy Policy Act of 1992.

The purpose of this report is to provide an analytical assessment of the changes taking place as the electric power industry moves along the road to competition. In view, however, of the magnitude and the multi-dimensional character of restructuring issues, this report covers only selected topics from three separate but interrelated issues: market structure, consumer choice, and ratesetting and transition costs. In addition, Federal and State initiatives in promoting competition are presented.

This report also satisfies requirements of the International Atomic Energy Agency (IAEA) in Vienna, Austria, concerning industry restructuring developments in the United States. The IAEA has been working since the early 1990s to provide enhanced modeling capabilities for comparative assessment of different electricity generation options to aid planning and decisionmaking in developing countries. Under the aegis of what has come to be known as the DECADES project, the IAEA is supplementing its earlier efforts by developing a sustainable energy and environmentally acceptable power development program as a part of its assessment process. Within this framework, the evolving U.S. experience is viewed as a valuable case study in lessons learned for application elsewhere.

Chapter 2 presents an overview of the existing patterns of electricity trade and average prices at the wholesale and retail levels. The electric utility industry has moved from a highly restricted but competitive wholesale market for traditional participants (primarily inter-regional trade between utilities or between utilities and independent power producers) to one that is now characterized by increased interregional trade, and to new generating and trading participants. One of the expectations for the future is that end users of electricity will be allowed to participate in a unified wholesale/retail market. Estimates of the existing customer classes help quantify the size of forthcoming markets that may be opened to retail customer choice. Analysis of time series data highlights existing patterns and also provides an insight into potential developments in the future.

Chapter 3 analyzes the emergence and the expected benefits and limitations of the regional independent system operator (ISO), a relatively new entity in the electric power industry. In Order 888, the FERC encouraged regions to create ISOs to eliminate discriminatory practices in bulk power transmission. The ISO concept has progressed far beyond that initial role, however, and now some ISOs are expected to play a significant role in promoting and encouraging wholesale competition. The chapter includes discussions of the status of each ISO proposal and the responsibilities being considered for the proposed ISO. A detailed discussion is presented on the importance of the ISO's governing structure, the role of the regional transmission tariff, the ISO's relationship to system reliability, its relationship to the Open Access Same-Time Information System (OASIS), and its role in monitoring market power.

Chapter 4 deals with ratesetting and customer choice issues. Promoting retail competition hinges on the pace of initiatives from the State regulatory authorities and the extent to which industry claims regarding stranded assets can be accommodated. Progress made in various States is summarized, with a focus on the critical information leading to the penetration of competition in the retail areas. The discussion focuses on the treatment of stranded costs, including recovery mechanisms, performance-based rates, and experiments with pilot programs.

Finally, Chapter 5 looks at issues still being discussed at the Federal and State levels. Summary developments at the Federal and State levels are provided, together with a discussion of potential problems confronting the enactment of legislation to promote industry competition.

2. An Overview of Electricity Trade

Background

The electric utility industry is in the midst of a historical transformation process. Its traditional composition includes investor-owned, publicly owned, cooperative, and Federal entities (Table 1 and Figure 1). The passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPACT) allowed new entities to acquire generation facilities and to provide electrical energy for sale to electric utilities.[6]

The above enactments paved the way for the industry's transformation by effectively eliminating barriers previously existing in the domain of power generation. Opening electricity generation to competitive market forces represents the core for the transformation and restructuring activity that has been implemented. In the process, new entrants, generating and selling power, have made inroads in an industry previously closed to outside participants. Because of this array of changes, the industry is now more commonly called the *electric power industry* rather than the erstwhile *electric utility industry*. Opening the transmission system for competitive market access is now ongoing and represents the next aspect of restructuring the industry.

Actions initiated during the recent past by the Federal Energy Regulatory Commission (FERC) contributed in no small measure to the change in industry nomenclature.[7] FERC modified its regulatory requirements to permit business entities to file for rate tariffs in order to buy and sell electricity at wholesale among all electric utilities.[8] These new entities are called *power marketers*—members do not own or operate generation, transmission, or distribution facilities, but are considered electric utilities. Thus, the combined entry of new power generators and marketers constitutes a change that not only establishes milestones but also propels the industry on its path to competition.

This chapter provides background information and data on various components of electricity trade, their interactions in the market, and their growth and changing roles. Relevant data on retail and wholesale trade in conjunction with data on generating capacity and the transmission network are analyzed. Emerging trends in trade patterns during the period from 1990 through 1996 are presented.

The Supply Side: Generation and Transmission

Generation Resources

U.S. generating capability consisting of utility and nonutility facilities totaled 776,199 megawatts at the end of 1996 (Table 2).[9] Of this, utility capability represents slightly over 90 percent of the total. Utility capability

[6] The enactment of PURPA, among other objectives, aimed to accelerate commercial use of decentralized, small-scale power production (including from renewable resources), cogeneration, and energy conservation. PURPA guaranteed a market for qualified decentralized facilities at an economic price based on a utility's full avoided cost (the utility's marginal cost). Initial rulemaking and the designation of qualifying facilities (QFs) were entrusted to the FERC. In addition to the QFs (which include small power producers and cogenerators), nonutility generators (NUGs) also include independent power producers (IPPs), which are generators (not defined under PURPA) providing capacity and wholesale power to utilities under long-term power sales agreements. By modifying the Public Utility Holding Company Act of 1935 (PUHCA), the EPACT created a new class of IPPs called "exempt wholesale generators" (EWGs), exempt from the corporate and geographic limitations imposed by PUHCA. In concert with other EPACT provisions pertaining to electricity, these actions fostered competition in the electric power industry.

[7] FERC played a critical role in promoting competition in wholesale power even before the enactment of EPACT in 1992. See Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 51-52.

[8] On May 19, 1986, the FERC approved the rate tariff for Citizens Energy Corp (EL86-2-000), which thus became the first power marketer. Only 3 more authorizations were granted before 1990. As 1993 ended, Enron Power Marketing was authorized under ER94-24-000, and that approval raised the total to 11 power marketers. At the end of 1996, EIA identified 80 active power marketers, and more than 200 had approved tariffs on file with the FERC.

[9] This table contains the capability of only those facilities connected to the transmission system. It excludes industrial and other forms of self-generation.

Table 1. Major Characteristics of Electric Utilities by Type of Ownership

Ownership	Major Characteristics
Investor-Owned Utilities (IOUs) IOUs account for about three-quarters of all utility generation and capacity. There are 243 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 10 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 DOE (Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration) • The Alaska Power Administration is in the process of being privatized under Public Law 104-58 enacted on November 28, 1995 • 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 2,010 in the United States.	• Are non-profit 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
Cooperatively Owned Utilities There are 932 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 cooperatives to provide electric service to small rural communities (usually fewer than 1,500 consumers) and farms where it was relatively expensive to provide service

Table 1. **Major Characteristics of Nonutilities by Type of Ownership (Continued)**

Type	Major Characteristics
Cogenerators (QF)	• 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 (Non-QF)	• Creation authorized by EPACT • Are exempt from PUHCA's corporate and geographic restrictions • Are wholesale producers; do not sell at 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 PURPA • Are nonutilities, utilizing a cogenerating technology, and may themselves consume part of the electricity they cogenerate
Independent Power Producers (IPP)	• Generate and sell electric power at wholesale • Usually authorized to sell at market-based rate

QF = Qualifying facility under PURPA (see footnote 6 on page 5).

(which is a mix of fossil and nonfossil fuel sources) is used to generate more than 90 percent of the Nation's electricity sold to end-use customers. Of this, the investor-owned utilities account for nearly 75 percent of the total sales (Figure 2). They also purchase nearly all the power sold by nonutilities (Figure 3). Each of the other three classes of utilities has less than a 10-percent share of generation, accounting for the remaining 25 percent of sales. Their purchases from nonutilities are about 2 percent in the aggregate. However, the mix of renewable and fuel-burning capacity varies among classes of utilities.[10] These characteristics indicate the relative dominance of the investor-owned utilities in the makeup of the electric power generation sector.

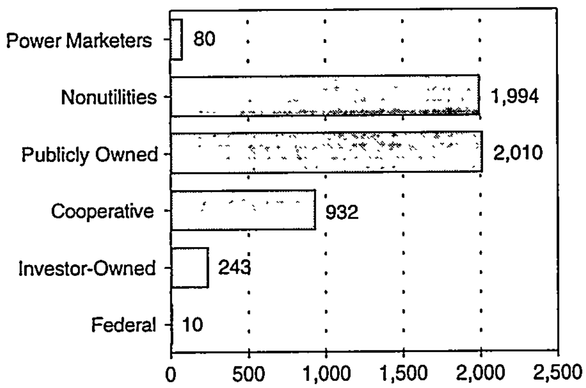
Transmission Network Resources

The U.S. electric transmission system represents a unified electrical network with most of Canada and part of Mexico. The major networks consist of extra-high-voltage connections that serve as the backbone of electrical operations. These integrated power lines have been designed for system support and to permit the transfer of electrical energy from one part of the network to other segments.

Power transfers are, however, not completely free-flowing. Various factors set limits on the extent of the operations. These include restrictions based on lack of contractual arrangements, absence of approved tariffs, reliability considerations (protection of the adequacy of supply and security of operations), and inadequate transmission capability that limits electrical operations. Of the five power grids (electrical networks), the three that serve the United States are (Figure 4): (1) the Eastern Interconnected System, consisting of the eastern two-thirds of the United States and the Canadian Provinces of Saskatchewan, Manitoba, Ontario, New

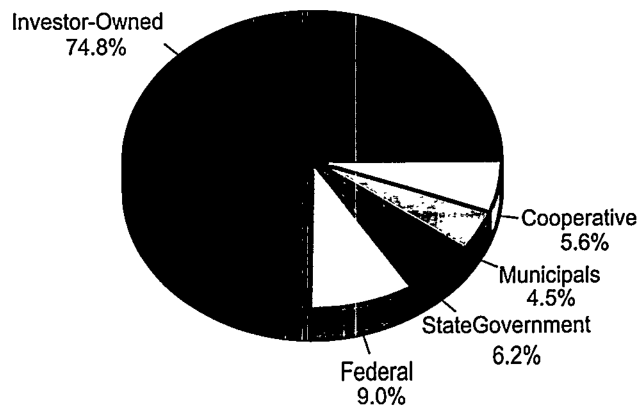
[10] Energy Information Administration, Form EIA-860, "Electric Utility Generator Report."

Figure 1. Composition of the Electric Power Industry in the United States, 1996



Source: Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997).

Figure 2. Net Generation by Different Classes of Utilities, Average of Selected Years, 1990-1996



Note: Averages calculated from 1990, 1992, 1994, and 1996 data.

Source: Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997).

Brunswick, and Nova Scotia; (2) the Western Interconnected System, consisting of the 12 States west of the Rocky Mountains, the western tip of Texas, the Canadian Provinces of Alberta and British Columbia, and the northern portion of the Mexican State of Baja California Norte; and (3) the Texas Interconnected System. Both the Western and Texas Interconnects 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 by these major power grids. The exceptions are in Alaska and Hawaii.

Table 2. Composition of Generating Capability and Generation in the Electric Power Industry, 1996
(Megawatts and Megawatthours)

	Generating Capability		Net Generation	Gross Generation
	Utility-Net	Nonutility-Gross	Utility	Nonutility
Coal	302,421	12,122	1,737,453	61,424
Petroleum	70,421	3,185	67,346	14,951
Natural Gas	140,002	31,024	262,730	213,359
Petroleum/Natural Gas	-	10,875	-	-
Nuclear	101,121	-	674,729	-
Hydroelectric	73,129	3,419	331,058	16,555
Geothermal	1,622	1,346	5,234	10,198
Biomass	442	8,494	1,967	57,997
Wind	8	1,670	10	3,400
Solar Thermal	-	354	-	903
Photovoltaic	4	-	3	-
Pumped Storage	21,110	-	(3,088)	-
Other	-	694	-	3,744
Total	710,279	73,183	3,077,442	382,530

Source: Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997), pp. 13-14.

Figure 3. Nonutility Generation Purchased by the Utility Sector, Average of Selected Years, 1990-1996

Note: Averages calculated from 1990, 1992, 1994, and 1996 data.

Source: Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997).

Transmission Network Operating Characteristics

Interconnected utilities within each power grid operate under coordinated operational and system planning guidelines. The industry-sponsored North American Electric Reliability Council (NERC) and its 10 regional reliability councils are responsible for the establishment of standards, policies, and guidelines for coordination of the bulk power supply. These criteria establish the requirements for adequacy of supply and security (reliability) of the electrical system or, from another perspective, the adequacy of all integrated transmission services operated above distribution-level support needed for customer load. These councils must regularly exchange operating and planning information among regions and the utilities that maintain control of electrical dispatch and have system operational responsibility.

The boundaries of the NERC regions follow the service areas of the electric utilities in the regions. Neither the NERC regions nor most service areas for electric utilities follow State or even national boundaries. Instead, the boundaries are defined by what should be described as electrical geographics of different control operations. As a result, data for interconnected system flows are not available by State. When these data are shown, they are represented by NERC regions.

The Demand Side: Residential, Commercial, and Industrial Users

The domestic power market has two distinct segments—the markets for wholesale power and for retail power. The wholesale market covers the actual purchase and sale of electricity to resellers (who sell to retail customers), in-kind exchanges of electricity, and transmission services along with ancillary services needed to maintain reliability and power quality at the transmission level.[11] Wholesale electricity trade is discussed in the next section of this chapter. The retail energy market may be viewed as a market in which electricity and other energy services are sold directly to all end-use customer classes (i.e., residential, commercial, industrial, and other).[12]

In accordance with the provisions of the Federal Power Act, oversight for regulating the wholesale electric market rests with the FERC. State public utility commissions have the primary jurisdictional responsibility for retail sales to customers served by investor-owned utilities. Oversight of the sales of other utility segments is far from uniform.[13]

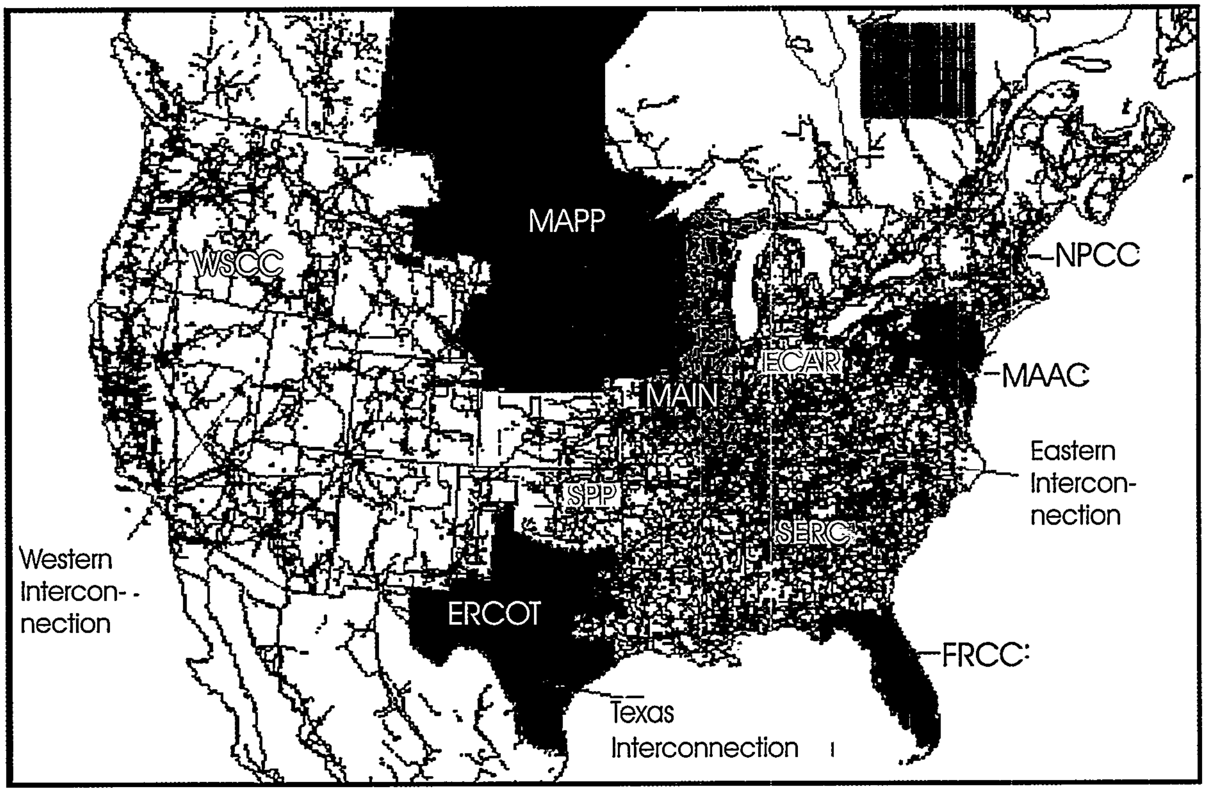
Retail customers use electricity at different consumption levels and have other differentiating characteristics (similar demand patterns or load usage, distribution voltage level, groupings by social and economic considerations). These characteristics are used to differentiate and group them into residential, commercial, industrial, and "other" customer classes.

[11] Ancillary services are those services necessary to support the transmission of energy from generation resources to loads while maintaining reliable operation of the transmission provider's transmission system in accordance with "good utility practice." In Order 888, FERC identified six major ancillary service groupings.

[12] The "other" category includes public street lighting and highway lighting, railroads and railways, government use under special contracts, and other utility department usage as defined by the pertinent regulatory agency and/or electric utility.

[13] Federal electric utilities, for example, are parts of several agencies within the U.S. Government. Their generation is sold primarily to municipal and cooperative electric utilities. Since most of their power is sold on a nonprofit basis, the prices they charge are designed to recoup costs incurred. Approximately 20 States regulate cooperatives, and 7 States regulate municipal utilities; many States defer to local municipal officials or cooperative members. See Energy Information Administration, *Electric Sales and Revenue 1996*, DOE/EIA-0450(96) (Washington, DC, December 1996).

Figure 4. North American Electric Grids, North American Electric Reliability Council (NERC) Regions, and Transmission Lines



NERC Regional Councils

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, Inc.
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

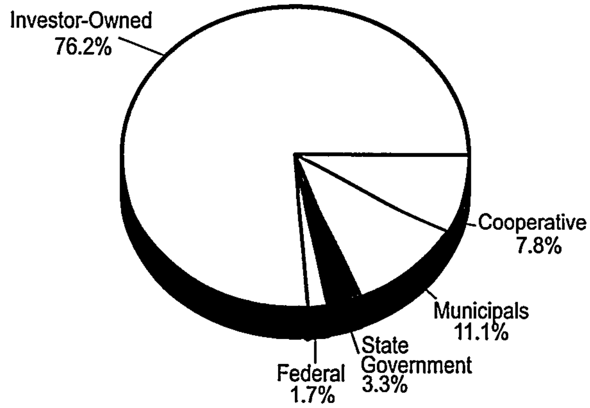
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Classifying customers, as indicated above, is a regulatory procedure that allows for multiple oversight applications. Allocating the cost of service to each customer class and estimating future growth in demand are two critical functions that hinge on using this classification as the starting point. As different suppliers begin competing for customers in open retail markets, the prevailing classification (residential, commercial, industrial, other) may be revised.

Under the prevailing system of assigning billing tariffs to customer classes, all customers pay for electric energy delivered to them under a bundled fee that includes the cost of energy, transmission, distribution, and other charges (taxes, environmental surcharges, fuel adjustment costs, and others).[14] As markets in States open to competition, this billing practice will be subjected to radical changes requiring that all charges be shown separately, or "unbundled."

Investor-owned utilities dominate sales to ultimate consumers. For the period 1990 through 1996, they accounted for 76 percent of the total sales to ultimate consumers, compared with 11 and 8 percent for municipal and cooperative utilities, respectively. Utilities owned or sponsored by State governments and Federal utilities accounted for the remaining 5 percent (Figure 5).

Figure 5. Sales to Ultimate Consumers by Class of Utility, Average of Selected Years, 1990-1996



Note: Averages calculated from 1990, 1992, 1994, and 1996 data.

Source: Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997).

The Customer Base

Retail sales volumes and customer base levels have continued to grow during the 1990-1996 period. The electric power industry has gained more than 9 million new customers since 1990. Of these, new residential customers (approximately 8 million) account for 88.3 percent of the growth. New commercial customers account for nearly 11.6 percent (or over a million customers). The balance is distributed among the industrial and other categories (Table 3).

Sectoral Consumption and Prices

Total retail sales of electricity to ultimate end-use consumers stood at 3.1 trillion kilowatthours in 1996, reflecting an annual average growth of 2.2 percent since 1990 (Table 4). Residential customers accounted for about 34.9 percent of total electricity consumed in 1996, up from 34.1 percent in 1990. The commercial and industrial sectors accounted for 28.6 and 33.3 percent of total consumption during 1996, with the corresponding shares for 1990 being 27.7 and 34.9 percent, respectively (Table 5). These data indicate that consumption in the residential and commercial sectors increased by about 2.7 percent per year during the 1990-1996 period, while industrial consumption increased by an average of 1.4 percent per year during the same period. These differing growth rates partially explain the decline in the industrial sector share of total sales (about 4.6 percent from 1990 to 1996) (Table 5).

Table 3. Number of Retail Customers by Sector in the United States, 1990-1996

Year	Residential	Commercial	Industrial	Other	Total
1990	97,094,514	12,081,942	525,486	858,800	110,560,742
1991	98,295,518	12,178,694	518,272	887,499	111,879,983
1992	99,512,726	12,367,205	547,990	857,614	113,285,537
1993	100,860,071	12,526,377	553,231	795,298	114,734,977
1994	102,320,846	12,733,153	583,935	850,770	116,488,704
1995	103,917,312	12,949,365	580,626	882,422	118,329,725
1996	105,341,408	13,180,632	586,169	893,884	120,002,093

Source: Energy Information Administration, *Electric Sales and Revenue 1996*, DOE/EIA-0540(96) (Washington, DC, December 1997), Table 5, previous issues.

[14] This is an oversimplification of the actual process of paying for producing and delivering electricity to an end-use customer. There are many technical aspects involved in the process that are being assumed away. With the opening of electricity markets to competition, customers will find that their future bills contain line items for various services that are charged separately. The line items may also vary among and within customer classes.

Table 4. Retail Sales, Revenue, and Average Price Paid by End-Use Sector, 1990-1996

Year	Residential	Commercial	Industrial	Other	Total
	Retail Sales in Million Kilowatthours				
1990	924,019	751,027	945,522	91,988	2,712,555
1991	955,417	765,664	946,583	94,339	2,762,003
1992	935,939	761,271	972,714	93,442	2,763,365
1993	994,781	794,573	977,164	94,944	2,861,462
1994	1,008,482	820,269	1,007,981	97,830	2,934,563
1995	1,042,501	862,685	1,012,693	95,407	3,013,287
1996	1,082,491	887,425	1,030,356	97,539	3,097,810
	Revenue in Million Dollars				
	Residential	Commercial	Industrial	Other	Total
1990	72,378	55,117	44,857	5,891	178,243
1991	76,828	57,655	45,737	6,138	186,359
1992	76,848	58,343	46,993	6,296	188,480
1993	82,814	61,521	47,357	6,528	198,220
1994	84,552	63,396	48,069	6,689	202,706
1995	87,610	66,365	47,175	6,567	207,717
1996	90,501	67,827	47,385	6,741	212,455
	Average Revenue per Kilowatthour in Cents				
	Residential	Commercial	Industrial	Other	Total
1990	7.8	7.3	4.7	6.4	6.6
1991	8.0	7.5	4.8	6.5	6.7
1992	8.2	7.7	4.8	6.7	6.8
1993	8.3	7.7	4.9	6.9	6.9
1994	8.4	7.7	4.8	6.8	6.9
1995	8.4	7.7	4.7	6.9	6.9
1996	8.4	7.6	4.6	6.9	6.9

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

Changes in consumption shares have led to changes in the relative contributions of the sectors to revenues in the aggregate. The data indicate that revenue from the residential and the commercial sectors increased annually by about 3.8 and 3.5 percent, respectively, in tandem with the increases in consumption for these sectors. Both sectors increased their share of total revenues coming from all end-use customers, whereas the industrial sector share declined by nearly 11.4 percent, in comparison with a 4.6-percent decline in the share of sales.

An examination of regional prices by sector (Appendix B) indicates that industrial electricity prices (within the contiguous United States) declined in all regions after the enactment of EPACT in 1992.[15] The national average electricity price for the industrial sector declined from 4.8 cents per kilowatthour to 4.6 cents per kilowatthour from 1992 to 1996. In contrast, residential prices increased in most regions from an average of 8.2 cents per kilowatthour to 8.4 cents per kilowatthour during the same period. Prices in the commercial sector also declined in most regions, with the exception of increases in the New England and Mid-Atlantic regions; the national average (for commercial sector prices) declined from 7.7 cents to 7.6 cents per kilowatthour. These sectoral price trends, with the industrial sector securing relatively lower prices in comparison with the residential and commercial sectors, are also confirmed by an examination of average prices (revenues) contributed by various utility groups (Table 5).

It is possible that industrial end users have been able to secure price concessions from their incumbent utilities in

[15] Public discussion in regard to bringing the electric utility industry into a competitive framework preceded the passage of EPACT. Afterwards, attention shifted to retail issues.

Table 5. End-Use Sector Shares and Annual Growth Rates, 1990-1996
(Percent)

Year	Residential	Commercial	Industrial	Other	Total
	Sectoral Share				
Sales					
1990	34.1	27.7	34.9	3.4	100.0
1991	34.6	27.7	34.3	3.4	100.0
1992	33.9	27.5	35.2	3.4	100.0
1993	34.8	27.8	34.1	3.3	100.0
1994	34.4	28.0	34.3	3.3	100.0
1995	34.6	28.6	33.6	3.2	100.0
1996	34.9	28.6	33.3	3.1	100.0
Revenue					
1990	40.6	30.9	25.2	3.3	100.0
1991	41.2	30.9	24.5	3.3	100.0
1992	40.8	31.0	24.9	3.3	100.0
1993	41.8	31.0	23.9	3.3	100.0
1994	41.7	31.3	23.7	3.3	100.0
1995	42.2	31.9	22.7	3.2	100.0
1996	42.6	31.9	22.3	3.2	100.0
	Annual Growth Rates				
	Residential	Commercial	Industrial	Other	Total
Sales	2.7	2.8	1.4	1.0	2.2
Revenue	3.8	3.5	0.9	2.3	3.0
Price	1.2	0.7	(0.4)	1.3	0.7
Cumulative Percentage Change in Share					
Sales	2.6	3.5	(4.6)	8.0	--
Revenue	4.9	3.2	(11.4)	3.9	--
Price	7.7	4.1	(2.1)	7.8	--

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

anticipation of lower rates becoming available with the advent of competition in generation. Industrial customers, as a rule, are well organized, consume more (on average), and are capable of securing concessions from utilities that smaller customers usually find hard to obtain.

State public utility commissions have an abiding interest in maintaining the State's economic viability and often concur with special discounts awarded to industrial users in the hope of retaining them within State boundaries. Incumbent utilities are also likely to offer discounts in attempts to retain market shares in their franchise area and discourage forays by outside service providers. Alternatively, there may have been efforts to realign all rate schedules with the costs of supplying power to each customer group and eliminate any existing cross-subsidization in rates.

Sectoral Prices by Different Classes of Utilities

When utility service is grouped by end-use sectors, traditional differences associated with utility ownership are evident (Table 6). As an example, the cost of debt differs for investor-owned and publicly owned utilities, due to different tax treatment. Dividend payments are required for investor-owned utilities, and repayment of public debt and bonds is an obligation for Federal and public utilities. Not all Federal utilities have retail customers (or they have very few if they are power

Table 6. Average Retail Electricity Prices by End-Use Sector, 1990-1996
(Cents per Kilowatthour)

Year	Residential				Commercial			
	IOU	Publicly	Coop.	Federal	IOU	Publicly	Coop.	Federal
1990	8.2	6.4	7.4	5.7	7.5	6.5	7.1	5.9
1991	8.5	6.4	7.5	6.0	7.7	6.5	7.3	7.1
1992	8.6	6.6	7.7	5.8	7.8	6.6	7.4	6.1
1993	8.8	6.6	7.7	5.8	7.9	6.8	7.4	6.2
1994	8.8	6.7	7.8	6.4	7.9	6.7	7.4	6.0
1995	8.9	6.7	7.7	6.6	7.9	6.7	7.3	7.0
1996	8.9	6.7	7.5	6.5	7.8	6.6	7.2	7.0
	Industrial				Other			
	IOU	Publicly	Coop.	Federal	IOU	Publicly	Coop.	Federal
1990	4.8	4.7	4.7	3.3	7.0	6.5	6.4	1.7
1991	5.0	4.8	4.7	2.9	7.1	6.2	6.4	1.9
1992	5.0	4.8	4.7	2.7	7.2	6.8	6.6	2.0
1993	5.0	4.9	4.6	2.9	7.3	7.1	7.0	1.9
1994	4.9	4.9	4.7	2.9	7.3	7.1	6.7	1.9
1995	4.8	4.7	4.5	2.7	7.2	6.8	7.0	2.6
1996	4.7	4.7	4.3	2.5	7.2	6.9	6.8	2.3
	Total							
	IOU	Publicly	Coop.	Federal				
1990	6.8	5.9	6.8	3.1				
1991	7.0	5.9	6.9	2.8				
1992	7.1	7.0	7.0	2.6				
1993	7.2	6.1	7.0	2.8				
1994	7.1	6.1	7.0	2.8				
1995	7.2	6.0	6.9	2.7				
1996	7.1	6.0	6.7	2.5				

Note: IOU = Investor-owned utility; Publicly = Publicly owned utility; Coop. = Cooperative utility; and Federal = Federal utility.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

marketing authorities), and some cooperative utilities service only the needs of their member utilities and end-use customers. At least some of these and other traditional characteristics may be expected to change with the advent of competition. Existing price differences are likely to be scrutinized more carefully as markets open for competition.

Retail Price Differentials Between Requirement and Non-Requirement Utilities

Many electric utilities have no generating capability. Because they buy capacity and energy from other utilities in order to meet the requirements of their retail customers, they are known as requirement utilities.[16] Electricity is sold to requirement utilities on the basis of firm commitments for all energy or for some minimum level of demand all year around. Such sales are among the most common types of utility-to-utility wholesale transactions. Non-requirement utilities are those that have the capability to meet some or all of their customer demand loads from their own generating resources. Partial requirement utilities can meet some, but not all, of their customer loads.

Requirement utilities negotiate long-term, firm power contracts in which the terms and conditions obligate the selling utility to provide the buying utility a level of service equivalent to the seller's requirement for service to its retail customers.[17] About a third of all retail sales

[16] Full requirement utilities are those that have no capability to meet customer demand because they own no generating resources.
[17] See the next section for a more detailed discussion of wholesale transactions and firm power trade.

are made by utilities with no generating capability. Such utilities comprise two-thirds of all electric utilities.

Price differences among the three categories of utilities—full requirement, non-requirement, and partial requirement—are to be expected. One might expect that retail customer prices of non-requirement utilities (mostly large investor-owned electric utilities) would be lower than those of the requirement utilities (most municipalities and all distribution-only cooperatives), which must buy all the power they sell. However, data reveal that the average price for retail sales by non-requirement utilities is invariably higher than those charged by full requirement or partial requirement utilities (smaller utilities that can generate some of their own electrical energy) when examined at the national level (Table 7). Factors that contribute to this counter-intuitive result may include interutility differences in the cost of capital (resulting from the tax treatment of debt acquisitions), the nonprofit status of some utilities, access to Federal preferential power allocations, and/or differences in fuel costs.

Similar difficulties arise in explaining the prevailing price differentials between full and partial requirement utilities. However, one of the key reasons for the existence of partial requirement utilities points directly to why there is a price difference. Better rates can be negotiated because these utilities limit the amount of power that they buy from the supporting utility. The reason for this is that the supplying utility knows in advance a ceiling amount that it is obligated for and can plan accordingly; it is not faced with an unlimited requirement during times of tight availability of supply. The limits established for these contracts usually have one of the following conditions: a contract demand cap; an average monthly maximum demand level; or an annual maximum demand level. Partial requirement utilities can do this, because they may have negotiated multiple contracts with different supplying utilities, or the partial requirement utility may own a generating power plant that is utilized when end-use demand reaches a specified level. Detailed retail trade statistics are provided in Appendix C.

The Wholesale Market: Trade and Price Issues

Wholesale Trade

The factors that lead to wholesale (interutility) trade in electric power include differences in resource availability, input costs, and comparative advantage in production. For example, abundant water resources to produce hydroelectric power in a given region may make hydroelectricity in that region less expensive than other sources of electricity, especially if the other fuels have to be transported over long distances. In addition, the wholesale market is also governed by considerations of system reliability. Technical details with respect to the fundamentals of power transmission are provided in Appendix D.

Wholesale power transactions include purchases, sales for resale, exchanges, and wheeling (i.e., transmission services) (Figure 6). These wholesale power transactions involve the buying of power and energy from electric utilities according to the tariffs approved by the FERC and its regulations under the Uniform System of Accounts. Purchases from nonutilities follow the requirements of PURPA and EPACT with the result that the generation sales made by nonutilities are only accounted for by electric utilities in the cost account of purchased power and are not considered to be sales. Nonutility generation sold to utilities is accounted for under the category of purchased power. Sales for resale by electric utilities refer to power sold by a utility to one or more utilities for distribution to ultimate customers.

In the changing electric power industry, complete coverage through capture of all transactions poses a problem. As an example, power brokers do not take ownership of electricity purchases or sales, and the transactions they facilitate are not identified in the data collection process. Nor are all the intermediate transactions (purchases and sales) of a power marketer—who does take ownership of electricity and moves it from the point of origin to final delivery to the end-use customer—identified. In the new market for electricity, a single electricity transaction may be resold several times without being reported. Also, the change in value and repackaging of the electricity enables it to be marketed as a differentiated product (in order to meet the hour-by-hour market or achieve a daily balance on all transactions). The prevailing data collection approaches do not capture all these variances. Specifically, data on the market for purchased power (in the aggregate) do not necessarily match data on the market for sales for resale, even though all transactions can eventually be equated to a buyer and seller.

Accordingly, care needs to be exercised in analyzing historical account data by recognizing its limitations in fully capturing all sales transactions in the electric power industry.

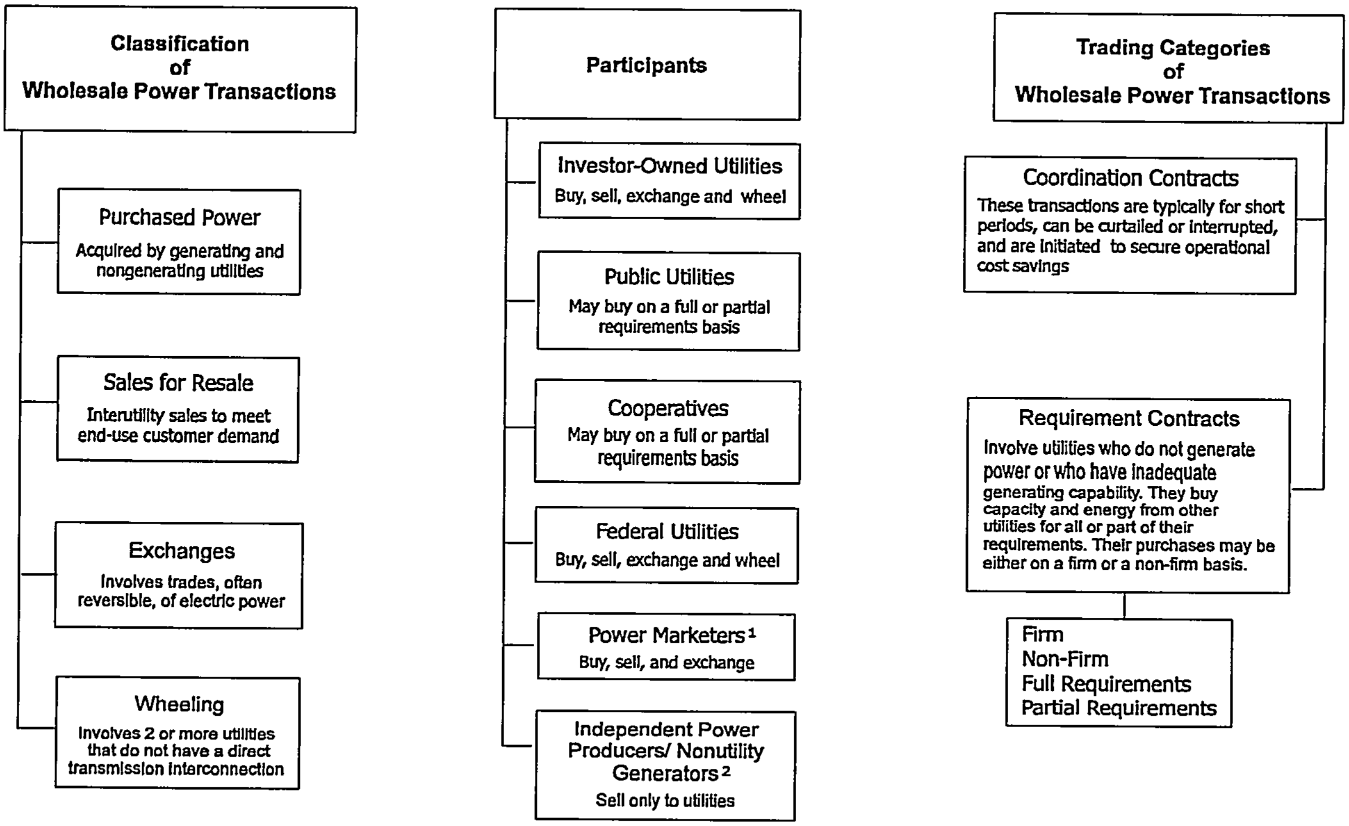
Table 7. Retail Sales, Revenue, and Price by Requirement, Partial Requirement, and Non-Requirement Utilities, 1990-1996

Year	Sales (Billion Kilowatthours)			Revenue (Million Dollars)			Price (Average Cents Per kWh)		
	No Generation	≤ 25 Percent	>25 Percent	No Generation	≤ 25 Percent	>25 Percent	No Generation	≤ 25 Percent	>25 Percent
Residential									
1990	188	3	733	13,181	131	59,066	7.0	4.5	8.1
1991	194	3	759	13,777	139	62,912	7.1	4.5	8.3
1992	192	3	741	13,968	133	62,747	7.3	5.3	8.5
1993	206	2	787	15,047	113	67,653	7.3	4.7	8.6
1994	211	1	797	15,520	75	68,958	7.4	5.6	8.7
1995	216	3	824	15,889	150	71,570	7.4	5.4	8.7
1996	232	4	847	16,751	173	73,578	7.2	4.9	8.7
Commercial									
1990	77	3	671	5,294	104	49,719	6.8	4.2	7.4
1991	80	3	684	5,530	110	52,015	7.0	4.4	7.6
1992	74	2	686	5,286	102	52,954	7.2	5.4	7.7
1993	76	2	717	5,444	86	55,991	7.2	4.9	7.8
1994	78	1	741	5,640	51	57,704	7.2	4.3	7.8
1995	80	2	780	5,761	113	60,491	7.2	5.1	7.8
1996	85	3	799	6,018	145	61,663	7.1	4.8	7.7
Industrial									
1990	99	24	822	4,825	1,079	38,953	4.9	4.4	4.7
1991	101	25	821	4,957	947	39,834	4.9	3.9	4.9
1992	111	23	839	5,462	882	40,649	4.9	3.8	4.9
1993	118	21	838	5,756	821	40,780	4.9	3.9	4.9
1994	122	24	862	5,982	833	41,254	4.9	3.4	4.8
1995	129	50	834	6,203	1,365	39,608	4.8	2.8	4.8
1996	136	47	846	6,433	1,203	39,749	4.7	2.5	4.7
Other									
1990	11	7	74	694	117	5,080	6.3	1.7	6.9
1991	11	5	78	703	109	5,327	6.4	2.0	6.8
1992	10	5	78	680	109	5,508	6.6	2.1	7.1
1993	10	6	79	700	112	5,716	7.0	1.9	7.2
1994	11	6	81	734	107	5,848	6.7	1.8	7.2
1995	11	5	80	742	127	5,698	6.9	2.7	7.1
1996	11	4	82	778	110	5,853	6.9	2.5	7.2
Total									
1990	375	37	2,301	23,994	1,431	152,818	6.4	3.9	6.6
1991	385	36	2,341	24,966	1,304	160,088	6.5	3.7	6.8
1992	387	33	2,344	25,396	1,226	161,858	6.6	3.7	6.9
1993	409	31	2,421	26,947	1,133	170,140	6.6	3.6	7.0
1994	422	33	2,480	27,876	1,066	173,765	6.6	3.3	7.0
1995	436	59	2,518	28,594	1,756	177,367	6.6	3.0	7.0
1996	465	58	2,575	29,980	1,632	180,843	6.5	2.8	7.0

Notes: The data were separated into three groups: utilities that have no electrical generation, utilities that have partial generating capability (≤ 25 percent), and utilities with generating capability (> 25 percent).

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

Figure 6. Wholesale Power—Basic Elements



[1]Power Marketers are considered to be electric utilities. The FERC approves their wholesale tariffs and has oversight responsibilities.

[2]Independent Power Producers do sell to power marketers.

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

Exchanges involve trading power (in-kind) when supply and demand conditions are mutually advantageous and reversible for the participants. Many exchange trades are based on seasonal excess capacity or diversity in generating resource requirements.[18] Exchange-related monetary transactions or replacement of energy can extend over several years; currently, most exchanges seem to be concluded within one year. If a balance cannot be reached at the end of the year, cash compensation may be provided. The volume of exchange transactions has dropped since 1990 (Figure 7), partly because barter (in-kind) transactions have lost their luster. The advantage of in-kind exchanges as a technique to reduce overall dollar payments under cost-of-service regulation is not as important in a competitive market.[19]

Characteristics of Wholesale Trade

Nearly 55 percent of all the electricity consumed in 1996 was purchased by utilities from other utilities and nonutilities.[20] In addition, electric utilities sold to other electric utilities for their resale to retail consumers just over 46 percent of the total energy purchased by those consumers.[21] These percentages make it clear that

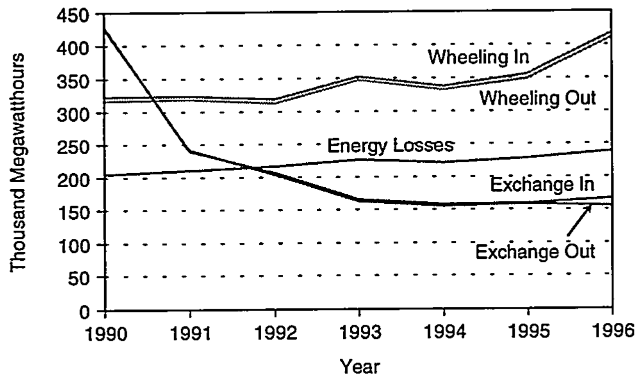
[18] For example, a summer peaking electric utility sells surplus capacity in the winter to a winter peaking utility and receives in-kind trades when the seasons reverse.

[19] The 1990 to 1991 drop represents the FERC enforcement of a statistical cleanup of informational filings. Prior to 1990, the requirements of the Purchased Power Account were fulfilled by the filing, on two separate but very different forms, of information on these transactions. From 1991 onward, competition affected this account.

[20] A total of 3.1 trillion kilowatthours was consumed in 1996. Energy Information Administration, *Electric Power Annual 1996*, Volume 2, DOE/EIA-0348(96/2) (Washington, DC, February 1998), p. 61.

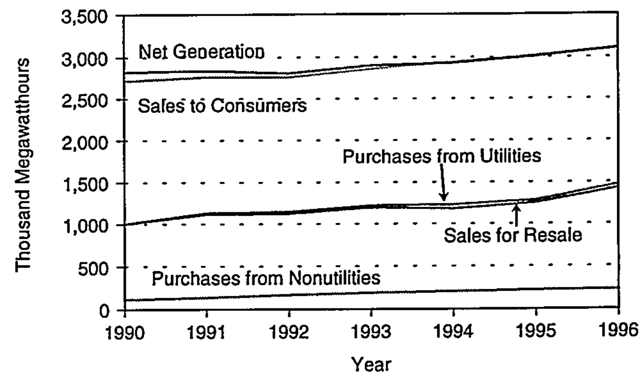
[21] Energy Information Administration, *Electric Power Annual 1996*, Volume 2, DOE/EIA-0348(96/2) (Washington, DC, February 1998), p. 61.

Figure 7. Exchange, Wheeling, and Losses by U.S. Electric Utilities, 1990-1996



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

Figure 8. Purchases, Sales for Resale, Net Generation, and Sales to Consumers by the U.S. Electric Power Industry, 1990-1996

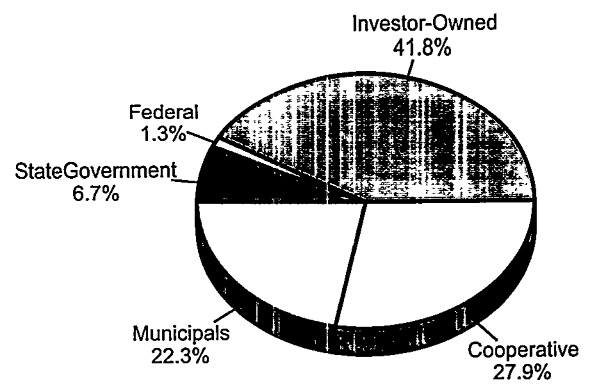


Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

purchases and resales of electricity within the wholesale markets represent a market force in which the prices affect both the source and end-user (generation and retail markets).

As shown in Figure 8, sales to the ultimate consumer have become larger than total utility generation. Electricity purchased from nonutilities must be included in the total sources of electricity supply. Nonutility power supply sources have become integral in meeting the total power demand in the country.[22] In addition to this trend, the recent increase in activities by power marketers has resulted in a relative shift in *sales for resale.* The reason is threefold. First, both the *purchased power* and *sales for resale* markets have been altered by the addition of competition as another aspect of trading, and the two markets are no longer in tandem. The market for *purchased power* is affected by nonutility generation and is oriented toward supplying utility needs (Figure 9), whereas the *sales for resale* market, which is influenced by power marketers, is directed toward end-use customers (Figure 10). Second, more transactions are conducted with an increasing number of trading participants involving trade over longer distances. Third, information on power marketers is not collected at the same level as information on electric utilities, nor are all the power marketers' transactions identified. What is known about the new sales for resale market is that many transactions can go through a dozen or more parties before reaching the end-use customer.[23] As

Figure 9. Market Share of Purchased Power By Utility Sector, Average of Selected Years, 1990-1996



Note: Averages calculated from 1990, 1992, 1994, and 1996 data.

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

electricity markets become more competitive, this trend is likely to become more pronounced.

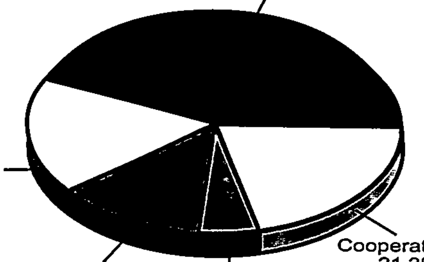
Coordination and Requirements Wholesale Contracts

Wholesale trade transactions are also categorized in another fashion, as coordination and requirements

[22] This argument can be countered by positing that existing regulations require all nonutility generated power to be bought.

[23] Power marketers balance their hour-by-hour and daily exposure on contract commitment. Surplus power and energy (or shortages) along with new opportunities need to be addressed daily. (Information developed based on conversations with industry representatives and system operators.) Industry analysts contend that the volume of commodity trades in electricity will soar to $2.5 trillion by the year 2003. This estimate is based on the experience of the natural gas industry, where trading is 10 times the value of physical sales. For more information, see the *Electricity Journal* (March 1998), p. 6.

Figure 10. Sales to Resale Market Share by Utility Sector, Average of Selected Years, 1990-1996



Note: Averages calculated from 1990, 1992, 1994, and 1996 data.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

contracts. Coordination service generally involves the purchase, sale, exchange, or transmission of electricity between two or more electric utilities that typically have sufficient generation and transmission capacity to supply their customer load requirements under normal conditions. These transactions are usually entered into because of advantageous prices, to sell surplus electricity, and/or to use a lower cost generation resource. Requirements transactions involve electric utilities that do not generate or have sufficient generating capacity to meet their customer load; in addition, these utilities may not have sufficient transmission capability to carry the electrical energy to the point where it would be transformed to a lesser voltage for distribution to consumers. Thus, in reality, requirements transactions involve handling part or all the firm service needs of another electric utility.

Requirements utilities (see above) usually enter into long-term contracts that identify the designated load level (partial obligations) or all current and future load (full obligations) of customers in their service territories.

Magnitude of Requirements Contracts

Requirements contracts are critical, because fewer than 1,000 of the 3,195 electric utilities in the United States are engaged in power generation.[24] Thus, more than two-thirds of utilities must acquire their electrical energy through long-term contracts to meet their end-user customer loads. In finalizing contracts, the most critical element is the certainty for delivery of power.[25] This certainty or the degree of assuredness (of power supply) determines the price formulation that a utility will be called upon to pay.

Price Determination in Requirements Contracts[26]

Where assuredness of power delivery (also known as firm power) is a must, transactions command premium prices, in comparison with contracts that do not require such a commitment. The premium on prices for requirement contracts depends on the degree of assuredness a supplier offers (all other conditions being equal). Within the class of requirements contracts, if a utility places a requirements wholesale customer (another electric utility) before its own end-use (retail) customers, then that level of contract service will be valued at the most expensive price level and will command the highest price premium. The next tier is where almost all requirements contracts are found. The utility that is providing the service will put serving its own retail customer base and the receiving retail customer base on the same level. This implies that the customer base of a wholesale requirements utility will not be cut before the supplying utility cuts its own retail customers. Instead, other transactions (i.e., spot or economic sales) are cut first, then interruptible retail customers are cut next, and finally a rolling blackout is initiated to reduce the impact on all retail customers. Structuring the contract somewhat differently brings about a different set of conditions together with variations in price premiums.

Other categories of customers are also included. Partial requirements customers (electric utilities) are those that have only a portion of their end-user load protected. They have a set block of power and energy allocated for their use. Finally, there are utilities with plants that are run only when the utility is approaching its prior system high usage level. This lowers the system demand level (peak load) to avoid setting a high usage power value. That value or peak load is used as the basis for setting the requirements contract price for the rest of the

[24] Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

[25] Other elements (for both coordination and requirements contracts) in determining the type and value of transactions are the duration of the purchase/sale, the amount of energy, and the type of generating capacity sold, excluded, or reserved.

[26] The capacity charge represents an element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity or demand charge is assessed on the amount of capacity being purchased. The terms "capacity charge" and "demand charge" are used interchangeably in the text.

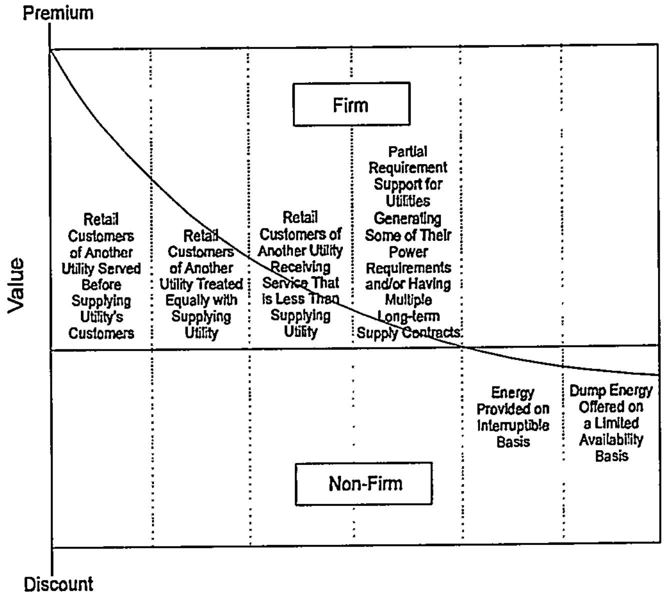
electrical energy and power sold during other times of the year (or contract period). Overall, requirements contracts usually contain a reservation of capacity that is on-call (sometimes called a demand charge), which must be paid, and then a separate charge for the actual energy used. Transmission costs and other electrical system charges are included in the bundled cost.

There are other firm transactions that involve electric utilities with adequate generation and transmission capability. These transactions include a capacity reservation charge and an associated energy charge. They are often entered into to provide or add additional electrical system support for the utility's own customer base. Each utility is required to have spinning and standby generation capacity on-call that would be used to replace operating power plants that suffer a forced outage and go off-line, or is needed to reinforce another part of the electrical system if a transmission line is lost. It is often more economic to purchase and/or join with other utilities in sharing backup capacity than to operate additional generating capability alone. Scheduled or forced plant maintenance of one of its power plants can also cause an electric utility not only to purchase reserve capacity but also to acquire the produced electrical energy. In addition, there are operating periods during which it is cheaper to purchase or sell firm capacity in order to keep a power plant operating at its most efficient cost levels.

Coordination Contracts

Coordination contracts—economic, interruptible, or non-firm sales and purchase contracts—are next on the price scale, followed by dump power transactions. Non-firm sales rarely have a demand or capacity charge included in the price of the transaction. These transactions are typically for short periods and are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions. Utilities engage in these transactions in order to gain operational savings, such as avoiding the use of more expensive fuels. Dump energy is the cheapest priced electricity. The opportunity for this sale develops when electricity is generated by the spillage of excess reservoir water (and also for run-of-river dams) through a water-driven turbine-generator. This happens because there is no way to store the excess moving water behind dams, and if the turbines are not run, then all the potential energy is lost. These transactions are thus low priced, depending on what the supplier can obtain at a given point in time in the market (Figure 11).

Figure 11. Conceptualization of Premium Payments in Electricity Trade



Note: This is a conceptualized presentation rather than a statistical chart.

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

Regional and Interregional Trade

A significant portion of the electricity generated in the United States is traded under wholesale purchases and sales for resale contracts. The vast majority of wholesale transactions for investor-owned, Federal, and cooperative utilities involve utilities within existing NERC regions (Figure 4). Existing differences between intra- and interregional wholesale trade are attributable to the historical development of multiple transmission links among clusters of neighboring utilities.

Investor-owned electric utilities have led other ownership classes in total purchases and sales for resale, accounting for more than 40 percent of purchased power and sales for resale. The different shares of the wholesale market by other classes of utilities are shown in Table 8. Of this total, transactions with municipalities and power purchases from nonutilities are a dominant part of investor-owned trade.

The remaining categories of miscellaneous and other sales and purchases account for a wide range of trade covered by the terms and conditions in specific tariffs

Table 8. Market Share of Wholesale Trade, Various Years
(Percent)

	Sales For Resale				
	1990	1992	1994	1996	Average
Investor-Owned	38.6	45.1	43.6	45.0	43.1
Federal	19.6	16.6	16.8	17.4	17.6
State Government/Other	15.0	12.4	12.7	11.7	13.0
Municipal	4.7	4.8	5.2	5.3	5.0
Cooperative	22.1	21.1	21.7	20.5	21.3
					100.0
	Purchased Power from Electric Utilities				
	1990	1992	1994	1996	Average
Investor-Owned	37.9	42.8	41.0	45.5	41.8
Federal	1.0	1.6	1.6	0.9	1.3
State Government/Other	7.6	6.4	6.8	5.9	6.7
Municipal	24.4	22.0	22.3	20.4	22.3
Cooperative	29.0	27.1	28.2	27.3	27.9
					100.0
	Purchased Power from Nonutilities				
	1990	1992	1994	1996	Average
Investor-Owned	97.5	98.9	98.9	98.1	98.3
Federal	0.8	0.2	0.1	0.9	0.5
State Government/Other	0.4	0.1	0.2	0.2	0.2
Municipal	0.9	0.5	0.7	0.6	0.7
Cooperative	0.4	0.2	0.1	0.2	0.2
					100.0

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

filed with the FERC. Many of these trades are associated with agreements that include transmission line capacity and equipment rental charges that grew up with the electric utility industry. These transactions are likely to continue until institutional changes, such as the formation of independent system operators (ISOs) and the Open Access Same-Time Information System (OASIS), become fully operational (or become part of a revised version of an open access to the wholesale/retail transmission system).

Quantity, Cost, Revenue, and Average Price

Table 9 shows the quantity of purchased power and sales for resale that investor-owned electric utilities have made since 1990. Overall, the quantity of purchased power has been increasing each year, from 563.4 million megawatthours in 1990 to 843.4 million megawatthours in 1996, reflecting an increase of nearly 50 percent overall. The proportion of firm to non-firm power purchases has also been changing during this period. In 1990, 57.6 percent of power purchased was on a firm basis, and only 39 percent was from non-firm sources. These percentages changed to 43.2 and 54.1 percent, respectively, in 1996. These statistics reflect the shifting character of the purchased power trade as utilities proceed to open electricity markets to competition (non-firm power purchase prices are invariably lower than the prices for firm power purchases, with an appropriate tradeoff for assuredness of supply). The shares of firm and non-firm power in the sales for resale category have followed a similar directional change.

An analysis of the cost of firm and non-firm power purchases by investor-owned utilities (Table 10) shows the following. First, demand charges, which constitute a fraction of the total firm cost (about 1 percent), have been growing rapidly, indicating that firms are willing to pay for reservation of capacity rights. Second, nearly 57 percent of the cost of purchased power in 1996 represented firm demand charges and firm energy costs. Third, the cost of firm energy has consistently been more than the actual firm demand charge.

Table 9. Sales for Resale and Purchases by Investor-Owned Electric Utilities, 1990-1996
(Gigawatthours)

	Firm	Non-Firm	Miscellaneous	Total Quantity
Purchased Power				
1990	324,542	219,700	19,127	563,368
1991	324,851	275,754	17,208	617,813
1992	342,472	299,666	16,460	658,599
1993	359,217	316,438	22,196	697,850
1994	361,709	326,490	24,313	712,512
1995	372,613	361,596	24,288	758,496
1996	364,273	456,442	22,658	843,373
Sales for Resale				
1990	253,809	182,809	7,563	444,181
1991	268,119	221,129	6,585	495,832
1992	269,376	237,409	7,585	514,370
1993	274,350	260,350	8,756	543,456
1994	258,073	255,237	16,312	529,622
1995	301,339	227,399	17,202	545,941
1996	295,403	294,022	19,056	608,482

Source: Energy Information Administration, Wholesale Electric Trade Data Base, 1990-1996. Data for 1996 are preliminary.

Table 10. Cost of Firm and Non-Firm Purchases by Investor-Owned Electric Utilities
(Million Dollars)

	Demand Charge Only	Firm Demand	Firm Energy	Firm Other	Total Firm Cost
1990	118	6,536	7,224	545	14,306
1991	127	7,264	7,522	379	15,165
1992	181	7,643	8,356	353	16,352
1993	179	8,306	8,784	344	17,433
1994	185	8,820	8,860	328	18,007
1995	190	8,602	8,882	254	17,737
1996	179	8,792	9,395	288	18,476

	Non-Firm Energy	Non-Firm Other	Miscellaneous	Total Cost
1990	6,306	1,019	284	22,034
1991	7,486	931	335	24,045
1992	8,251	1,248	274	26,306
1993	8,736	1,150	487	27,986
1994	9,294	1,231	626	29,343
1995	9,980	1,325	549	29,781
1996	11,451	1,362	597	32,064

Source: Energy Information Administration, Wholesale Electric Trade Data Base, 1990-1996. Data for 1996 are preliminary.

In sales for resale, firm sales provide a major share of the total revenues (Table 11). The value of reservations (i.e., demand or capacity charges) has risen sharply, even though these charges are a small fraction of the total. It is also interesting to note that firm demand (or capacity) charges are higher or about the same as the cost of firm energy, in contrast to their shares of purchased power transactions. Non-firm sales have held relatively constant, indicating that there is willingness prevailing in the markets to pay a significant premium for

Table 11. Revenue from Firm and Non-Firm Sales for Resale by Investor-Owned Electric Utilities
(Million Dollars)

	Demand Charge Only	Firm Demand	Firm Energy	Firm Other	Total Firm Revenue
1990	10	4,600	4,701	526	9,828
1991	14	5,080	4,931	475	10,487
1992	25	5,060	4,820	525	10,406
1993	50	5,219	4,801	572	10,593
1994	47	5,395	4,617	437	10,449
1995	104	5,645	5,360	417	11,422
1996	48	5,211	5,435	480	11,125
		Non-Firm Energy	Non-Firm Other	Miscellaneous	Total Revenue
1990		5,400	616	296	16,149
1991		5,845	690	353	17,389
1992		6,374	812	390	18,007
1993		6,770	912	408	18,733
1994		6,297	820	636	18,249
1995		5,395	825	676	18,422
1996		6,719	847	703	19,442

Source: Energy Information Administration, Wholesale Electric Trade Data Base, 1990-1996. Data for 1996 are preliminary.

assurance of supply. Even as trading practices change—and assuming that utilities are able to secure supplies from alternative sources in a competitive environment—it is not clear whether there would be a perceptible decline in the premium paid for firm power. For the spread between firm and non-firm prices to narrow, the requirement that excess capacity should invariably exist in a competitive market is not yet a given (a surplus puts a damper on price increases). In addition, there could be other constraints as well. As a result, the spread between firm and non-firm prices will continue to exist for the foreseeable future.

For the most part, average purchased power and sales for resale prices have remained steady or have been contained since 1992 (Table 12). It is, however, interesting to note that the average prices paid by the industrial sector during the same time period are nearly the same as the wholesale prices for firm power. For any additional savings that this sector may seek, opportunities may lie in purchasing non-firm power (or interruptible power) or in getting the same terms as embodied in requirements contracts. Should the industrials choose to adopt this option, some measure of protection would be necessary to guard against the possibility of actual power interruptions and other risk uncertainties. Additional advantages that this sector may be able to secure in the future as marketing opportunities open up are difficult to predict.

Table 12. Average Price of Electricity for Wholesale Trade by Investor-Owned Electric Utilities
(Cents per Kilowatthour)

Year	Purchased Power				Sales for Resale			
	Firm	Non-Firm	Misc.	Total	Firm	Non-Firm	Misc.	Total
1990	4.4	3.3	1.5	3.9	3.9	3.3	3.9	3.6
1991	4.7	3.1	1.9	3.9	3.9	3.0	5.4	3.5
1992	4.8	3.2	1.7	4.0	3.9	3.0	5.1	3.5
1993	4.9	3.1	2.2	4.0	3.9	3.0	4.7	3.4
1994	5.0	3.2	2.6	4.1	4.0	2.8	3.9	3.4
1995	4.8	3.1	2.3	3.9	3.8	2.7	3.9	3.4
1996	5.1	2.8	2.6	3.8	3.8	2.6	3.7	3.2

Source: Energy Information Administration, Wholesale Electric Trade Data Base, 1990-1996. Data for 1996 are preliminary.

Table 13 provides a cross-sectional representation of the average prices paid and received by investor-owned electric utilities among the different competing utility ownership classes. Federal utility prices (Table 14) are generally lower. The prevailing lower price of power sold by Federal and State utilities at wholesale makes it a valuable commodity. Most of it is based on hydro-electric generation, which has traditionally been an inexpensive source of energy. Potential changes may occur if Federal utilities are no longer required to sell power at cost, or if it commands a premium because of its environmentally benign character. The willingness of retail customers to pay a premium for renewable energy (a large part of which will be hydro-based) in order to spur the development of more renewable energy sources could very well change the pricing of wholesale energy produced from hydroelectric resources.

The "other" category represents a collection of different markets. It includes power pool transaction trades, international electricity trade with Canada and Mexico, and nonutility generation purchases. The sales for resale side represents more of the power pool, firm, and non-firm international trade transactions; the purchased power side includes nonutility purchased generation.

Table 13 shows that there are pronounced differences among the average prices paid and received for firm, non-firm, and the residual miscellaneous energy categories. As new markets develop, the differences in average wholesale prices to utilities, nonutilities, and retail consumers will narrow. Participants in the new markets will include electric utility traders, power marketers, industry, other retail groups, and members of the financial markets. These new and old participants will alter what must be taken into account to determine the true price of electricity, even as they change the existing framework of the retail and wholesale markets for electricity.

Emerging Issues

Competition is viewed as the means to open the wholesale and retail electricity markets. The expectation is that market forces will lead to lower rates for customers. This transition will induce many far-reaching changes in the structure of the industry and the institutions that regulate it. The transition will also raise many issues of reliability as new players, such as power marketers, begin operating and the responsibilities held by electric utilities are altered.

Views on how the emerging issues should be treated remain divided. There are those who would let the market find solutions. Others wish to impose strict, mandated regulatory measures. As a result, the search for consensus is difficult. Some of these emerging issues are stated below.

- Planning for new demand and generating capacity, in the past, has been undertaken by the electric utilities serving a franchised area. The experience of investor-owned utilities in planning and building capacity in the aftermath of the oil embargo of 1973 turned out to be a serious financial problem as demand failed to materialize.[27] With many providers selling power at wholesale or retail level in the future, utilities could exercise the option of either being distributors (implying complete divestiture) with only an obligation to connect or being competitors but without the obligation to be the supplier of last resort (i.e., to serve). Thus, who will plan for new generating and transmission capacity to satisfy future demand—so vital to reliability—becomes a critical issue.

- FERC Orders 888 and 889 encourage utilities operating under FERC's jurisdiction to transfer the management of transmission facilities to ISOs. Utilization of existing transmission facilities could increase as opportunities for trade increase. In some cases, key transmission links and portions of the electrical system will be used to their permissible limits. In this environment, how planning will be undertaken (expand capacity, meet the emerging need for new transmission lines, determine who will build them, and perhaps transfer the management to a third party) remains unclear.

- Local governments stand to lose tax revenues if the valuations of generating plants are reduced due to competition, or if out-of-State suppliers begin selling power. In some cases, revenue losses could be acute and cause community hardships. Countervailing measures to provide revenue-neutral initiatives have yet to be implemented.

[27] This is not to deny the role of integrated resource planning activities with participation of public utility commissions and the stakeholders, including nonutilities. Given that there will be many providers serving a given area, the future of integrated resource planning is unclear.

Table 13. Average Wholesale Price for From and To Trade by Investor-Owned Electric Utilities
(Cents per Kilowatthour)

	Purchased Power				Sales for Resale			
	From IOU and Bought by IOU				To IOU and Sold by IOU			
IOU	Firm	Non-Firm	Misc.	Total	Firm	Non-Firm	Misc.	Total
1990	4.0	2.9	1.6	3.5	3.8	3.6	3.1	3.7
1991	4.3	2.8	2.7	3.7	3.9	3.4	5.0	3.7
1992	4.3	2.8	2.5	3.6	3.8	3.5	4.9	3.7
1993	4.3	2.7	2.9	3.7	3.7	3.5	4.8	3.7
1994	4.3	2.7	2.9	3.6	3.9	3.1	3.9	3.6
1995	4.3	2.7	3.0	3.6	3.8	3.1	4.7	3.6
1996	4.5	2.4	3.3	3.5	3.7	3.0	3.9	3.4
	From IOU and Bought by Federal				To Federal and Sold by IOU			
Federal	Firm	Non-Firm	Misc.	Total	Firm	Non-Firm	Misc.	Total
1990	3.4	1.7	2.4	2.3	4.6	2.4	–	2.6
1991	3.6	1.9	3.1	2.3	5.3	2.0	–	2.6
1992	2.5	2.3	–	2.4	5.9	2.1	–	2.5
1993	2.1	2.0	1.8	2.5	3.2	2.5	–	2.7
1994	3.1	2.5	–	3.3	4.8	2.3	–	2.7
1995	2.4	1.7	–	2.0	4.3	2.0	1.4	2.8
1996	2.5	1.5	–	1.8	4.0	2.1	–	2.8
	From IOU and Bought by State				To State and Sold by IOU			
State	Firm	Non-Firm	Misc.	Total	Firm	Non-Firm	Misc.	Total
1990	4.7	2.3	1.3	2.9	4.4	2.7	2.5	4.0
1991	3.4	2.1	1.4	2.7	4.5	2.8	1.0	4.1
1992	3.4	2.6	1.5	2.9	4.3	2.7	16.5	3.8
1993	4.6	2.2	1.7	2.8	4.2	2.9	7.2	4.0
1994	2.7	2.4	1.5	2.7	4.9	2.4	–	3.9
1995	2.7	1.8	1.4	2.2	4.2	1.7	22.4	3.5
1996	2.5	1.3	1.3	1.8	4.1	1.7	–	3.2
Municipalities	From IOU and Bought by Municipalities				To Municipalities and Sold by IOU			
	Firm	Non-Firm	Misc.	Total	Firm	Non-Firm	Misc.	Total
1990	5.7	2.6	3.7	4.4	4.2	3.5	8.3	4.0
1991	5.5	2.1	4.4	3.7	4.2	3.2	5.3	3.9
1992	5.1	3.4	4.7	4.5	4.1	3.4	–	3.9
1993	5.3	3.8	3.8	4.7	4.0	3.2	1.6	3.9
1994	6.0	3.2	–	5.0	4.0	3.0	7.3	3.8
1995	5.9	3.8	0.3	5.0	3.9	2.9	–	3.7
1996	4.8	3.2	–	3.9	3.7	2.9	7.8	3.5
	From IOU and Bought by Cooperatives				To Cooperatives and Sold by IOU			
Cooperative	Firm	Non-Firm	Misc.	Total	Firm	Non-Firm	Misc.	Total
1990	3.6	3.7	1.7	3.6	4.0	3.9	9.1	4.0
1991	3.7	3.9	1.3	3.3	4.0	3.5	5.7	3.9
1992	3.7	3.8	0.9	3.0	4.1	3.6	2.2	4.0
1993	3.7	2.8	0.5	3.2	4.2	3.3	–	3.9
1994	4.7	2.2	0.5	3.3	4.4	3.4	–	4.2
1995	4.2	2.0	0.3	2.9	4.6	3.3	25.2	4.2
1996	3.4	1.9	0.5	2.5	4.4	2.4	–	4.0

Note: IOU = Investor-owned utility; Federal = Federal utility; State = Publicly owned utility.
Source: Energy Information Administration, Wholesale Electric Trade Data Base, 1990-1996. Data for 1996 are preliminary.

Table 13. Average Wholesale Price for From and To Trade by Investor-Owned Electric Utilities (Continued)
(Cents per Kilowatthour)

Other	Purchased Power: From IOU and Bought by Other Entities: Firm	Non-Firm	Misc.	Total	Sales for Resale: To Other Entities and Sold by IOU: Firm	Non-Firm	Misc.	Total
1990	4.8	4.7	–	4.8	3.2	2.4	–	2.8
1991	5.4	3.8	–	4.7	3.1	2.2	–	2.4
1992	5.6	3.8	–	4.7	2.8	2.4	9.3	2.5
1993	5.5	3.7	–	4.6	3.6	2.3	5.3	2.4
1994	5.8	3.8	3.6	4.8	3.3	2.3	3.6	2.4
1995	5.5	3.9	–	4.6	2.6	2.2	1.7	2.3
1996	6.1	3.6	–	4.7	2.8	2.2	2.2	2.3

Note: Other entities = power pools, international trade, and nonutility purchases.
Source: Energy Information Administration, Wholesale Electric Trade Data Base, 1990-1996. Data for 1996 are preliminary.

Table 14. Electricity Purchases and Sales by Federal Utilities, Fiscal Year Ending September 30, 1995
(Cents per Kilowatthour)

Utility	Purchased Power: IOU	Fed	State	Municipals	Coop	Other[a]	Total
Bonneville Power Administration	2.3	--	1.8	2.1	2.9	2.1	2.3
Southeastern Power Administration ...	1.5	--	1.4	--	1.6	1.6	1.5
Southwestern Power Administration ...	6.1	--	--	--	-	-	6.1
Tennessee Valley Authority [b]	--	0.9	--	--	-	1.7	0.6
USBIA-Mission Valley Power	1.5	2.8	--	--	-	2.7	2.4
Western Power Administration	3.0	2.1	1.6	4.1	1.4	3.7	2.7
U.S. Total	**2.1**	**1.1**	**1.6**	**3.5**	**1.7**	**2.5**	**2.1**

	Sales for Resale: IOU	Fed	State	Municipals	Coop	Other[a]	Total
Alaska Power Administration	3.2	-	-	1.7	1.7	-	2.6
Bonneville Power Administration	3.4	2.7	2.7	2.6	2.6	1.5	2.7
Southeastern Power Administration ...	-	1.0	-	-	-	2.8	2.3
Southwestern Power Administration ...	0.5	2.0	1.1	1.3	1.3	2.3	1.3
Tennessee Valley Authority	-	-	-	4.2	4.3	4.3	4.2
US Army Corps of Eng. – Illinois	1.3	-	-	-	-	-	1.3
Western Power Administration	1.7	1.2	2.9	1.8	1.7	1.4	2.1
U.S. Total	**3.0**	**1.5**	**2.7**	**3.7**	**3.4**	**2.6**	**3.4**

[a]Includes transactions with power pools, utilities in Canada and Mexico, and nonutilities.
[b]No payment received for movement of 1.5 billion kilowatthours for Tapoco, Inc.
– = No Transactions
Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

- Other unresolved issues include service to the poor and to rural customers, retaining public benefit programs, and some aspects of billing and metering.

The above issues do not lend themselves to a market-devised resolution in the initial stages. For example, the task of requiring the present transmission owners to build and hand over transmission facilities to independent managers may prove difficult to implement. States are grappling with these issues.

Conclusions

Over two-thirds of the electric utilities in the United States do not generate electricity and depend upon other utilities for their supply of electricity. These utilities, known as requirement utilities, have historically shown a willingness to pay significant premiums for assurance of supply (that is, for requirements service). Even with electricity markets opening to competition and with changes in trading practices, these utilities will be operating under the terms of existing long-term contracts. Accordingly, it is not certain that the premium for firm power supplies (for requirement contracts) will decline in the immediate future. To the extent that firm power purchases represent a unique market product, premiums for firm requirement contracts (other things being equal) may continue to exist for the foreseeable future.

Non-firm electricity sales and purchases are priced lower than firm energy because of the limited availability of this category of electrical energy and the interruptible nature of the power supply. As part of the managed acquisition of future energy supplies, and as a means to cap the overall price paid for electrical supply, the acquisition of both firm and non-firm supplies of electricity can be expected to continue.

Industrial customers, in the aggregate, have secured price reductions during the 1992-1996 time frame, paying prices that are approximately equal to the wholesale prices for firm power. During the same time period, the per-kilowatthour price for retail customers in the residential and commercial sectors has increased. The large investor-owned electric utilities have also responded by cutting internal costs, and the average wholesale selling price has shown a corresponding decline.

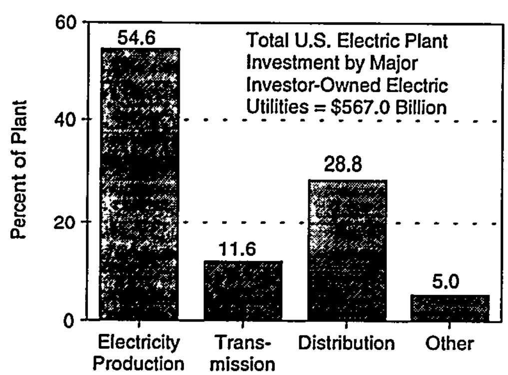
Regional electricity markets are characterized by price differences. The competitive push to acquire cheaper electricity will result in more trade among divergent price regions. This development may strain wholesale transmission carrying capability, with associated impacts on reliability standards. If competitive electricity markets are unable to resolve these issues, alternative methods of resolution may become necessary.

3. Development of Independent Transmission System Operators

Introduction

The electric power industry has three major components: power generation, the bulk power transmission grid, and local distribution grids. Power generation plants produce electric power, bulk power transmission systems route the electric power to distribution systems, and distribution systems deliver electricity to retail customers. Power generation is the most expensive component, representing 55 percent of major investor-owned utilities' plant investment. Transmission represents 12 percent and distribution 29 percent (Figure 12). Although power generation is the largest investment, all components are integral. The bulk power transmission system is necessary because it enables utilities to deliver power over long distances. This capability increases the potential for competition by providing electricity customers an opportunity to purchase less expensive power from distant suppliers. A market in which customers have a choice of electricity suppliers is essential for a competitive industry to flourish.

Figure 12. Percent Distribution of Net Electric Utility Plant Investment, 1996



Source: Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996*, DOE/EIA-0437(96/1) (Washington, DC, December 1997).

An Overview of the Bulk Power Transmission System

As discussed previously (see Chapter 2), the U.S. bulk power transmission system is directly serviced by three of the five electric networks (power grids) in North America, consisting of extra-high-voltage lines designed to permit the transfer of electric energy across the network. The three networks are: the Eastern Interconnected System, consisting of the eastern two-thirds of the United States; the Western Interconnected System, consisting primarily of the Southwest and areas west of the Rocky Mountains; and the Texas Interconnected System, weakly interconnecting with the others by direct current lines. The other two networks have limited interconnections. Both the Western and Texas Interconnects are linked with parts of Mexico. The Eastern and Western Interconnects are 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 major grids except Alaska and Hawaii. Within each power grid, utilities that own or control generation and transmission buy and sell power among themselves.

To operate the systems safely and reliably, and to provide dependable electric service to their customers, the interconnections are divided into 152 regional "control areas" that monitor and control a regional transmission grid. Control areas are the primary units responsible for the reliable operation of the transmission system. Among other things, control areas designate the generators to operate (unit commitment), schedule power trades between control areas (transaction scheduling), and schedule electricity generation from each generator (unit dispatch).[28] The Eastern Interconnection has 109 control areas, the Western has 33, and the Electric Reliability Council of Texas (ERCOT) has 10, for a total of 152 control areas.[29]

[28] General descriptions of control areas and their function are contained in North American Electric Reliability Council, Control Area Concepts and Obligations (July 1992), and a report prepared by Paul A. Centolella, Science Application International Corporation, for the National Council on Competition and the Electric Industry, *The Organization of Competitive Wholesale Power Markets and Spot Price Pools* (October 1996).

[29] The control areas are listed on the web site www.tsin.com.

To improve operating efficiencies, some utilities have created regional power pools to coordinate the operation and planning of generation and transmission among their members. Centrally dispatched power pools achieve increased efficiencies by selecting the least-cost mix of generating and transmission capacity, by coordinating maintenance of units, and by sharing operating reserve requirements.[30] Some power pools function as control areas (tight power pools); others have more limited roles (loose power pools). Utility holding companies and other large utilities often use methods similar to tight pools, referred to as affiliate power pools, to improve operating efficiency. The United States has 22 centrally dispatched power pools and large utilities (see box). Through resource sharing and least-cost dispatching, these centrally dispatched pools and large multi-plant utilities are able to reduce operating costs and thus lower the costs to end-use electricity customers (Appendix D contains additional discussion of the control and operation of electric systems).

Centrally Dispatched Power Pools and Large Utilities in the United States

Tight Power Pools

- New England Power Pool (NEPOOL), covering the six New England States
- New York Power Pool (NYPP), including the utilities located in New York State
- The Pennsylvania, New Jersey, Maryland (PJM) Interconnection Association, which encompasses New Jersey, Maryland, most of Pennsylvania, Delaware, Washington, DC, and a small part of Virginia
- Colorado Power Pool, which permits Public Service of Colorado to dispatch generation for three smaller utilities
- Texas Municipal Power Pool, covering municipally owned generation.

Large Utility Holding Companies

- American Electric Power (AEP), serving parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia
- PacifiCorp., serving parts of California, Idaho, Montana, Oregon, Utah, Washington, and Wyoming
- The Allegheny Power System (APS), serving parts of Ohio, Maryland, Pennsylvania, Virginia, and West Virginia
- The Southern Company, providing service to Alabama, Georgia, and parts of Florida and Mississippi
- Entergy, serving parts of Arkansas, Louisiana, Mississippi, and Texas
- Texas Utilities, serving a large portion of Texas
- Central and Southwest System, serving parts of Texas, Oklahoma, and Arkansas.

Other Major Utilities (that dispatch more than 10,000 megawatts of generation)

- The Northern Indiana Public Service Co., serving northern Indiana
- The Tennessee Valley Authority (TVA), serving Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia
- Southern California Edison, serving southern, coastal, and central California[a]
- Unicom (Commonwealth Edison), serving northern and central Illinois
- Duke Power, serving the Piedmont region of North Carolina and South Carolina
- Florida Power and Light Co., serving southern and eastern Florida
- Pacific Gas and Electric, serving northern and central California[a]
- The Bonneville Power Administration, supplying power to utilities and industrial customers in the Pacific Northwest
- Virginia Electric Power, serving parts of Virginia and North Carolina
- Houston Lighting and Power, serving the Gulf Coast region of Texas.

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[a] These utilities are members of the newly created California Independent System Operator, which performs functions similar to those of a tight power pool.

Source: Adapted from National Council on Competition and the Electric Industry, *The Organization of Competitive Wholesale Power Markets and Spot Price Pools* (October 1996).

[30] Report prepared by Paul A. Centolella, Science Applications International Corporation, for The National Council on Competition and the Electric Industry, *The Organization of Competitive Wholesale Power Markets and Spot Price Pools* (October 1996).

Emergence of the Independent System Operator Concept

Advances in technology, growth in the number of power suppliers, and passage of Federal and State legislation have made power generation more competitive over recent years. Access to the bulk power transmission system, however, was limited, and the full effects of a competitive generation sector were not realized by all. Many vertically integrated electric utilities did not allow other utilities or other energy suppliers access to their privately owned transmission grids, or if they did, they tended to favor their own power generation when transmission resources were limited. Power pools controlling access to large regional transmission systems made it difficult to use pool members' transmission facilities by having complex operating rules and financial arrangements for non-pool members. Also, restrictive membership and governance of the pools were such that a small group of large utilities had the ability to block changes in operating policies designed to open pool membership or improve operating procedures.[31] These industry practices severely limited the growth of a competitive power generation market.

The Energy Policy Act of 1992 gave the Federal Energy Regulatory Commission (FERC) authority to order bulk power transmission owners to provide access to their transmission grids to third parties when requested. This helped make the transmission system more accessible to outside customers, but in many instances transmission customers did not receive the flexibility of service that transmission owners retained for themselves. Also, timely permission to use the grid sometimes did not occur, because the FERC had to review requests on a case-by-case basis.

The FERC's Order 888 (issued April 24, 1996) includes provisions to correct these problems. Briefly, it requires utilities owning bulk power transmission facilities to treat any of their own new wholesale sales and purchases of energy over their own transmission facilities under the same transmission tariffs they apply to others. This is called comparable service. To implement comparable service, each transmission-owning utility under the FERC's jurisdiction filed a *pro forma* tariff, specifying the terms and conditions of transmission service applicable to all eligible customers. Still, some regulators and industry participants believed that this would not be adequate to eliminate favoritism and discriminatory practices of transmission owners, and that stronger approaches were needed. The concept of separating transmission ownership from transmission control was thought by many industry players to be an effective complement to the *pro forma* tariff.

Separation of ownership from control started in the California restructuring debate. In 1994, two California utilities (San Diego Gas & Electric Company and Southern California Edison Company) proposed a regional company that would have operating control of some or all generators and all transmission facilities.[32] This evolved and expanded into the independent system operator (ISO) concept, where the transmission system is independently operated. Since the California proposal, the ISO concept (supplemented by the FERC's endorsement) has gained momentum. ISOs are now being formed in many regions of the United States. The FERC has indicated that a properly structured ISO can be an effective way to eliminate discriminatory practices in transmission and to comply with Order 888.

Expected Benefits and Potential Limitations of the ISO

The expected benefits of an ISO are more than just ensuring equal and fair access to the transmission system. By sharing resources, and by having central dispatch, an ISO can achieve efficiencies in system operation similar to what power pools have experienced. Consolidating transmission tariffs provides the ISO an opportunity to employ efficient transmission pricing methods, an issue that has received much attention in the industry recently. Some potential benefits of an ISO include:

- Eliminating discriminatory practices and reducing self-dealing and other market power abuses. A regional ISO will have more information about transmission usage and prices, and it will have more technical expertise to assess regional market power problems than do individual utilities.[33]

[31] Written comments of Professor Paul L. Jaskow, Massachusetts Institute of Technology, submitted to the Federal Energy Regulatory Commission, *Technical Conference Concerning Independent Systems Operators and Reform of Power Pools Under the Federal Power Act* (Washington, DC, January 24, 1996).

[32] Federal Energy Regulatory Commission, *Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act*, 18 CFR Chapter I (October 26, 1994).

[33] Federal Energy Regulatory Commission, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 18 CFR Part 2 (December 18, 1996).

- Developing efficient methods for pricing transmission services, resulting in lower transmission costs to customers. This is possible because an ISO will administer a unified transmission tariff applicable to all transmission facilities under its control instead of having multiple utility transmission tariffs in the region. (Transmission pricing is discussed in depth in the next section of this chapter.)

- Managing and resolving transmission congestion efficiently, using market-oriented approaches. This is possible because the ISO will have operational oversight of a large regional transmission system. (Transmission congestion is also discussed in depth in the next section of this chapter.)

- Simplifying procedures for transmission customers to obtain transmission services through a unified transmission tariff. This is called one-stop shopping for transmission services.

- Providing objective and timely resolutions of disputes among utilities. In a highly competitive power generation sector, this role is important.

The ISO concept is not without criticism. Critics believe that separation of ownership from control is a flawed concept, and that it will not completely eliminate discriminatory practices. By maintaining transmission ownership rights, vertically integrated utilities may still have advantages over non-owners. Critics maintain that a more effective approach would be to create an independent transmission company by physically separating generation and transmission ownership through divestiture.[34] Critics also point out that an ISO will lack incentives to construct needed transmission facilities in the future.

Success of the ISO concept may hinge on overcoming the following related issues:

- The ISO is a nonprofit entity that controls, but does not own, the transmission facilities. As a non-owner, will the ISO employee have incentives to perform effectively? Clearly, the ISO designers need to establish appropriate incentives for management and administration. Organizational performance measurements of some sort are needed as well.

- Will the ISO have sufficient control over transmission facilities to provide fair and equitable access to the transmission system? This requires that the transmission owners transfer to the ISOs all relevant responsibility to control the transmission system, and that the ISOs have adequate authority to exercise their responsibilities. Also, sufficient information to monitor the transmission system must be available to the ISO.

Status of ISO Proposals

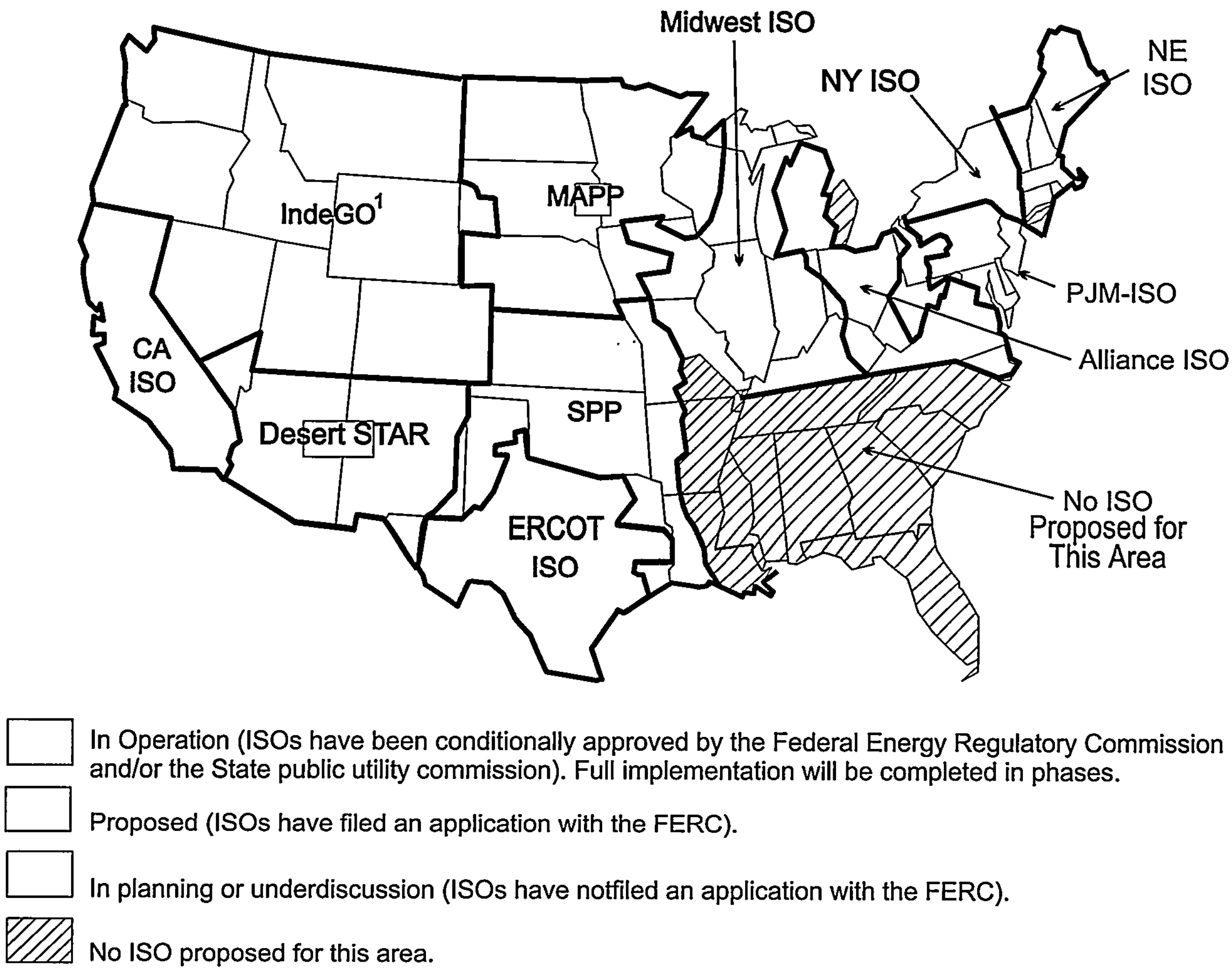
At present, four ISOs are operating and seven ISOs are in different planning stages (Figure 13 and Table 15). With the exception of the Southeast region, ISOs are planned in all regions of the United States, although, in most cases, regional coverage is incomplete. In the Midwest, for example, portions of the transmission grid in Michigan, Indiana, Ohio, Kentucky, and Missouri will be controlled by the ISO, while other sections of the grid in the same States will not. Incomplete regional coverage will limit the gains in efficiency of operation expected from an ISO-administered, region-wide transmission tariff.[35] Following is a summary of the progress of each ISO proposal:

- **California ISO:** In October 1997, the FERC conditionally approved the California ISO and the California Power Exchange (PX). Although the scheduled start was January 1, 1998, a 3-month delay was required to finish debugging the hardware and software that will run the new market structure, and the ISO and PX began operating on March 31, 1998. The ISO controls the transmission grid, and the PX operates a competitive auction for energy. California is one of two regions creating an ISO and an independent PX (New York is the other). California's restructuring team believed that separating the ISO and PX would build confidence in the integrity of the new institutions by eliminating any perception that the ISO favors

[34] This concept refers to a utility divesting ownership of its transmission facilities. California's Public Utility Commissioner Greg Conlon stated this position, noting that the ISO in California was a compromise solution to the State's restructuring initiative. "Fitch Analyst Sees ISOs Playing Brief and Relatively Minor Role," *Electric Power Week* (August 25, 1997), p. 8.

[35] The Clinton Administration's *Comprehensive Electricity Competition Plan* addressed this issue by proposing an amendment to the Federal Power Act to provide FERC with the authority to require utilities to transfer operational control of their transmission facilities to an independent system operator (Washington, DC, March 25, 1998), p. 8.

Figure 13. Independent System Operators in Operation, Proposed, or Under Discussion as of March 31, 1998



[1]As of March 1998, continued development of IndeGO has been postponed, and its future is uncertain.
IndeGO: Independent Grid Operator; MAPP: Mid-Continent Area Power Pool; SPP: Southwest Power Pool; PJM: Pennsylvania, New Jersey, Maryland; ERCOT: Electric Reliability Council of Texas.
Note: ISO control of the transmission grid is incomplete in many of the regions shown on the map. Data are not available to show specific areas covered within regions. For example, the California ISO currently controls approximately 75 percent of the power grid in California.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

one energy supplier over another in dispatching generation and scheduling transmission.[36] Initially, the ISO will control most, but not all, of the transmission facilities in the State. Los Angeles Department of Water & Power, a large public utility owning an estimated 25 percent of the State-wide transmission system, has not joined the ISO, but it is expected to join after resolving some outstanding issues. Full implementation of the California ISO and PX will be accomplished in stages lasting about a year from the start date. During that time, the ISO and PX are required to file quarterly status reports to the FERC. Because of the size, complexity, and newness of this effort, the ISO and PX will conduct a comprehensive review of their activities after the first 3 years of operation.

[36] D.W. Fessler, in *Federal Energy Regulatory Commission Technical Conference Concerning Independent System Operators* (Washington, DC, January 24, 1996).

Table 15. Summary Information on Approved and Planned Independent System Operators as of March 31, 1998

	California ISO	ERCOT Texas ISO	ISO New England	MidWest ISO (MISO)	New York ISO	Pennsylvania, New Jersey, Maryland (PJM)-ISO	DesertStar	Independent Grid Operator (IndeGO)	Midcontinent Area Power Pool (MAPP)	Southwest Power Pool (SPP)	Alliance ISO
Status	Conditionally approved by FERC. Start date March 31, 1998.	Approved by the Texas PUC and operating.	Conditionally approved by FERC. Partially operating.	Submitted FERC filing January 1998. Currently under review.	Submitted FERC filing December 1997. Currently under review.	Conditional approval by FERC. Start date April 1998.	FERC application under development. Expected filing date unknown.	In March 1998, IndeGO officially suspended further development. Its future is uncertain.	FERC application under development. FERC filing in late May 1998.	Under discussion.	Under discussion.
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	Arizona, Nevada, New Mexico, Texas	Northwest Region	Iowa, Kansas, Minnesota, Missouri, Montana, Nebraska, South Dakota, Wisconsin	Louisiana, Arkansas, Oklahoma, Texas, Kansas, Missouri	Michigan, Ohio, Virginia, West Virginia
Number of Transmission Owners	3	16	15	13	8	10	7	Undecided	19	11	3
Type of Organization	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Under development	Under development	Under development
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	Undecided	7 independent members	Under development	Under development	Under development
Control Areas	Single	Multiple	Single	Multiple	Single	Single	Multiple	Multiple	Multiple	Multiple	Multiple
Transmission Facilities Controlled by the ISO	Facilities still undefined. TOs will physically operate.	Not controlled by the ISO.	69 kV and above. TOs physically operate.	60 kV and above. TOs physically operate.	115 kV and above. TOs physically operate.	230 kV and above.	230 kV and above; TOs physically operate.	230 kV and above; TOs physically operate.	Under development.	Under development.	Under development.
Transmission Rights Program	Under development (due 6/30/98)	None	Under development	Undecided	Transmission congestion contracts	Fixed transmission rights	Undecided	Under development	Unknown	Unknown	Unknown

See footnotes at end of table.

Table 15. Summary Information on Approved and Planned Independent System Operators as of March 31, 1998 (Continued)

	California ISO	ERCOT Texas ISO	ISO New England	MidWest ISO (MISO)	New York ISO	Pennsylvania, New Jersey, Maryland (PJM)–ISO	DesertStar	Independent Grid Operator (IndeGO)	Midcontinent Area Power Pool (MAPP)	Southwest Power Pool (SPP)	Alliance ISO
Transmission Congestion Charges	Two active congestion zones. Charges based on adjustment bids submitted by power suppliers.	Under development	Charges based on costs of redispatch, will be paid by all loads on a load ratio share.	Charges based on cost of redispatch, will be spread among all loads.	Based on the difference in locational marginal prices of energy (LMP). Zones represent locations. Customers at the location pay the charges.	Based on the difference in locational marginal prices of energy (LMP). 1600 nodes represent locations. Customers at the location pay the charges.	Under development.	26 congestion zones. Charges based on adjustment bids submitted by power suppliers.	Unknown.	Unknown.	Unknown.
Transmission Access Charges (Method to Meet Revenue Requirements)	Based on area where customer withdraws power from the grid (similar to zone pricing).	ISO does not have a regional transmission tariff.	A five-year phase-in of a regional postage stamp charge.	One charge based on the zone where the customer withdraws power from the grid. Each control area is a zone.	One charge based on the zone where the customer withdraws power from the grid. Seven zones defined.	One charge based on the zone where the customer withdraws power from the grid. Ten zones defined.	Under development.	Based on the zone where the customer withdraws power. 26 zones defined.	Based on megawattmile for coordination transactions.	Based on megawattmile for short-term point-to-point services.	Under development.
Ancillary Services	ISO procures if not provided	ISO coordinates	ISO can provide	ISO will arrange for services	ISO can provide.	ISO provides or coordinates	ISO will provide after phase-in	ISO will provide or coordinate as necessary	Under development	Under development	Under development
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	Under discussion	ISO has primary planning responsibility.	Under discussion	Under discussion	Under discussion
Power Exchange	Separate PX	No PX	ISO and PX combined	No PX	Separate PX	ISO and PX combined	No PX	No PX	Plan to establish power and energy market	Unknown	Unknown

TO = Transmission Owner.

Notes: The information contained in this table summarizes complicated subjects in one or two sentences. A summary is used to present an overview, but it may leave out important details. For more detail, see information sources shown below. Conditional approval means that the ISO needs to resolve or clarify issues raised by the FERC about founding documents, organizations, or other matters.

Sources: **California ISO:** Federal Energy Regulatory Commission, "Order Conditionally Authorizing Limited Operation of an Independent System Operator and Power Exchange," www.caiso.com (October 30, 1997); **ERCOT-Texas ISO:** www.ercot.com (October 30, 1997); **New England ISO:** Federal Energy Regulatory Commission, "Order Conditionally Authorizing Establishment of an Independent System Operator," Docket No. EC97-35-000, www.iso.ne.com (June 25, 1997); **Midwest ISO:** www.midwestiso.com (January 1998); **New York ISO:** "Supplemental Filing to the Comprehensive Proposal to Restructure the New York Wholesale Electric Market," www.nypowerpool.com (December 24, 1997); **PJM-OI:** Federal Energy Regulatory Commission "Order Conditionally Accepting Open Access Transmission Tariff and Power Pool Agreements, Conditionally Authorizing Establishment of an Independent System Operator," www.pjm.com (November 25, 1997); **DesertStar:** www.swrta.com (January 1998); **IndeGO:** www.idahopower.com/ipindego1.htm (March 1998); **MAPP:** www.mapp.com (January 1998); **SPP:** www.spp.com (January 1998); **Alliance ISO:** www.ferc.fed.us/online/rims.htm (March 1998).

- **ERCOT-Texas ISO:** The Electric Reliability Council of Texas (ERCOT) is one of 10 regional reliability council members of the North American Electric Reliability Council (NERC). In late 1996, the Texas Public Utility Commission approved the restructuring of ERCOT into an ISO covering most of the transmission system in Texas. Because most of ERCOT-Texas ISO's power flow is intrastate, it is not under FERC's jurisdiction.

- **NEPOOL and ISO-New England:** The New England Power Pool (NEPOOL) is a tight power pool covering six States in New England. The FERC Order 888 required tight power pools to establish open membership rules and modify any provisions that are discriminatory or preferential. NEPOOL chose to create an ISO to accomplish these objectives, and on June 25, 1997, the FERC conditionally approved transfer of transmission facilities to the ISO-New England. Under NEPOOL's restructuring plan, NEPOOL remains a wholesale power pool in New England with responsibilities for nondiscriminatory operation and implementation of a regional transmission tariff. ISO-New England, under contract to NEPOOL effective July 1997, will administer the transmission tariff and be responsible for system reliability. According to the FERC's order conditionally authorizing ISO-New England, a number of issues regarding the terms and conditions of service under the NEPOOL's transmission tariff remain unresolved, but no date was given for resolution.[37] Also, NEPOOL announced recently a targeted fourth quarter 1998 start of its wholesale electricity spot market.

- **Midwest ISO:** In January 1998, nine utilities filed an application with the FERC to establish an ISO. The ISO, if approved, will cover portions of an eight-State region. Initially, 26 companies were interested in joining the Midwest ISO, but 17 withdrew their support. Eleven of the 17 companies withdrew to explore forming a transmission entity of their own.[38]

- **New York Power Pool/New York ISO:** In January 1997, the New York Power Pool (NYPP), which is a tight power pool consisting of seven transmission-owning utilities, filed with the FERC a restructuring proposal to create an ISO. In December 1997, NYPP then submitted a revised supplemental filing that is currently under review by the FERC. As mentioned previously, NYPP was evaluating the need to create an independent PX. In its December 1997 filing, however, it retained the possibility of a PX but was no longer actively seeking its approval.

- **PJM-ISO:** Pennsylvania, New Jersey, and Maryland is a tight power pool covering portions of five States in the mid-Atlantic region and the District of Columbia. In November 1997, the FERC conditionally approved PJM's restructuring plan to create an ISO effective January 1, 1998. The PJM-ISO started operating on April 1, 1998.

- **DesertStar:** DesertStar recently completed Phase 1 of a study to determine the feasibility of creating an ISO in a four-State region in the southwestern United States. Phase 2 will cover a number of remaining issues, such as DesertStar's role in regional planning, and refinement of the transmission facilities controlled by DesertStar. Working groups have prepared preliminary documents to establish the ISO that, when completed, will comprise their application to the FERC. No specific schedule was given for completing the documents.

- **Independent Grid Operator (IndeGO):** In July 1996, seven investor-owned utilities (IOUs) in the Pacific Northwest agreed to create an independent grid operator to control portions of the transmission grid in 11 States located in the Midwest and Northwest regions. The number of IndeGO signatories eventually grew to 21. Recently, however, a number of these signatories withdrew their support for IndeGO because of problems with cost shifting among participants and the uncertainty of the Federal Bonneville Power Administration's (BPA) participation. BPA controls more than 50 percent of the region's transmission grid. In March 1998, the original seven IOUs withdrew their support for IndeGO and suspended further efforts to develop the ISO. They announced that the ISO may be revived when the BPA and State restructuring issues are clarified, but they gave no timetable. Because of this development, IndeGO's future is uncertain.

- **Mid-Continent Area Power Pool (MAPP):** The Mid-Continent Area Power Pool has been working on an ISO proposal since September 1996. The

[37] Federal Energy Regulatory Commission, *Order Conditionally Authorizing Establishment of an Independent System Operator and Disposition of Control Over Jurisdictional Facilities*, Docket No. EC97-35-000 (June 25, 1997).

[38] "Midwest ISO Cratered by Breakaway Group; Regional Picture Now Unclear," *Electric Utility Week* (December 15, 1997), p. 1.

expected completion date is still unknown. In July 1997, MAPP filed a region-wide transmission tariff for coordination transactions. Coordination transactions are wholesale transactions between members using existing generation and transmission facilities. This regional transmission tariff is an important first step toward creating an ISO.

- **Southwest Power Pool (SPP):** Southwest Power Pool is in the early stages of designing an ISO. In December 1997, SPP filed with the FERC a region-wide open access transmission tariff, which supplants, in part, the transmission owners' current tariffs. Similar to the MAPP's tariff, this is an important step toward creating an ISO. The effective data for the tariff is April 1, 1998; however, no date has been scheduled for the ISO filing.

- **Alliance ISO:** The Alliance ISO is the most recent announcement of plans to create an ISO. Currently, the Alliance ISO consists of three investor-owned utilities covering portions of the transmission grid in five States. In March 1998, members of the ISO completed a report outlining the main features of the ISO. Additional work is ongoing to develop detailed specifications for the ISO.

Responsibilities of ISOs

The responsibilities of ISOs are very broad, going far beyond the role of ensuring comparable and open access to the regional transmission grid. In Order 888, FERC provided a core set of 11 generic responsibilities or principles for ISOs that propose to operate as a control area (see box).[39] For example, principle 4 requires the ISO to ensure short-term reliability of the transmission system, and principle 5 requires that the ISO have control over the operation of the interconnected transmission facilities. To obtain the FERC's approval, the ISO must comply with these generic principles, although the ISO has latitude in the detailed implementation.

ISO functions can be classified broadly under two categories: the facilitation of a wholesale power market, and the control of the transmission grid and related facilities (Figure 14). The relative importance of the

FERC ORDER 888
PRINCIPLES FOR INDEPENDENT SYSTEM OPERATORS (ISOs)

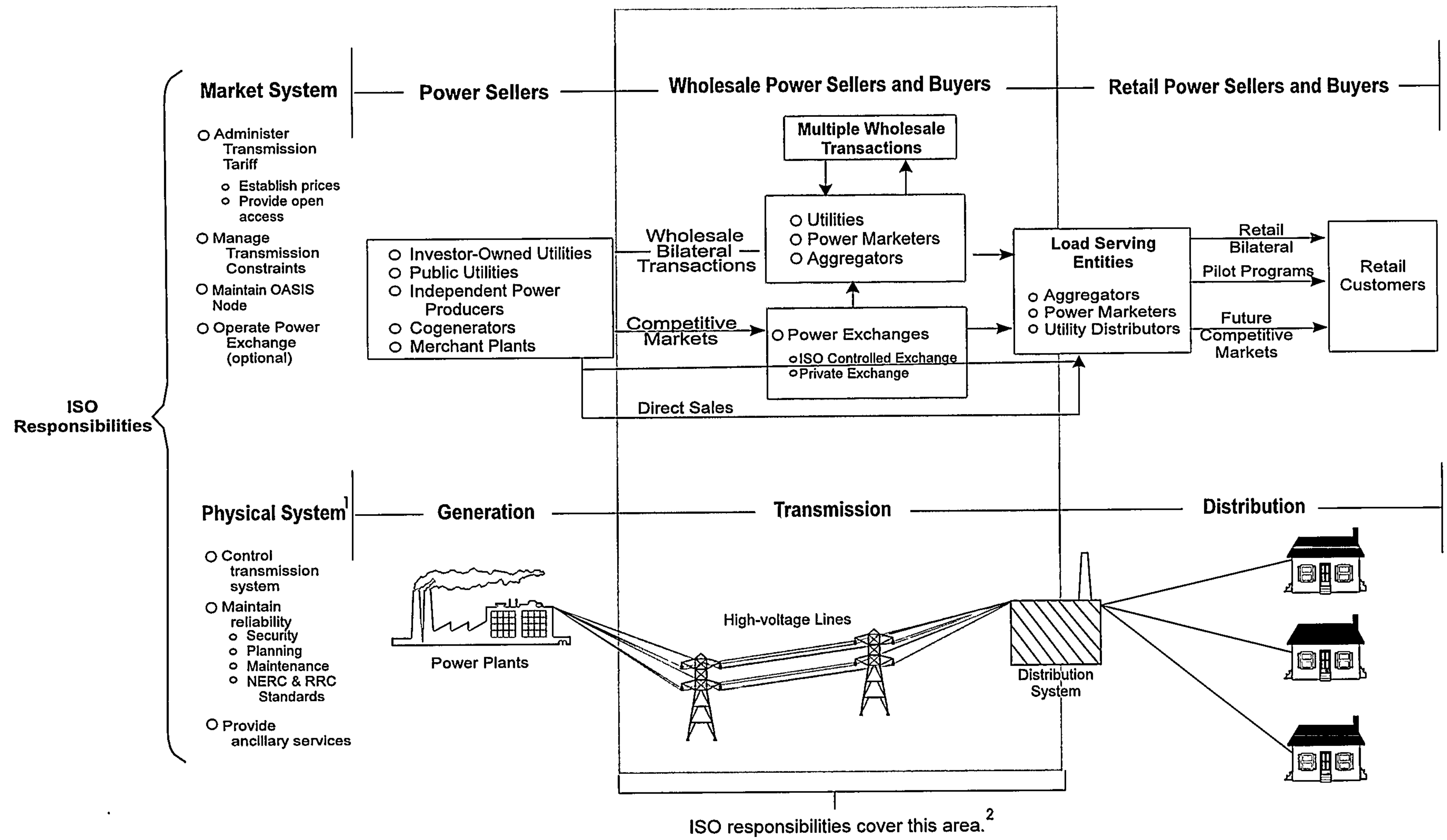
- The ISO's governance should be structured in a fair and nondiscriminatory manner.
- An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict-of-interest standards.
- An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users.
- An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role should be well defined and comply with applicable standards set by the North American Electric Reliability Council and the regional reliability council.
- An ISO should have control over the operation of interconnected transmission facilities within its region.
- An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.
- An ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.
- An ISO's transmission and ancillary services pricing policies should promote the efficient use of, and investment in, generation, transmission, and consumption. An ISO or an Regional Transmission Group (RTG) of which an ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.
- An ISO should make transmission system information publicly available on a timely basis via an Open Access Same Time Information System (OASIS).
- An ISO should develop mechanisms to coordinate with neighboring control areas.
- An ISO should establish an Alternative Dispute Resolution (ADR) process to resolve disputes in the first instance.

Note: Principles are applicable only to ISOs that would be control area operators, including any ISO established in the restructuring of power pools.

Source: Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utilities*, Order No. 888 (Washington, DC, April 24, 1996).

[39] Additional discussion of an ISO's responsibilities is contained in: Secretary of Energy Advisory Board Task Force on Electric System Reliability, *The Characteristics of the Independent System Operator* (Washington, DC, March 1998).

Figure 14. Overview of an Independent System Operator's Responsibilities



[1] In some instances, transmission owners, not ISO employees, will physically operate portions of the transmission system. Details vary among ISO proposals. In addition, the type of facilities controlled by an ISO vary by region.

[2]An ISO also affects unit power generation through energy balancing, management of congestion, and responding to emergency conditions.

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

functions within these two categories, and the details of how they are performed, vary among ISOs. A review of current ISO plans suggests the following general observations:

- **Control of the Transmission System:** The type of transmission lines under ISO control will vary among ISOs. The Midwest ISO proposes to take operational control of transmission lines 60 kilovolts and above, while most other ISOs will control lines 230 kilovolts and above. Other facilities needed to operate the system, to perform control area functions, or to perform functions critical to security will be transferred to the ISO as well. The transmission owner will maintain control of all transmission facilities not transferred to the ISO. Usually, the specific facilities are named in a formal agreement between the ISO and the transmission owners. Sometimes the distinction between ISO-controlled facilities and facilities not controlled by the ISO may be unclear to transmission customers. This apparently is a problem within the PJM-ISO transmission grid. PJM-ISO will be required to maintain a public list identifying the entity that has operational control of transmission facilities and the effective date of control.

- **Maintain System Reliability:** ISOs are required to comply with the standards of the North American Electric Reliability Council (NERC) and Regional Reliability Council (RRC). These standards apply to control areas, the primary unit responsible for operating reliability of the system. Some ISOs will function as a single control area, while others will maintain multiple control areas with the ISO having oversight responsibility. Most but not all ISOs will serve as NERC security coordinators, providing security assessments and coordinating emergency operations for a group of control areas.

- **Provide Ancillary Services:** The FERC specified two ancillary services that transmission providers are required to provide their transmission customers: system control and voltage control. ISOs operating as a single control area will provide these services. FERC also specified four additional services that the ISO must provide to transmission customers serving load in the control area: regulation, spinning reserve, supplemental operating reserve, and energy imbalance. The customers may obtain these four services from the ISO or from another source, or provide it themselves. Some ISOs are proposing to operate competitive markets for ancillary services. For example, the California ISO plans to operate day-ahead and hourly auctions for regulation, spinning reserves, non-spinning reserves, and replacement reserves when these services are not self-provided.

- **Administer Transmission Tariff:** All ISOs, except ERCOT, will administer a system-wide transmission tariff. The transmission tariff is the instrument providing open access to the grid. It specifies the terms and conditions of transmission services, and prices for these services. As a system-wide tariff, it provides one-stop shopping for transmission access and charges, and it eliminates the pancaking effect of transmission charges for multiple tariffs.

- **Manage Transmission Constraints:** ISOs have the responsibility to identify and relieve congestion on the transmission grid, which can be accomplished by dispatching generators to produce electricity that bypasses the congested lines. This is called out-of-merit dispatch or redispatch of generation. Generation redispatch increases transmission costs. The contentious issue is who pays for the additional costs. Three ISOs—California ISO, New York ISO, and PJM-ISO—have proposed innovative market-oriented approaches to calculate congestion costs and allocate these costs to transmission customers.

- **Provide Transmission System Information:** FERC Order 889 requires transmission providers to provide timely information on transmission capacity, ancillary services, and prices to transmission customers on the Open Access Same-Time Information System (OASIS). Most of the ISOs have established an OASIS node where information is displayed about the transmission grids and services in their regions. California has created a separate system for customers but it is required to comply with the OASIS requirement in the future.

- **Operate a Power Exchange (optional):** A power exchange (PX) is a centralized market where energy suppliers submit bids to sell electricity and energy customers make offers to buy energy. Four regions plan to develop wholesale PXs. In California and New York, the PX will be separate and independent from the ISO. California's PX started in March 1998, while New York's PX is still in planning. PJM-ISO and ISO-New England plan to combine a PX with the ISO function. PJM-ISO's PX began operating April 1998, and ISO-New England's PX is in the planning stage.

Need for Independent Governance of ISOs

To be a credible administrator of fair and nondiscriminatory transmission access, the ISO's governing structure must be independent of any individual market participant or class of participants, and the governing rules should prevent control by any class of participants.[40] Also, employees of the ISO must be financially independent of market participants. The FERC's ISO principles 1 and 2, which are referred to as the "bedrock"[41] upon which an ISO must be built, emphasize these points.

The composition and structure of the Board of Directors is perhaps the key element for ensuring independence of the ISO. The board will have ultimate approval authority over the organization's policy and operating procedures. To establish an independent board, ISOs in the United States have chosen to use two models. One model is the multi-class stakeholder board, where most or all classes of users are represented on the board. Typical stakeholder classes are utilities owning transmission facilities, utilities not owning transmission facilities, independent power producers, power marketers, and end users. The board's independence is maintained by balancing the number of directors representing each class of market participants. A multi-class stakeholder approach, which is being used in California's ISO and Power Exchange, is perceived as "fair" because it gives stakeholders a voice in governance. Also, it ensures direct participation by market participants with experience in power transmission systems. On the other hand, with many different interest groups, the board's voting rules are important. If the voting rules are flawed, the board may fail to achieve independence, or it may be difficult to reach consensus on important issues because of competing interest groups.

The other model, which most ISOs have chosen to use, is the non-stakeholder board, sometimes referred to as an independent board. This model achieves independence by prohibiting board members from having financial interest in any of the market participants. If, when selected for the board, an individual has financial interests in a market participant, the ISO's code-of-conduct will specify that the individual must divest interest by a certain time. The principal problem with this model is that the board may become isolated from the organization because board members have no direct interest in the industry.

Some of the ISOs are designing a two-tier governance structure that combines the strengths of both models to provide an independent board with a working knowledge of the transmission system. Under this structure, a multi-class stakeholder group reports to an independent non-stakeholder board. The PJM-ISO designed this type of structure, with a members committee consisting of five stakeholder classes reporting to an independent board.

Creating More Efficient Transmission Pricing Through an ISO

Transmission costs represent about 2 percent of major investor-owned utilities' operating expenses, which is relatively small compared to power production expenses (Figure 15).[42] The question arises, if transmission prices are relatively small, why are they important? Transmission prices are important because they provide price signals that can create efficiencies in the power generation market. For example, transmission prices, if correctly calculated, send signals to add transmission capacity, or generation, or where to locate future load. Adding transmission capacity to relieve transmission constraints can allow high-cost generation to be replaced by less expensive generation, which results in savings to consumers. Also, a well-structured transmission tariff can eliminate "pancaked" prices, lower transmission costs, and open a region to increased competition. (Pancaked prices are discussed later in this chapter.)

The FERC, through its transmission pricing policy and approval authority, recognizes the key role of transmission prices in a competitive industry (see box). The FERC's pricing objectives indicate that while meeting revenue requirements is an important objective, transmission prices should also promote economic efficiency. Most of the ISOs have designed transmission pricing methods that are more efficient than those used in the past.[43]

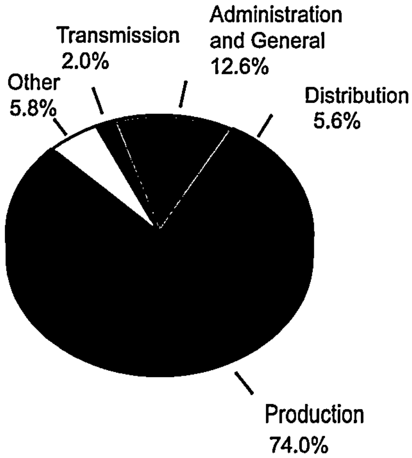
[40] Many of the governance concepts in this section are discussed in more detail in James Barker et al., *Governance and Regulation of Power Pools and System Operators, An International Comparison*, World Bank Technical Paper No. 382 (Washington, DC, September 1997).

[41] Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities*, Order No. 888-A, 18 CFR 35, p. 211.

[42] These costs do not include the cost of ancillary services, which are reported as production expenses.

[43] Federal Energy Regulatory Commission, *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, 18 CFR PART 2.22.

Figure 15. Distribution of Operation and Maintenance Expenses for Investor-Owned Utilities, 1996



Source: Energy Information Administration, *Financial Statistics of Major Investor-Owned Utilities 1996*, DOE/EIA-0437(96/1) (Washington, DC, December 1997).

FERC's Principles for Transmission Pricing

- Transmission pricing must meet the traditional revenue requirements of the transmission owners.
- Transmission pricing must reflect comparability. Comparability means that a transmission owner should charge itself on the same basis that it charges others for the same service.
- Transmission pricing should promote economic efficiency.
- Transmission pricing should promote fairness.
- Transmission pricing should be practical.

Source: Federal Energy Regulatory Commission, *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, 18 CFR PART 2.22.

Transmission Pricing To Meet Revenue Requirements: Utilities have historically used the "contract path" concept for transactions. Under the contract path concept, the transacting parties assume that power flows over a predefined path, and that transmission prices are based on the predefined path. This technique is straightforward and easy to administer. In reality, however, power flows are rarely confined to a predefined contract path; instead, according to physical laws, power flows in a network over multiple parallel paths that may be owned by several utilities not on the contract path. Under the contract path, therefore, a transmission owner may not be reimbursed for use of its facilities (Figure 16).

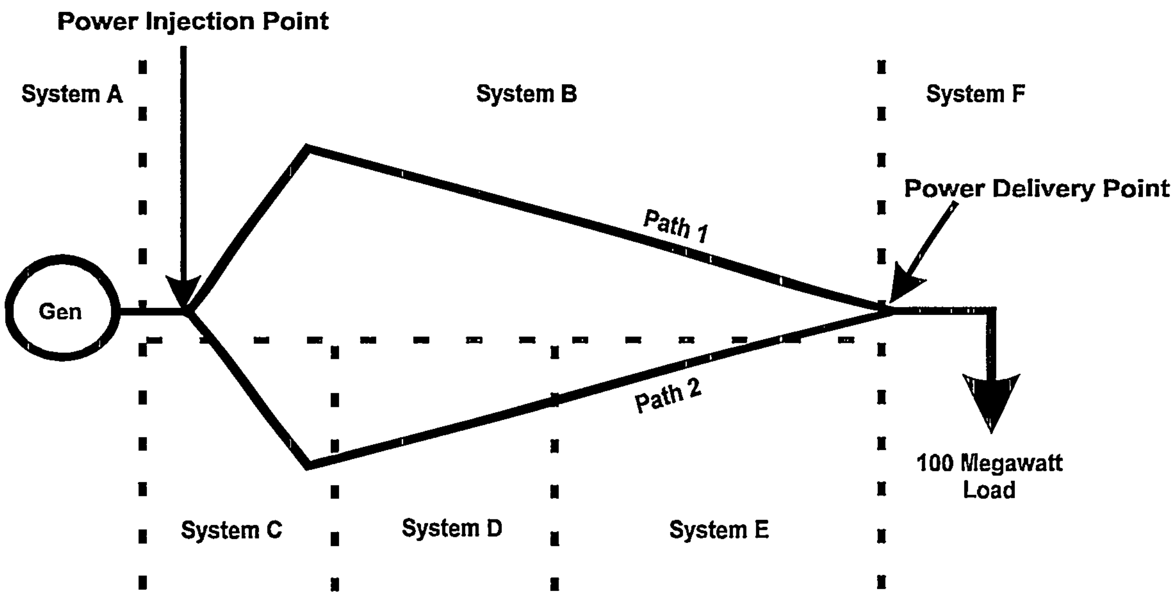
The contract path method fails to deal with parallel path flows (also called loop flows), and it facilitates the pancaking of transmission rates as power moves across any region with two or more transmission owners (Figure 17). Each time the contract path crosses a boundary defining transmission ownership, additional transmission charges are added to the transaction. This pancake effect can double or triple the price of the transaction, depending on the number of systems it crosses.

To eliminate pancake transmission rates, most ISOs have proposed zone pricing. With zone pricing, the transmission grid under ISO control is divided into zones, and the transmission customer pays one rate based on the zone where the energy is withdrawn, regardless of how many other zones are crossed in the ISO's region. For example, PJM-ISO has defined 10 zones corresponding to the service areas of the transmission owners in its region. The customer pays the rate of the zone where the load is located. The rates for a particular zone are based on the revenue requirements of the transmission owners in the zone.

Zone rates are considered, in some instances, an interim method. Ultimately, the ISOs may implement a system-wide uniform rate without zones, which was recommended by the FERC. A system-wide transmission rate would be based on the average revenue requirements of transmission owners across the entire ISO region. One problem with this approach, however, is that an average uniform price may result in "cost shifting" when the revenue requirements of high- and low-cost transmission owners are averaged. Some cost shifting may be unavoidable if a uniform system-wide rate is the ultimate objective. PJM-ISO was ordered by the FERC to file a uniform system-wide rate proposal by July 2002. The FERC's guidance was that PJM-ISO should eventually move to pricing based on electrical characteristics and power flows instead of corporate boundaries, although no schedule was given to complete the transition. Zone pricing or a system-wide uniform rate does not account for or resolve parallel power flows.

Two regions planning to create ISOs—MAPP and SPP—have proposed using a megawatt-mile methodology for transmission pricing. This approach is a distance-based method that takes into account parallel power flows. Using power flow modeling techniques and appropriate software, actual energy transactions are modeled to identify the power flow over all paths from the generating source to the load. Transmission line charges will be calculated for each line where power flowed, based on the results of the model. This approach eliminates the problem using the contract path method

Figure 16. Example of the Effect of Parallel Path Flows on the Contract Path Pricing Method



In the example, two different transmission paths of similar length, with the same injection and delivery points, impact a different number of systems. A customer in System F purchases power from a generator in System A. The transmission system contains two paths (1 and 2). Path 1 impacts only systems A, B, and F, while Path 2 impacts all of the systems on the diagram. Using fully pancaked contract-path pricing, Path 2 would cost more than Path 1 for what may be considered a similar use of the transmission system because the transaction accesses multiple systems. Under contract path pricing, Path 1 would be the least-cost contract path. If this transaction took place, power would flow through both paths based on relative impedance of the electric transmission lines. It is possible that most power would flow along Path 2, yet the transmission owners along this path would not be compensated for the use of their facilities.

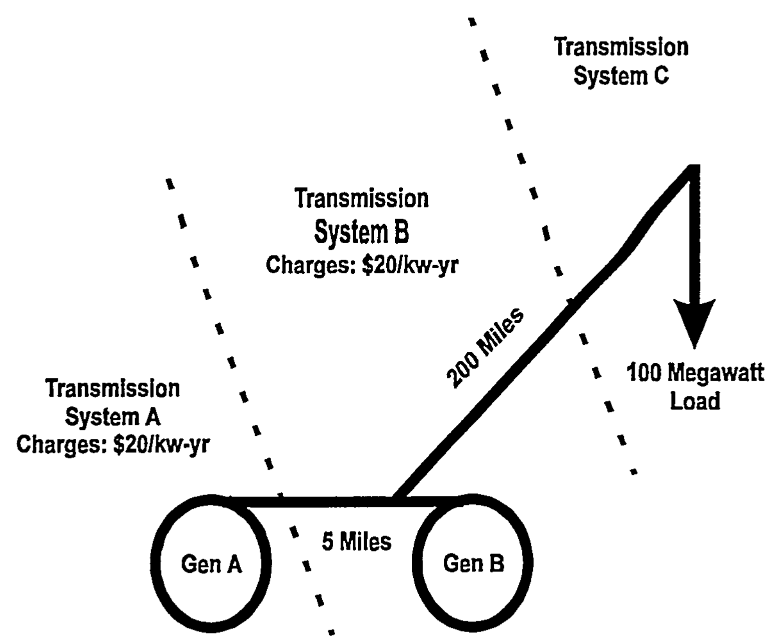
Source: Adapted from M. Cannella et al., "Beyond the Contract Path: A Realistic Approach to Transmission Pricing," *The Electricity Journal* (November 1996).

where transmission owners are not reimbursed for using their facilities. However, critics claim that this approach does not correctly measure usage because it gives no credit for counterflows on transmission lines. The method is also administratively more complicated than other methods, because every change in transmission lines or transmission equipment requires recalculation of the flow simulation. Some market participants prefer the simplicity of a system-wide uniform transmission price.

Pricing Transmission Congestion: Congestion in the transmission system occurs when a transmission line reaches its transmitting capacity, limiting the system operator from dispatching additional power from a specific generator. Congestion may be caused by generation or power grid outages, increases in energy demand, or loop flow problems. When congestion occurs, the transmission system operator may have a number of options it can use to solve the problem. For example, it can curtail power from certain generators, or it can dispatch another generator outside the congested area to supply power. Curtailment of power from a generator may be referred to as redispatch, and the use of another generator to supply power is called out-of-merit dispatch.

Whatever option the operator uses to relieve congestion has costs, which are called congestion costs. They consist of the following items: the increase in operating costs from dispatching units out-of-merit, and savings or profits forgone when a transmission customer cannot use the system because of constraints. The difference in operating costs between the high-cost generator, which was dispatched out-of-merit, and the lower cost generator equals the transmission congestion cost. It can be significant, depending on the relative operating costs of the generators. Congestion costs are measured by the difference in generation costs between locations.

Figure 17. Example of the Pancake Effect of the Contract Path Pricing Method



Pancaking rates for transactions that cross multiple systems compounds the inaccuracies associated with the contract path method of allocation. Each time the contract path crosses a boundary defining transmission ownership, the transmission customer pays an additional transmission access charge. This occurs without regard to the actual system use.

The figure above shows the wheeling associated with a 100-megawatt sale to System C. Generators in System A and System B are located 5 miles apart and both want to bid on the sale. Under the contract-path method, generator A would pay double the wheeling charge for essentially the same use of the system. This is because generator A pays a charge for using systems A and B, while generator B pays for using system B only.

Source: Adapted from M. Cannella et al., "Beyond the Contract Path: A Realistic Approach to Transmission Pricing," *The Electricity Journal* (November 1996).

In the past, congestion costs were either unaccounted for or bundled into the transmission rate and therefore hidden. This approach has shortcomings: it provides no price signal for efficient allocation of transmission resources, it allocates congestion costs to transmission customers who are not causing the congestion, and in the short term, it provides no economically efficient way for relieving congestion.

All the ISOs are developing methods to measure congestion costs and charge their transmission customers for these costs. Three methods for computing congestion charges have been proposed. A basic overview of these methods follows:

- The PJM and New York ISOs are using a technique called location-based marginal pricing (LBMP).[44] LBMP is based on the cost of supplying energy to the next increment of load at a specific location on the transmission grid. LBMP serves two purposes: it determines the price that buyers will pay for energy in a competitive market at specific locations, and it measurers congestion costs by taking the difference in the LBMP between two locations (see box on page 44). PJM-ISO will compute LBMPs at 1,600 locations in its region. Calculation of the LBMP is based on bids into the power exchange. PJM-ISO will operate a power exchange, and the New York ISO plans to create an

[44] Many articles on location-based marginal pricing are available in trade journals. The *Electricity Journal* for the years 1996-1997 has some informative articles on LBMP. Also, a good explanation of LBMP can be found in the Affidavit of Susan Pope to the FERC, *On Congestion Pricing Under the Proposal To Restructure the New York State Electricity Market*, available from the New York Power Pool's web site, www.nypowerpool.com/iso/dec97/VOL_II.PDF.

Example of Congestion Charges Computed by the PJM-ISO and New York ISO

If an energy supplier owns 100 megawatts of generation at point A and needs to serve 100 megawatts of load at point B, it can either:

- Sell 100 megawatts at A and purchase 100 megawatts at B through the ISO spot market, or
- Schedule a 100-megawatt bilateral trade from A to B and pay the congestion charge, if any.

If the LBMP at A is $20/megawatthour and the LBMP at B is $30/megawatthour, then:

- The "spot price" settlement is 100 x $20 = $2,000 minus 100 x $30 = $3,000, for a net "congestion cost" of $1,000 per hour, or
- The bilateral settlement is 100 x ($30 - $20) = $1,000 per hour congestion charge.

Source: S. Pope and J. Chandley, "Locational Marginal Cost Pricing Theory and Calculation," *Conference on Congestion Pricing and Tariffs* (January 23, 1998).

independent power exchange although as noted previously, New York's latest filing did not emphasize the PX.

- The California ISO has taken a different approach. The California ISO divided its region into two active and two inactive congestion zones. Transmission constraints are small within the boundaries of each zone but severe between zones, limiting energy transfer from one zone to another. The California ISO will impose usage charges on all transmission customers who use the interface connections between zones. These charges will be determined from bids voluntarily submitted by scheduling coordinators to adjust (i.e., decrease or increase) power generation.[45] Adjustment bids reflect a scheduling coordinator's willingness to increase or decrease power generation at a specified cost.

- ISO-New England has proposed a more straightforward approach to managing transmission congestion. Congestion charges will be based on the costs of out-of-merit dispatch. These costs will then be allocated to each load on the transmission system on the basis of its load ratio share (i.e., individual load expressed as a percent of total load). This method is less sophisticated than the methods discussed above, but ISO-New England does not have a significant transmission congestion problem, and perhaps a more straightforward approach is justified.

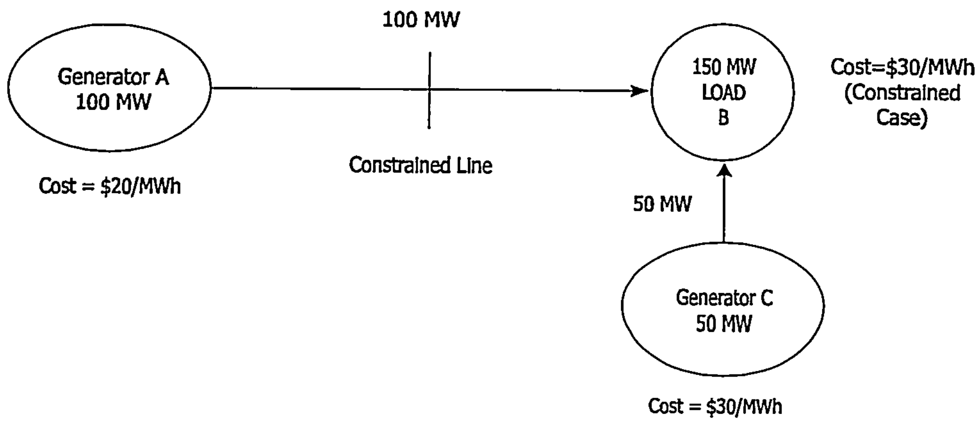
Transmission Access Rights: The term "transmission access rights" (also referred to as transmission capacity reservations) refer to the right to use transmission capacity. They represent a claim on the physical use of the transmission system. Increased competition in the industry and the implementation of open transmission access require that rights and protocols for using the transmission grid be well defined. Most industry observers agree that tradeable transmission rights go hand-in-hand with open transmission access and the innovations now taking place in transmission pricing. With tradeable transmission rights, a utility considering expansion of the transmission system might be able to purchase existing transmission rights more cheaply than expanding the system, thereby avoiding unneeded investment. Efficient transmission usage can be facilitated when transmission customers holding capacity reservations are willing to trade their reservations to those who value them more. Finally, in a highly competitive environment, transmission capacity rights provide transmission price certainty to holders of those rights.

The PJM and New York ISOs have developed an innovative program based on the concept of "financial rights." Financial rights can be equivalent to physical rights, but with financial rights, trading is easier and less costly because usage of the transmission system need not be tied to ownership rights. A financial right, defined for two points on the transmission grid, entitles the holder to receive payment when the cost of energy between the two points varies (Figure 18). The initial allocation of financial rights will go to transmission customers with existing transmission contracts and to transmission owners on the basis of their need to serve native load. The ISO will also sell financial rights in a centralized auction. Holders of these rights are free to trade their rights.

This brief overview of transmission rights shows how they can be used in a competitive electricity industry;

[45] The California restructuring plan creates scheduling coordinators whose purpose is to prepare schedules that match generation with demand for their customers. The California Power Exchange is one of the scheduling coordinators. The scheduling coordinators submit their proposed schedules for power to the California ISO. The ISO has the job of reconciling the requests of the various scheduling coordinators and dispatching the generators.

Figure 18. Example of Congestion Charges and Fixed Transmission Rights



1. Load B has a peak load of 150 megawatts. It has contracted 100 megawatts from Generator A and 50 megawatts from Generator C. Load B is responsible for paying for the cost of transmission.

2. When Load B reaches its peak load of 150 megawatts, the line from Generator A to Load B becomes constrained. The extra load cannot be supplied by Generator A, so Generator C is used to meet the peak load. The highest cost generator running (Generator C) sets the price of $30/per megawatthour at Load B.

3. To hedge against fluctuations in transmission cost caused by congestion, Load B purchases a fixed transmission right (FTR) for 100 megawatts for the line from Generator A to Load B.

4. Calculation of Congestion Charges.
   Congestion Charge = 100 MWh x ($30 - $20) = $1,000 per hour.
   Congestion Charge = 50 MWh x ($30 - $30) = 0.

5. Because Load B holds fixed transmission rights for 100 megawatts on the line from Generator A to Load B, Load B will be credited for the congestion charge at settlement.
   Congestion Credit = 100 MW x ($30 - $20) = $1,000 per hour.

MW=Megawatt.
MWh=Megawatthour.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

however, the concept of tradeable transmission rights has never been tested in the United States, and its effectiveness as a financial tool in the industry remains to be seen. The California ISO is currently designing a transmission rights program, and other ISOs may follow if the concept proves feasible.

Power Exchanges and the ISO

Most financial energy transactions in the industry today are bilateral. Buyers and sellers contract individually for power under prices, terms, and conditions they agree upon. The time frame of the transaction can be short- or long-term. Although bilateral trading is the primary trading method, over the past few years the power industry has seen the emergence of power exchanges, a new approach to selling energy. A PX, also called a spot price pool, is a trading center where utilities, power marketers, and other electricity suppliers submit price and quantity bids to sell energy or services, and potential customers submit offers to purchase energy or services. A few commercial exchanges are already operating: California-Oregon Border; Palo Verde, and a few other locations.[46] Abroad, England and Wales,

[46] Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), p. 98.

Norway, Chile, and portions of Australia use power exchanges to trade electrical energy. Now, some regions with ISOs under development are also planning to establish nonprofit power exchanges (California ISO, ISO-New England, PJM-ISO, and maybe the NY-ISO).

Some industry observers have criticized the idea of an energy power exchange. They say that a centralized energy market is unnecessary and that, with an increasing number of market participants, bilateral markets will achieve the same efficiencies expected of a power exchange. On the other hand, proponents of power exchanges claim the following advantages:

- A power exchange produces efficient use of generation resources by selecting energy supply bids on a least-cost basis.

- A power exchange creates a perception of fairness because it creates a single energy price visible to all participants in the wholesale market.

- An independently operated power exchange provides an assurance that all similar users will have access to power at the same price, and that large firms will not be able to exercise market power.

Both bilateral and power exchange energy markets have merit. Interestingly enough, none of the regional energy markets now being proposed will rely strictly on one approach or the other. Those regions planning power exchanges will also maintain active bilateral trading markets. In the United States, bilateral transactions will likely remain the dominant form of energy trading.

Some ISO designs now being proposed have the power exchange directly under ISO control, while other proposals create an independent power exchange. This issue has also been debated extensively throughout the industry.[47] Some say a power exchange controlled by an ISO would have a competitive advantage over other electricity trading markets in the region because, as the regional transmission system operator, it would have information about the transmission system that would not be available to its competitors. On the other hand, proponents of an ISO-controlled power exchange claim that the ISO will operate the market only and will not trade on its own account or make a profit and, therefore, will not be competing against other energy markets. Further, because of the need for energy balancing and other complexities of operating a transmission system, close coordination between the system operator and the power exchange is required. A power exchange directly under the ISO's control is an efficient way to achieve close coordination.

The California PX will be independent of its ISO, while PJM-ISO will operate its PX within the same organization. New York is seeking eventually to create a PX independent from the ISO. With different regions using different approaches, it will be interesting to see which approach produces the most favorable results.

Monitoring Wholesale Power Markets Through an ISO

With new wholesale energy markets being started, regulators and others have raised concerns about the potential for market power or market manipulation by participants. (Market power refers to the ability of a supplier to profitably raise and maintain prices above competitive levels.) One example would be an owner of a must-run unit selling energy at prices above competitive price levels. Must-run generators, because of their location, must be dispatched during certain hours for reliability purposes, which places the units in a favorable position. ISOs specify must-run units in advance of when they are needed.

Market manipulation or abuses can take many forms. For example, a market participant may take unfair advantage of the rules, procedures, or conditions of the market. This may include a power generator, who is aware of a transmission constraint, taking advantage of the constraint by raising prices above those normally charged, or taking advantage of other conditions that affect the availability of transmission and generation capacity, such as generator or transmission outages.

The FERC requires an ISO to monitor its energy market for manipulation or abuses by the participants. This requirement covers both the power exchange (auction-based) market and bilateral transactions in the region. An ISO will prepare a market surveillance plan specifying the scope of its surveillance activities, the data and metrics used to flag potential problems, and remedial actions to eliminate the problems. A compliance staff will implement the ISO's surveillance plan.

[47] The *Wall Street Journal* carried a series of articles and letters to the editor covering this subject: R. Blohm, "Don't Give Utilities a Monopoly on Power" (March 11, 1997); W. Hogan, G. Weil, "Letters to the Editor—A Stock Market for Electricity" (April 2, 1997); R. Blohm, S. Oren, "Letters to the Editor—The Case Against Centralized Electricity" (April 21, 1997).

The ISO's authority to take corrective actions when market abuses are identified depends on the nature of the abuse. Clearly, if a market participant is taking advantage of an ISO's rule or procedure, the ISO will have the authority, subject to the FERC's approval, to change its rules. Violations of the FERC's regulatory policies or of the antitrust laws will be referred to the appropriate agency for action.[48] With an increase in the number of players in the industry, and the newness of the market, surveillance is an important activity to ensure that the market functions properly.

Ensuring System Reliability Through an ISO[49]

In accordance with FERC's ISO principle 4, all ISOs will ensure short-term reliability of grid operation using NERC operating policies and the applicable Regional Reliability Council (RRC) standards. All ISOs that have submitted applications to the FERC have indicated that they will comply with these policies and standards, although compliance is voluntary. The New York ISO has taken its responsibility one step further by establishing a new entity, the New York State Reliability Council (NYSRC). The New York ISO will follow the NYSRC reliability standards, which in turn will follow the NERC and RRC standards. The creation of a State reliability council in New York reflects a concern by the transmission owners that they, rather than the ISO, will be held responsible for maintaining reliability. The NYSRC will apply close oversight of the ISO. New York is the only State with plans to propose its own reliability council.

Compliance with the NERC operating policies has two implications for the ISO. First, because NERC places operating responsibility for reliability with the control area operators (see box), the ISO must direct a control area or become one. The California ISO and each of the three tight power pools that are restructuring into an ISO will operate as one control area. The other ISOs will have multiple control areas within their regions and will provide directives to the control areas.

Second, NERC has created security coordinators that coordinate, oversee, and enforce regional and subregional security processes affecting the bulk electric system.[50] These security coordinators have real-time data to allow them to monitor the grid and to take appropriate action for reliability purposes. Currently, 22 security coordinators cover the four Interconnections in North America (three in the United States and one in Canada). Most ISOs will assume the security coordinator's role (Figure 19). In a few instances (ERCOT, for example), the ISO will not be the security coordinator, and the existing control areas will continue this role.

Maintaining a reliable power system is an important responsibility of an ISO. Increases in the number of wholesale transactions and the number of market participants make operating the transmission grid more complex and maintaining a reliable system more difficult. The competitive dynamics among a much larger universe of players are not at all conducive to a system of voluntary compliance. A fundamental challenge to the industry is the expected decline in voluntary compliance

Introduction to NERC's Operating Policies

NERC operating policies place the responsibility for operating reliably primarily on the Control Areas that operate within the four Interconnections of the United States and Canada and Northern Baja California Norte, Mexico.

NERC recognizes that in the open access transmission environment, Control Area officials are assigning some of their responsibilities, especially for transmission security, to other entities. These entities include independent system operators and security coordinators. The Control Area officials who assign responsibilities to other entities must ensure, through agreements or otherwise, that those entities comply with the NERC operating policies.

Purchasing and selling entities also are responsible for fulfilling their informational and procedural obligations, and for keeping records that document their compliance.

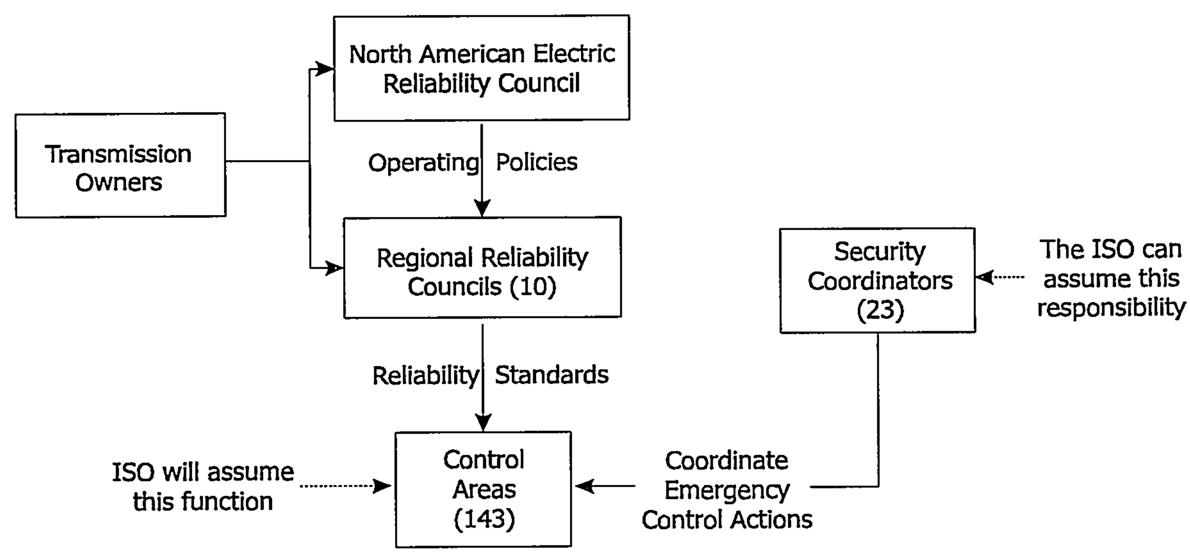
Source: North American Electric Reliability Council, "Introduction to the Operating Policies" (July 8, 1997).

[48] The Clinton Administration's *Comprehensive Electricity Competition Plan* proposes to amend the Federal Power Act to give the FERC the authority to remedy concentrations of market power in the wholesale market, including the authority to order divestiture of assets (Washington, DC, March 25, 1998), p. 7.

[49] A recent report prepared by ICF Resources, Inc., for the Office of Economic, Electricity and Natural Gas Policy, U.S. Department of Energy, contains a thorough discussion of issues associated with ISOs and system reliability. U.S. Department of Energy, *Independent Transmission System Operators and Their Role in Maintaining Reliability in a Restructured Electric Power Industry*, DOE/PO/791010 (Washington, DC, December 1997).

[50] North American Electric Reliability Council, Electric Reliability Panel, *Reliable Power: Renewing the North American Electric Reliability Oversight System* (December 1997).

Figure 19. Organizational Structure for Electric System Reliability



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

with reliability standards.[51] To meet the challenge, some industry leaders are recommending an enforcement authority. The Clinton Administration's recent electricity competition plan proposes to require the FERC to approve and oversee a private self-regulatory organization that prescribes and enforces mandatory reliability standards.[52] In comparison, the NERC's Electric Reliability Panel, which was commissioned to study reliability issues, recommended that a reorganized NERC—called the North American Electric Reliability Organization (NAERO)—should have sufficient authority to enforce compliance with reliability standards. NAERO would be recognized by government bodies as a self-regulating organization.

As it stands now, it is not clear who will enforce reliability and under what authority. Solutions to the enforcement issues and a myriad of other complicated reliability issues will likely affect in undetermined ways the ISOs now operating and those that are now being formed. For example, the ISO's role for maintaining reliability under a voluntary compliance program might expand to include enforcement if a mandatory compliance program is established.

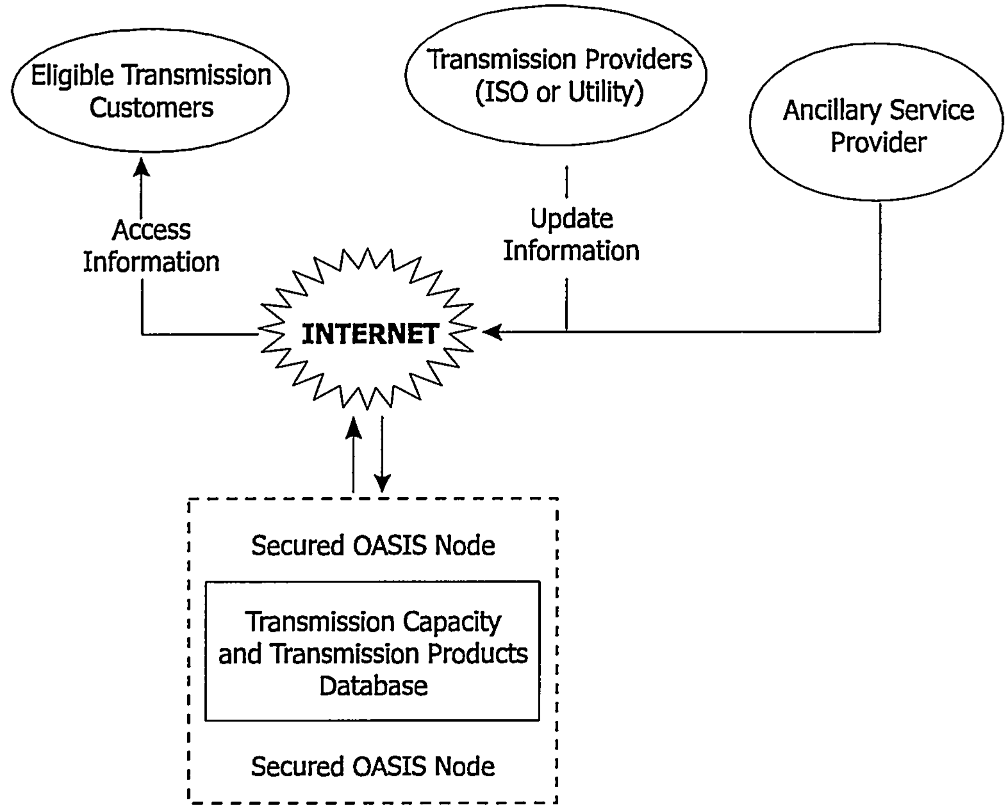
ISOs and the Open Access Same-Time Information System

The Open Access Same-Time Information System (OASIS) is an interactive Internet-based database developed by the electric power industry (Figure 20). The database, which will be used by transmission providers and transmission customers, contains information on transmission capacity reservations, ancillary services, and transmission prices (Table 16). The underlying idea of the OASIS is to create an interactive computerized market for transmission reservations, along with other transmission-related products and services. In that role, the OASIS facilitates equal and comparable access to the transmission grid, and it supports a competitive wholesale electricity market.

OASIS will be developed in two phases. Phase I was completed in January 1997, when the system became operational. Based on a few months of experience, Phase I-A was started to implement short-term improvements in OASIS requested by FERC and by the industry. Phase I-A is ongoing. Phase II is intended to expand the system's functionality by adding capability to process

[51] *Ibid.*, p. 18.
[52] U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 25, 1998), p. 6-7.

Figure 20. Overview Concept of an OASIS Node



Note: As of January 1998, 174 transmission providers maintain 27 OASIS nodes.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

energy transactions, to manage transmission constraints, and to place next-hour reservations and schedules.

The FERC required development of the OASIS, with mandatory participation for those utilities under FERC's jurisdiction.[53] FERC's jurisdiction covers utilities owning about 70 percent of the Nation's transmission grid. A significant number of nonjurisdictional transmission providers also participate in the OASIS, including several Canadian utilities. As of January 1998, 174 transmission providers share 27 nodes on the system. Three operational ISOs and three under development have OASIS nodes: ERCOT-Texas ISO, ISO-Nepool, PJM-ISO, New York ISO, MAPP, and SPP.[54] For its electronic information exchange needs, California ISO built the Western Energy Network (Wenet), a system that is separate from the OASIS. Wenet does not satisfy OASIS requirements, and the FERC granted the California ISO an interim waiver with instructions that it must comply with Phase II.

The OASIS concept is an innovative tool developed by the industry to manage and disseminate information that will make the industry more competitive; however, OASIS has an uncertain future. Although OASIS has had some successes, it also has had serious development and operating problems, and at present it is not an entirely useful or effective tool for supporting a competitive wholesale market.[55] Some of the problems are that the system is hard to use, the nodes lack standardization of terms and graphics, and definitions and business practices are inconsistent across nodes. Many of these problems should be solved during Phase I-A.

[53] Federal Energy Regulatory Administration, *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, 18 CFR Part 37 (April 24, 1996).

[54] A complete list of transmission providers and OASIS nodes can be obtained from web site www.tsin.com.

[55] Federal Energy Regulatory Commission, *Industry Report to the Federal Energy Regulatory Commission on the Future of OASIS* (October 31, 1997).

Table 16. Major Categories of Information on the Open Access Same-Time Information System (OASIS)

Information Category	Comments
Total and Available Transmission Line Capacity	The Transmission Provider (TP) will post firm and non-firm service for unconstrained capacity and constrained capacity on transmission paths over which power flows.
Transmission Service Products and Prices	The TP will post prices and a summary of the terms and conditions of transmission products, and a downloadable file of its tariffs will be available.
Ancillary Service Offerings and Prices	The TP will post the ancillary services it is required by the open access rule to provide. Third-party services can also be posted.
Transmission Service Requests and Responses	All requests by customers for transmission service must be posted.
Facility Status Information	Information for this category is under development. In Phase II of OASIS, information on the run status of generation and transmission may be posted.
Transmission Service Schedules	Downloadable files of scheduled transmission service will be available.
Transmission-Related Communications	The TP will post such items as transmission-related messages and want ads, and provide for using the OASIS as a transmission-related conference space.

Source: Federal Energy Regulatory Administration, *Open Access Same-Time Information Systems and Standards of Conduct*, Order No. 889, 18 CFR Part 37 (Washington, DC, April 24, 1996).

A broader issue concerns regional tariffs and their effect on OASIS. OASIS was conceived as a nationwide system serving all transmission customers with standardized procedures and protocols. Regional transmission tariffs have been approved, however, with nonstandardized procedures and protocols that are not compatible with the OASIS design. For example, New York ISO, ISO-New England, and PJM-ISO have regional tariffs that either do not use transmission reservations as defined in OASIS, or use a different process for transmission reservations. The California ISO and PX are adopting a system in which transmission reservations are irrelevant, because all schedules for transmission service are accepted, although they may be adjusted. More regional tariffs are likely as the ISO movement continues. It is safe to conclude that regional differences will increase the complexity and costs of the OASIS.

Summary and Conclusion

Eleven ISOs are currently being formed in the United States. California ISO, ISO-New England, and PJM-ISO have received conditional approval from the FERC, and the ERCOT-Texas ISO, which did not require FERC's approval, is in operation. The other seven ISO proposals are either under review or in different planning stages.

The ISO is a relatively new concept in the electric power industry, brought on primarily by the need to ensure nondiscriminatory access to the transmission system. With more experience, the role and importance of the ISO in the industry will likely expand. Most of the ISOs now being formed will be responsible for control and reliability of the transmission system, ensuring open access, administering a regional transmission tariff, transmission system planning, and, in some instances, facilitating regional wholesale power markets.

Competition and the increasing number of transactions and players in the wholesale energy market will make the ISO's responsibility for system reliability more difficult to carry out. ISOs are experimenting with new approaches to transmission pricing which, if successful, should make the overall industry more efficient.

4. Ratesetting and Consumer Choice Issues in Electricity Restructuring

Background

Currently, major electric utilities in the United States are vertically integrated, owning generation, transmission, and distribution facilities. These utilities operate as natural monopolies in exclusive franchised areas (awarded by the States) in return for the universal obligation to serve. The bundled rates they charge are determined by the cost-based service provided.[56]

The evolution of the current industry organization and structure results from the legal and regulatory system under which the industry has operated in the past. Since utilities are considered to be natural monopolies, regulation is expected to be a surrogate for a competitive environment with respect to the prices a monopoly could otherwise charge. This conceptual underpinning explains the extensive and comprehensive nature of the regulatory regimes under which the electric utilities have operated since the turn of the century.

Directives contained in FERC Orders 888 and 889 are designed to create an environment conducive to competition in wholesale electricity trade (see boxes on pages 52-55). However, the contemplated industry transformation from a regulated monopoly with cost-of-service pricing and an obligation to serve to a fully competitive generation market poses a host of complex and controversial issues.[57] Stakeholders' views expressed in the workshops organized by the U.S. Senate Committee on Energy and Natural Resources and the House Subcommittee on Energy and Power in 1997 exemplify the range of complexities inherent in the industry transformation process.[58]

Sharp differences in the perspectives and priorities of various stakeholders on significant issues contribute to the prevailing uncertainty as regulatory authorities and legislators grapple with issues that need to be resolved. Critics contend that the painless moiety—competition and customer choice—is granted by the Federal Government, but difficult matters have been left to the States to resolve.[59] It is not surprising that most State regulatory authorities eager to define a framework to promote competition at the retail level find the path they should adopt to be uncharted.[60] For this reason, most States are in varying stages of information gathering and/or consensus building and view with disfavor any Federal attempt to stipulate a designated date for the commencement of competition at the retail level.[61]

[56] For an overview of the electric power industry in the United States, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 3-28.

[57] Statement by James Hoecker, FERC Chairman, at the National Association of Regulatory Commissioners Summer Meetings in San Francisco, CA (July 1997), reported in *Electric Utility Week* (July 28, 1997), p. 1.

[58] The U.S. Senate Committee on Natural Resources organized four workshops in early 1997 to gather information about stakeholders' views on issues dealing with "competitive change in the electric power industry." The Committee's main objective in arranging these workshops was to define a fair pathway (with supporting Federal legislation where deemed necessary) in implementing competition so that its benefits accrue to all customers. The House Subcommittee on Energy and Power undertook a similar effort by holding a series of field hearings on the subject of "electric power to choose" during the same time period. Additional details regarding these workshops and field-hearings can be found on the respective home pages of the Committees. See web sites www.senate.gov/~energy/competit.htm and www.house.gov/commerce/releases/electric/handbook.htm.

[59] Rep. Clifford Sterns, "Haste Can Lay Waste to Industry," *Roll Call* (February 24, 1997). The "painless moiety" (i.e., the relatively straightforward part of the restructuring process) refers to the actions initiated by the FERC, leaving a host of other controversial issues to be sorted out by the States.

[60] Note that only a small number of States (California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia) have enacted legislation to promote competition at the retail level.

[61] According to a press release dated July 9, 1997, from the House Commerce Committee, the Pennsylvania Congressional delegation sent a letter requesting a Federal date for the State implementation of competition in the electricity markets. Other States that have already implemented legislation may or may not be in a position to support this request. Other States (like Florida and Georgia) have urged Congress not to adopt legislation that mandates retail access.

Major Provisions of FERC Order 888 on Stranded Costs

Stranded Cost Requirement

The recovery of legitimate and verifiable stranded costs shall be allowed. Direct assignment of stranded costs computed on a revenues lost basis is the appropriate method for recovery.

Wholesale Stranded Cost Definition

Any legitimate, prudent, and verifiable cost incurred by a utility to provide service to a wholesale requirements customer, a retail customer, or a newly created wholesale power sales customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such utility.

Contract Definitions

A new contract is one executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994.

An existing contract is one executed on or before July 11, 1994.

Stranded Cost Recovery Under New Contracts

A public utility may not seek recovery of stranded costs under new contracts except in accordance with an exit fee or other explicit provision contained in the contract. Prior notice to FERC of termination of new power sales contracts is no longer required.

Stranded Cost Recovery Under Existing Contracts

A public utility may seek recovery of stranded costs under existing contracts that do not contain exit fees or other explicit stranded cost provisions as follows:

- The parties may negotiate a stranded cost amendment and file it with FERC.
- Either party may seek FERC approval of a stranded cost amendment under Section 205 or 206 any time prior to the expiration of the contract.
- The public utility or transmitting utility may file a proposal to recover stranded costs through Section 205 or Section 211-212 rates for wholesale transmission services to the customer.

FERC will reject stranded cost amendments to existing contracts that include explicit provisions for payment of stranded costs or exit fees.

Stranded Cost Recovery for Retail-Turned-Wholesale Customers

FERC shall be the primary forum for addressing recovery of stranded costs caused by retail-turned-wholesale customers. A utility may seek recovery of stranded costs associated with a retail customer who becomes a legitimate wholesale transmission customer as a result of access to wholesale transmission through rates for wholesale transmission services to that customer. An evidentiary demonstration must be made. Any recovery permitted by a State will be deducted from the FERC-determined stranded cost recovery.

Recovery of Retail Stranded Costs

Although both FERC and States have the legal authority to address retail stranded costs, FERC determined that States should have primary jurisdiction over the recovery of stranded costs arising from retail wheeling. A utility may seek recovery of stranded costs through transmission rates from customers who obtain retail wheeling only if the State regulator has no authority under State law to address stranded costs at the time retail wheeling is required. A similar evidentiary demonstration must be made.

(continued on page 53)

Major Provisions of FERC Order 888 on Stranded Costs (Continued)

Evidentiary Demonstration

A utility seeking recovery of stranded costs must demonstrate that it incurred the costs on behalf of the wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer.

If the existing contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

Whether State law awards exclusive service territories and imposes a mandatory obligation to serve would be among the factors to be considered in determining whether the reasonable expectation test is met in a particular case involving either a retail or retail-turned-wholesale customer.

Determination of Recoverable Wholesale Stranded Costs

Determination of recoverable stranded costs shall be based on a "revenues lost" approach. The utility shall calculate a customer's stranded cost liability using the following formula:

SCO = (RSE - CMVE) x L where

SCO = Stranded cost obligation

RSE = Average annual revenues from the departing generation customer over the 3 years prior to the customer's departure (with the variable cost component of revenues clearly identified), less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same 3 years under its new wholesale transmission tariff

CMVE = Competitive market value estimate either from sale of released capacity or the average annual cost to the customer of replacement capacity and associated energy

L = Length of obligation (reasonable expectation period).

(RSE – CMVE) can be no greater than the customer's average annual contribution to fixed power supply costs if it had remained a customer. Payment method and terms should be negotiated but is ultimately at the option of the customer. The customer, at its sole discretion, can choose to market or broker the released capacity and associated energy.

Advanced Notice of Stranded Cost Calculation

Prior to the termination date of an existing contract, a customer may request the utility to calculate the customer's stranded costs exposure using the prescribed formula. The utility would have 30 days or a mutually agreed upon period to respond. If the customer believes that the utility has failed to establish reasonable expectation, the customer has 30 days to respond so to the utility. If the parties cannot reach a mutually agreeable charge within a reasonable time period, the customer can file a complaint with FERC or contest the charge when the utility files it.

Source: Adapted from "FERC Finalizes Electric Industry Restructuring Rule," *Public Utility Topics*, No. 96-2 (Philadelphia, PA: Coopers & Lybrand, L.L.P., June/July 1996), pp. 4-8.

Even in areas where the FERC and the States have provided specific guidelines, conceptual and procedural differences remain. As an example, recovery of stranded costs is critical for investor-owned utilities, but estimating utility-specific stranded costs at a given point in time is difficult.[62] In addition, low-cost power

[62] FERC defines wholesale stranded costs "as any legitimate, prudent and verifiable costs incurred by a public utility or a transmitting utility to provide a service to a wholesale requirement customer that subsequently becomes, whole or in part, an unbundled transmission services customer of that public utility or transmitting utility." Refer to Federal Energy Regulatory Commission, Notice of Proposed Rulemaking (NOPR) and Supplemental Notice of Proposed Rulemaking March 29, 1995). The NOPR is made up of two dockets: (i) *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Docket No. RM95-8-000, and (ii) *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Docket No. RM94-7-001. An unbundled transmission services customer, as defined in the NOPR, is one who purchases transmission as a product that is separate from the purchase of generation. According to FERC, the onus of identifying recoverable wholesale costs rests on utilities. Treatment of stranded costs by States is discussed on pages 59-69 and in Appendix E, pages 145-166.

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.

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 systemwide *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.

Customer Eligibility

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

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.

(continued on page 55)

producers consider this requirement to be an artificially contrived obstacle to delay the benefits of competition.[63] Environmental proponents are less concerned with stranded cost issues and more concerned about the pollutants that could be produced by increased generation from low-cost, coal-burning power plants in the Midwest. These opposing viewpoints need to be reconciled so that the transition can proceed smoothly without impairing the reliability, security, and stability of the existing power system.

[63] Organizations like the Electricity Consumers Resource Council (ELCON) have opposed stranded cost recovery since the very beginning. A newly formed coalition named "Stop the Bailout" is actively opposed to the recovery of stranded costs. Its members include the Heritage Foundation, the Competitive Enterprise Institute, Citizens for a Sound Economy, Friends of the Earth, Public Citizen, the Safe Energy Communication Council, and the U.S. Public Interest Research Group. See *Electricity Week* (August 11, 1997).

Major Provisions of FERC Order 888 on Open Access (Continued)

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.

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.

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*, No. 96-2 (Philadelphia, PA: Coopers & Lybrand, L.L.P., June/July 1996), pp. 4-8.

In the circumstances described, the search for a solution tends to be time-consuming. It also fails to fully satisfy the demands of contending stakeholders. In introducing competition in electricity, "as in so many endeavors, the devil will be in the details."[64]

Stakeholders involved in the transition include utilities, State and Federal governments, legislative interests, traders and investors, environmentalists, public policy program advocates, multiple special interest groups, and various customer class groups (Figure 21). In addition, coalitions (new and old) that either lend or deny support to exclusively defined objectives or special interests play a significant role. The participation of such a large group on any issue complicates the search for quick solutions.

[64] C.B. Curtis, "The Devil is in the Details of Electricity Deregulation," *Roll Call* (February 24, 1997). Also, E. Hirst and B. Kirby, "Restructuring—The Devil *Is* in the Details," *Electricity Journal* (December 1995), pp. 12-18.

Figure 21. Groups with an Interest in Electric Industry Restructuring

Electricity Industry Restructuring Interests

Customers

- ✔ Residential
- ✔ Commercial
- ✔ Industrial
- ✔ Other

Special Interest Groups

- ✔ Low-Income Advocates
- ✔ Ratepayer Advocates
- ✔ Residential/Rural Interest Groups
- ✔ Trade Organizations
- ✔ Environmental Groups
- ✔ Sustainable Energy Advocates

State and Federal Government Agencies[1]

- ✔ U.S. Department of Energy
- ✔ Federal Energy Regulatory Commission
- ✔ Nuclear Regulatory Commission
- ✔ Environmental Protection Agency
- ✔ Securities and Exchange Commission
- ✔ Internal Revenue Service
- ✔ Department of Justice
- ✔ State and Local Government Agencies
- ✔ Public Utility Commissions

Utilities

- ✔ Investor-Owned Utilities
- ✔ Federally Owned Utilities
- ✔ Other Publicly Owned Utilities
- ✔ Cooperatively Owned Utilities
- ✔ Nonutility Generators

Financial Stakeholders

- ✔ Financial Institutions/Rating Agencies
- ✔ Shareholders and Investors
- ✔ Equity and Bondholders
- ✔ Research & Development Companies
- ✔ Equipment Manufacturers and Fuel Suppliers
- ✔ Power Marketers, Traders, and Brokers

[1]This is a partial list of State and Federal agencies with interests in the electricity industry.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Restructuring Choice Issues

As the wholesale markets open and the requisite institutional infrastructures like independent system operators (ISOs) and the Open Access Same-Time Information System (OASIS) evolve and become operational, the electric utilities will be under considerable pressure to reorganize and restructure. Besides initiating efficiency improvements and securing productivity gains, utilities may also attempt to position themselves strategically to meet competitive challenges. Introduction of retail competition in the States will tend to accelerate industry restructuring as utilities consolidate and expand existing boundaries of business (excluding power generation).[65] There may also be a trend leading to a convergence between electricity and natural gas companies.

In this environment of industry changes, the range of consumer choices will be determined by basic decisions at the State level.[66] Of the many variables likely to affect the decisionmaking process, perhaps the most critical (and contentious) issue may be the manner in which the States authorize the recovery of costs likely to be stranded.[67] The FERC supported full recovery of stranded costs resulting from its promotion of wholesale trade in electricity. Based on the concept of regulatory compact, utilities expect supportive treatment from State regulatory authorities in promoting electricity

[65] "The obligation to serve will convert to an obligation to connect. Utilities will simply energize the wires." Statement attributed to Scott Neitzel, Member, Wisconsin Public Service Commission, in an article "Network Trouble" in *Public Utility Fortnightly* (March 15, 1996).

[66] The possibility that some States may decide to defer or even reject competition in retail trade in electricity should not be overlooked.

[67] The emerging competitive market for electricity envisions that the existing utility customers will be able to secure power from alternative, lower-priced suppliers. When this occurs, the utility that originally supplied power to a departing customer may not be in a position to market the power to an alternative customer. The utility thus suffers a financial loss due to structural changes in the industry, leading to the creation of stranded costs. Note, however, that explaining the emergence of stranded costs in this manner masks complexities inherent in defining the term.

competition at the retail level.[68] Where this support is not fully forthcoming, delay in introducing competition becomes a distinct possibility.[69]

This chapter addresses two ratesetting issues: (1) approaches adopted by State regulatory authorities in their treatment of stranded costs and (2) performance-based rates. Other consumer choice issues are highlighted in a discussion of experiments with pilot programs.

Stranded Cost Developments in the Post-888 Era

During the transition to a competitive environment, the FERC noted that some utilities may incur stranded costs as wholesale customers leave to purchase power from alternative sources. Accordingly, Order 888 provided a mechanism for recovery of stranded costs with a view to ensuring an orderly and structured transition to a wholesale market that would increasingly rely on market-based generation rates in the future.

A number of stakeholders—137 in all—filed requests for rehearing and/or clarification of FERC Order 888. Although the Commission's basic tenet, the need to harness the benefits of competitive market forces in electricity pricing, received general acceptance, stakeholders nevertheless raised many issues concerning the legal, technical, and policy implications of Order 888.

The stakeholders' disagreements, for the most part, focused on the mechanics of promoting competition: who should pay the costs of transition and how long should the transition take?[70] However, the most contentious arguments during the rehearing involved how the FERC should deal with the transition costs associated with moving to competition.[71]

Most utilities wanted a guarantee with respect to the full recovery of stranded costs whether caused by loss of wholesale or retail customers. Many customers, however, sought the ability to abrogate existing wholesale contracts without any payment for stranded costs.[72] The Commission's Order on Rehearing (Order No. 888-A) issued in early 1997 reflects a reconciliation of two contrasting views on the recovery of stranded costs.[73]

In its Order 888-A, the FERC (while reaffirming its stranded cost recovery mechanism stated in Order 888) aims to balance a number of critical interests to achieve a fair and orderly transition to competition. These include sustaining the financial stability of the industry, upholding the regulatory bargain under which large investments were made by the industry in the past, and not shifting costs to customers that had no responsibility in causing stranded costs to emerge. The Commission acknowledged that stranded cost recovery may delay some of the benefits of competition but concluded that customers will benefit in the long run from a fair and orderly transition.

The Commission's reaffirmation (in Order 888-A) includes the following key components:

- Utilities will be allowed the opportunity to recover legitimate, prudent, and verifiable wholesale

[68] The term "regulatory compact" should not be construed to be an agreed-upon contractual relationship between the utilities and their regulators. Rather, the regulatory compact is an evolutionary relationship involving a judicious balancing of utilities' rights and responsibilities. In return for the exclusive franchise (implying protection from competition), the utilities have an obligation to serve, to provide safe and reliable service, and to charge prices that are *just and reasonable* (determined by regulation) but not discriminatory. For additional information, refer to the National Regulatory Research Institute, *An Economic and Legal Perspective on Electric Utility Transition Costs* (Ohio, July 1996), pp. 39-72. Also, California Public Utilities Commission, *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future* (California, February 1993), pp. 7-15.

[69] The New Hampshire Pubic Utilities Commission (NHPUC), for example, limited recovery of stranded costs where the responsibility for resource decisions and the associated asset acquisitions could be attributed primarily to utility management. In all other cases, where State utilities' decisions were not compromised by the New Hampshire legislators or the regulators, the utilities were to be allowed an appropriate opportunity for full recovery. This decision (as well as the methodology used in computing stranded costs) led the Public Service Company of New Hampshire (PSNH) to secure a restraining order preventing the NHPUC from moving forward with any part of its restructuring plans.

[70] Order 888-A, p. 6.

[71] *Ibid.*, p. 6.

[72] The National Association of Utility Consumer Advocates (NASUCA), American Public Power Association (APPA), and Electricity Consumers Resource Council (ELCON) are among some of the organizations that opposed recovery of stranded costs. Low-cost utilities and industrial units (that use electricity intensively) also provide support for this position. The Edison Electric Institute (EEI) and organizations linked with independent power producers demand recovery of stranded costs that include additional items besides uneconomic generating assets.

[73] Federal Energy Regulatory Commission, Docket Nos. RM95-8-001 and RM94-7-002; Order No. 888-A (Order on Rehearing) *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* (March 4, 1997), p. 490.

stranded costs associated with (i) wholesale requirements contracts (executed on or before July 11, 1994) that do not contain explicit stranded cost recovery provisions and (ii) costs associated with serving retail-turned-wholesale customers.[74] This opportunity will be available regardless of whether the customer or the new supplier requests and contracts for transmission service. To accommodate the concept, the definition of "wholesale stranded costs" was revised.[75]

- The opportunity to recover stranded costs, in each case, is limited to situations where there is a *direct nexus* between the availability and use of FERC-required transmission tariffs and the stranding of costs. Other cost recovery issues are thus excluded from consideration.

- The Commission stated that (under certain conditions) it would be in the public interest to permit amendments to wholesale requirements contracts to include stranded cost provisions.

- The Commission pointed out that provisions of Order 888 provide an *opportunity* to the utilities to recover stranded costs without offering a *guarantee* that recovery will be allowed.[76] To be eligible for recovery of stranded costs, a utility must demonstrate that costs incurred in providing services to a customer were based on a reasonable expectation of continuing services beyond the contract date.

- The Commission reaffirmed the direct assignment of stranded costs to the departing customer as the appropriate recovery method. Adoption of this cost causation approach eliminates the need to defray stranded costs to all transmission users of a utility.

- Instances where retail customers convert to wholesale customers (through municipalization) involve new and complex jurisdictional issues. The Commission will be the forum only in those limited cases where there is a *direct nexus* between the availability and use of FERC-required transmission access and the stranding of costs.

- The Commission reaffirmed its conclusion that both it and the States have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in interstate commerce to reach a different supplier. The only circumstance in which the Commission will entertain requests (to recover stranded costs caused by retail wheeling) is when the State regulatory authority does not have the authority under State law to address stranded costs when retail wheeling is required. The Commission thus steps in to fill a regulatory "gap" (without any intent to preempt the exercise of any State authority). If a State regulatory authority addresses such costs, the utility(ies) may not then apply to the Commission regardless of whether full or partial or no recovery was allowed.

[74] In terms of the provisions of Order 888, the Commission was to be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. This decision was based on a clear nexus between the FERC-jurisdictional transmission access requirement and the exposure to nonrecovery of prudently incurred costs. However, FERC had also stated that it would *not* be the primary forum in instances where an existing municipal utility annexes territory served by another utility or expands its territory. On rehearing, the Commission reserved the right to address such situations on a case-by-case basis. Commissioner Massey dissented with this decision by the Commission just as he had dissented with the notion of FERC being the primary forum for recovery of stranded costs in case of municipalization.

[75] Wholesale stranded cost, as defined in Order 888, means any legitimate, prudent, and verifiable cost incurred by a public utility or a transmitting utility to:

(i) a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

Order 888-A modifies (ii) to read as follows:

(ii) a retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

[76] On this issue, the Commission stated that "allowing full recovery of stranded costs under Order 888 is not equivalent to allowing 100 percent recovery of the costs of all uneconomic assets," Order 888-A, p. 578.

- The "revenues lost approach" methodology was reaffirmed to be the fairest and most efficient way for calculating stranded costs to be assigned to a departing customer.[77] The Commission rejected the asset-by-asset valuation approach as being overly complicated and costly.[78]

In reaffirming its stand on various issues pertaining to the recovery of stranded costs, the Commission "struck a reasonable balance that, for certain defined circumstances, permits utilities the opportunity to seek extra-contractual recovery of stranded costs from their departing customers and permits customers the opportunity to make a showing that their contracts should be shortened or terminated."[79]

Treatment of Stranded Costs by States

Electricity is expected to become available at prices below those currently prevailing as a competitive market for electricity develops at the retail level in States.[80] Evidence of this shift may be more visible in States where average electricity prices are well above the national average than in those where prices are well below the national average.[81] During the transition period prices are to be determined by market forces, and high-cost utilities may be unable to fully recoup the embedded costs of their investments. The amount by which the embedded cost of a utility exceeds the market value of an asset is generally referred to as stranded cost.[82]

A recent Edison Electric Institute (EEI) report noted that the quickest and most pragmatic way to get competitive power is to offer the incumbent utilities the tools and flexibility to collect their "stranded" or transition costs.[83] The EEI maintains that a significant portion of the stranded costs (such as nuclear investments and independent power contracts) is attributable to public policies of the past.[84] Recovery of stranded costs is thus based on equity and fairness arguments.

Investor-owned utilities hold similar views and claim that they should be entitled to a full and timely recovery of stranded costs. Their arguments rest on the familiar notion that a regulatory compact entitles them to recoup reasonably adequate returns on invested capital.[85] As this option may no longer be feasible (at least for high-cost utilities) under competition, recovery of stranded

[77] FERC's determination of recoverable wholesale stranded costs takes the following form:

SCO	=	(RSE-CMVE)xL where
SCO	=	Present value of stranded cost obligation
RSE	=	Revenue stream attributable to the departing customer based on the average of three prior year's revenues
CMVE	=	Competitive market value (of power) estimate either from the sale of released capacity on an average annual basis or the average annual cost to the customer of replacement capacity and associated energy
L	=	Length of obligation (reasonable expectation period).

[78] Order 888-A, pp. 711-762.

[79] Federal Energy Regulatory Commission, Docket Nos. RM95-8-001 and RM94-7-002; Order No. 888-A (Order on Rehearing), *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* (March 4, 1997), p. 6.

[80] Note that generation and distribution prices will be unbundled from the total electricity price, and the ratesetting methodology may vary between the two prices. In the short run, generation, transmission, and distribution may continue to be cost-of-service-based rates. In the long run, however, generation prices will begin to approximate their long-run marginal costs.

[81] Average electricity prices in July 1997 ranged from a low of 3.8 cents per kilowatthour in Idaho to 11.9 cents per kilowatthour in New Hampshire (with the national average being 7.28 cents per kilowatthour). Energy Information Administration, *Electric Power Monthly,* DOE/EIA-0226(97/10) (Washington, DC, October 1997), Table 53, p. 60.

[82] Most States define stranded costs using this basic concept with some minor changes. As an example, the Public Utilities Commission of Texas defines stranded investment as the "historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market." Note, however, that the term "stranded cost" is difficult to define.

[83] Note that stranded costs are also known as stranded investments, stranded commitments, transition costs, excess costs over market, embedded costs exceeding market prices, uneconomic sunk costs, or costs without a customer.

[84] Edison Electric Institute, *The Path of Least Resistance: Accelerating the Movement to Electric Industry Competition through Transition Cost Competition* (Washington, DC, November 1997).

[85] The term regulatory compact is used to describe an implicit relationship existing between the utilities and the regulators. In return for grant of franchises, utilities maintain that they accepted an obligation to serve, develop, and maintain the requisite electricity infrastructure in exchange for an opportunity to recover the reasonable costs of financial commitments incurred to meet public service obligations. This viewpoint is, however, challenged by some stakeholders. R. S. Hartmen and R. D. Tabors, *The Regulatory Contract and Its Relevance to Stranded Assets Under Restructuring : A Modest Proposal* (Cambridge, MA: Cambridge Economics Inc., October 1996).

costs is deemed necessary to maintain the financial viability and operational reliability of this critically important infrastructure. A subset of the regulatory compact argument also raises issues associated with usurpation of property, which is precluded by law, in the event that stranded cost recovery is denied.[86]

Industrial users are particularly interested in securing lower electricity rates, and they view *full* stranded cost recovery as an impediment delaying the benefits of competition.[87] Discussing this subject in the early stages of the restructuring debate, the Electricity Consumers Resource Council (ELCON) outlined a five-step process for the recovery of net stranded costs associated with nonmitigable uneconomic assets resulting from transition to competition at the retail and wholesale levels.[88] The Electricity Customer Choice Group (ECCG) has recently supported a similar position with respect to the recovery of stranded costs.[89]

Some commercial and residential customers do not support full stranded cost recovery for similar reasons. The National Association of State Utility Consumer Advocates (NASUCA) rejects utilities' claims for full recovery of stranded costs and would prefer that States and State public utility commissions "determine the appropriate recovery by utilities of uneconomic costs that are stranded as a result of retail access."[90]

Independent power producers (IPPs) are in a unique predicament in this debate as existing suppliers to the utilities and also as potential contenders in the emerging competitive market for electricity. IPPs that currently supply power to the utilities at wholesale (in terms of contracts negotiated under the aegis of PURPA regulations) favor stranded cost recovery.[91] These IPPs rely on the sanctity of contractual relationships and are aware that a number of their contracts saddle the utilities with stranded cost liabilities.[92] However, IPPs planning to compete in the market may not support stranded cost recovery with equal enthusiasm.

Arguments supporting recovery of stranded costs in the States are familiar. The financial stakes are large. Estimates of nationwide stranded costs (in the median range) fall between $100 and $200 billion.[93] The $200 billion estimate of stranded asset valuations is comparable with the aggregate equity of the industry.[94]

States contemplating transition to competition generally start with investigations that involve a wide spectrum of stakeholders to develop a framework incorporating principles, goals, and objectives that need to be sustained as the electric industry transitions to a competitive mode.[95] In nearly every State where investigations have been completed, perhaps the most critical and contentious issue is the proposed treatment of stranded costs.

[86] W. J. Baumol and J.G. Sidak, *Transmission Pricing and Stranded Costs in the Electric Power Industry* (Washington, DC: The AEI Press, 1995), pp. 98-114.

[87] Testimony of Pete Mehra at the Senate Energy and Natural Resources Committee Workshop (March 6, 1997) on "Competitive Change in the Electric Power Industry—What Are the Issues Involved in Competition?" Mr. Mehra testified on behalf of Ford Motors, the Electricity Consumers Resource Council (ELCON), and the Electricity Customer Choice Group (ECCG). Both ELCON and ECCG represent large industrial users of electricity.

[88] The five steps suggested by ELCON include: determination of extent of uneconomic assets, determination of sharing mechanism between shareholders and customers, negotiation of recovery mechanisms, setting recovery period, and a truing-up of recoverable costs. Refer to Electricity Consumers Resource Council, *Blueprint for Customer Choice–Road Map for the Transition* (Washington, DC, December 1995).

[89] In its *Policy Statements*, the ECCG states that retail transition costs should be determined by the States within Federal guidelines. The recently formed organization represents a broad range of manufacturing interests across the United States. Extracted from the ECCG web site at www.eccg.org on January 5, 1998.

[90] Testimony of Irwin A. Popowsky, Consumer Advocate of Pennsylvania, on October 22, 1997, before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power, Hearings on H.R. 655, *Electric Consumers' Power to Choose Act*, on behalf of NASUCA.

[91] According to recent estimates provided by Resources Data International, stranded costs attributable to power purchase contracts account for about $54 billion out of a total of $202 billion. "Shorts and Transients," *The Electricity Journal* (April 1997).

[92] In 1996, nonutility generators owned 73.2 gigawatts of capacity and generated 382.5 million kilowatthours of electricity. Deliveries to the utilities totaled 224.7 million kilowatthours. Energy Information Administration, *Electric Power Annual 1996, Volume II*, , DOE/EIA-0348(96/2) (Washington, DC, December 1997), Table 53, p. 93.

[93] Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 78-82. More recent estimates from Data Resources Inc. project the net value of the stranded assets to be $203.8 billion. Refer also to DRI/McGraw Hill, *World Energy Service: U.S. Outlook* (Spring 1997), pp. 119-121.

[94] Aggregate equity investments of investor-owned electric utilities, as of December 31, 1996, were $193.2 billion. Energy Information Administration, *Financial Statistics of Investor-Owned Electric Utilities*, DOE/EIA-0437(96/1) (Washington, DC, December 1997).

[95] The initial investigation may be undertaken at the request of the State regulatory authorities or of the State legislature. In some cases, the process may be initiated at the request of utilities.

Initial estimation attempts at the State level start with defining stranded costs, together with a discussion and identification of contributory factors that lead to the emergence of stranded costs in their jurisdictions. At the same time, States invariably undertake to provide the utilities with a fair or a reasonable opportunity (comparable to that under the existing regulation) for recovery of their stranded costs during a specified transition period prior to the beginning of full competition.[96]

Affirmation to accord the utilities an opportunity to recover stranded costs, as indicated above, is a difficult balancing act for the States. Allowing recovery would in some ways delay the expected electricity price reductions. Rejecting recovery could imperil the industry's financial viability, and could raise issues based on fairness, equity, and other legal considerations. Thus, the regulators require utilities to demonstrate that all practical steps to mitigate stranded costs have in fact been implemented before recovery of *just and reasonable* stranded costs is authorized.

Additional considerations, with a differing focus in each State, include the following:

- **Delineation of components making up stranded costs.** These usually include generation assets, purchased power agreements, fuel contracts, regulatory assets, employment transition costs, and environmental mandate costs.[97] Decommissioning obligations with respect to nuclear power plants and, in some cases, future operating or capital expenses are also included. Of these, only stranded costs relative to generating plants are backed by assets that can possibly be marketed. Thus, a significant portion of stranded costs may be represented by non-marketable assets, and their recovery may no longer be feasible in a competitive environment.

- **Estimation of potential stranded costs.** A utility can estimate potential stranded costs in one of two ways. It can compute the present value of its assets and compare the resulting valuation with its sunk or historical costs. Alternatively, it can compute the net present value of the aggregate revenue losses to be potentially sustained (for a given number of years) in the future as a function of projected electricity prices in the market. Estimations of stranded costs invariably net the negative value of above-market generating assets against the positive value of below-market costs.

These basic approaches can be varied, depending on when the estimates are made (i.e., before or after the commencement of competition at the wholesale and retail levels) and whether the estimates are made administratively or are determined by the market. These differing considerations enable categorization of available approaches.[98]

Regardless of the method adopted, State commissions invariably require utilities to submit estimates of stranded costs that they seek to recover. What follows next is a process similar to a rate case proceeding, in which various stakeholders and the regulators subject a utility's claim to scrutiny and objective assessment.

Based on recent decisions, a number of States have favored market solutions in preference to

[96] No State has yet accorded an absolute guarantee for recovery of stranded costs, even though assurances for full recovery are invariably included. The New Hampshire Public Utility Commission, which linked the recovery of stranded costs to regional price levels of electricity, is currently embroiled in a legal challenge filed by the Public Service Company of New Hampshire.

[97] Regulatory assets include deferred expenses (permissible under Financial Accounting Standard No. 71) that appear as assets on the balance sheet. Utilities have reasonable assurance to recover these assets in electric rates charged to customers in the future. This category could include any costs which could or would have been otherwise expensed under standard accounting conventions. Examples of its components include: regulatory tax assets recoverable through future rates, deferred finance charges, deferred environmental charges, unamortized property losses, unamortized demand-side management expenditures, certain post-retirement benefit costs, canceled plants for which unamortized costs have been allowed, and others.

[98] These categories generally are bottom-up versus top-down, *ex ante* versus *ex post*, and administrative versus market. For a summary of these approaches, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 143-145. For additional details, refer to Niagara Mohawk Power Corporation's filing with the New York Public Service Commission in Case Nos. 94-E-0098 and 94-E-0099, Phase II, *Multi Year Electric Rate, Restructuring and Retail Access Proposal* (Syracuse, NY, October 6, 1995). Also, refer to San Diego Gas and Electric Company, *Comments of San Diego Gas and Electric Company on Proposed Policy Governing Restructuring Electric Services Industry and Reforming Regulation*, submitted to the California Pubic Utility Commission, Docket No. R-94-04-031 (San Diego, CA, June 8, 1994). Additionally, refer to L. Baxter, E. Hirst, and S. Hadley, *Transition Cost Issues for a Restructuring Electricity Industry* (Oak Ridge, TN: Oak Ridge National Laboratory, March 1997), and W. Marcus and J. Hamrin, *A Guide to Stranded Cost and Valuation Methods* (San Francisco, CA: JBS Energy Inc., February 1997).

adoption of objective administrative determinations.[99] This explains why some State commissions have sought and secured divestiture of generation assets as a condition for permitting the utilities to recoup stranded costs. Announced divestiture plans by investor-owned utilities (in California, Illinois, Maine, Massachusetts, Montana, New Hampshire, New Jersey, New York, Oregon, Pennsylvania, and Rhode Island) indicate that more than 52 gigawatts of generating capacity was up for negotiated sales.[100] Where an agreement on sale price has been reached, incumbent utilities have sold their non-nuclear generating assets in excess of their book values (as in the case of New England Electric Systems, Boston Edison, and Southern California Edison). Whether divestiture enables a true valuation of generation assets is not, however, universally accepted.[101]

- **Adoption of strategies to mitigate stranded costs.**[102] Cost reduction (or cost containment) efforts and revenue enhancing strategies are the two common strategies. Other mitigation strategies may delay the onset of competition, alter depreciation options, reallocate costs, or restructure rates.[103]

  Not all State regulatory authorities agree with the above approach. The Indiana Utility Regulatory Commission (IURC), for example, contends that there is no sure method for estimating a "recovery number" in advance. Using an estimate of stranded costs as a basis to set up a recovery method, the IURC prefers that the estimates be revised to reflect the impact of any relevant market changes. As an alternative, the IURC supports making stranded cost recovery contingent upon a utility's divestiture of generation assets.[104]

- **Designation of recovery methods.** Several methods have been proposed by the States to recover stranded costs. Generally available options include: a nonbypassable variable charge based on kW/kWh usage; a fixed fee (including but not limited to an exit fee) independent of usage; and an access fee levied on suppliers. Each of these options has advantages and disadvantages associated with its implementation.

  Consider the nonbypassable wires charge. In its support it can be argued that the charge, which is based on demand and energy use, makes collection easy with the aid of existing metering devices. There is an element of transparency in its collection because of its clear link with the restructuring efforts and the associated stranded costs. Arguments against imposition of the wires charge dwell on its regressiveness and potential impacts on demand. In addition, the charge applies only to those who purchase competitive power and may or may not exclude new market entrants.

  Imposition of fixed fees creates a determinate liability, has no direct impacts on levels of consumption, and may minimize chances of an over or under recovery. However, it is unrelated to a customer's ability to pay and may be burdensome to low-end users. It also may distort usage levels.

  In choosing recovery mechanisms, State regulatory authorities tend to be guided by the impacts of such instruments. State regulatory authorities prefer that the recovery mechanisms be assessed for their impacts on rates.[105] The impacts should be fair, equitable, and nondiscriminatory. In addition, recovery mechanisms should promote economic

[99] Where administrative methods are used, stranded cost valuations hinge on the forecasting methodology adopted. In this process, the quality of data used and the assumptions with respect to a number of other variables become critically important. With a view to reduce forecast errors, true-up mechanisms enabling adjustments for over or under collections become necessary. Also, M.H. Rothkopf, "On Misusing Auctions to Value Stranded Assets," *Electricity Journal* (December 1997), pp. 10-17.

[100] *Electricity Journal*, April 1998, p. 6.

[101] It is not clear whether the purchase price of assets being divested reflects the true market value of the generating plants sold. Refer to the Virginia State Corporation Commission, *Draft Working Model for Restructuring the Electric Utility Industry in Virginia* (Richmond, VA, November 1997), Chapter 4.

[102] Note that a significant portion of stranded costs consists of embedded costs or obligations. These by definition cannot be mitigated. States, therefore, attempt to reallocate or offset them among stakeholders in a manner that reduces the potential loss to the equity holders.

[103] For a detailed discussion of mitigation strategies, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), Appendix E, pp. 143-157.

[104] Indiana Utility Regulatory Commission, *Energy Report: Public Policy Considerations*, submitted to the Regulatory Flexibility Committee of the Indiana General Assembly (November 1997).

[105] Recovery mechanisms that are integrated with performance-based ratemaking have also been advocated. Refer to K. Rose, *An Economic and Legal Perspective on Utility Transition Costs* (Columbus, OH: National Research Regulatory Institute, July 1996). Also, P. Joskow, "Does Stranded Cost Recovery Distort Competition," *The Electricity Journal* (April 1996).

efficiency (resulting in cost improvements) and provide utilities with a reasonable opportunity to recover their stranded costs.[106]

- **Securitization as an option for financing stranded costs.** Securitization is a technique permitting a utility to create intangible *transferable transition property rights* to be used as collateral for funding instruments issued pursuant to the enactment of enabling legislation by a State. In essence, the process allows the utilities to receive cash now in exchange for revenue streams from a nonbypassable transition charge (that the utility's customers will pay in the future based on their allowed stranded costs) earmarked exclusively for repaying the newly created funding instruments.

  Consider a simplified example. Assume that a utility with $10 billion in assets has $4 billion in strandable assets. Authorizing the utility to securitize its strandable assets implies a reduction in its assets (ratebase) and in its liabilities by $4 billion. This allows the utility to reduce its rates to the customers immediately. In view of this potential, securitization has a seductive appeal to some regulatory authorities even though customers continue to pay for liquidation of amounts securitized through separate charges.

  For securitization to become operational, utilities sell, assign, or transfer the statutorily created property rights to a financing vehicle. Securities can then be sold by a trust or any special-purpose vehicle set up for this purpose. Repayment of securities sold in this manner is supported by future revenue streams specifically designated by a levy on customers, usually known as the competition transition charge (CTC). Over time, the utility collects the CTC and uses the proceeds to liquidate the amount securitized. This process avoids the need for a guarantee by the State to liquidate the liability created, even though the process virtually ensures its eventual liquidation, because the CTC levy becomes irrevocable until the amount securitized is paid.[107]

  Some States (including California, Connecticut, Illinois, Montana, New Hampshire, Pennsylvania, and Rhode Island) have in fact adopted legislation designed to make this tool available to the utilities. In California, securitized bonds are called "rate reduction bonds," because the bonds are used to fund a 10-percent rate reduction in the State until the year 2002. Montana requires that savings resulting from securitization be applied to a rate freeze. Financial analysts anticipate that total stranded cost securitization may reach between $50 billion and $75 billion over the next 4 years.[108]

  Critics point out that the securitization strategy can be used in multiple situations and is not directly associated with electric industry restructuring. Perhaps the more serious criticism stems from the lack of specific directives regarding utilization of funds by the utilities.[109] Some competitors are apprehensive that the sudden inflow of funds may be used by the utilities to undertake anticompetitive measures rather than to lower asset-related liabilities. There is also the perception that securitization shelters the utilities from both regulation and competition in the future.[110] This criticism stems from the inability to revisit securitized costs and determine the appropriateness of future recovery.[111]

- **Stipulation of recovery period for stranded costs.** A short recovery period may lead to an earlier emergence of full-fledged retail competition than would be feasible under a long recovery period.[112] However, this option enhances the possibility for errors in recovery, because adjustments to estimates become difficult to implement. If the recovery period is long, adjustments to estimates become feasible even though competition may be

[106] Arizona Corporation Commission, *Stranded Cost Working Group Report to the Commission* (September 30, 1997).
[107] W.H. Hall II, "Securitization and Stranded Cost Recovery," *Energy Law Journal*, Vol. 18, No. 2 (1997), pp. 363-404.
[108] K.G. Baker and B.D. Fabrikant, *Stranded Utility Costs: Legislation Jolts the ABS Market* (Moody's Investor Service, February 28, 1997).
[109] D. Moody, "IOU Tricks for Securing Their Futures," *Public Power* (September/October 1997), pp. 37-38. Also, J.R. Hodowal, "The Securitization Swindle: Bailout for the Utilities, Bad Deal for Consumers," *Electricity Journal* (October 1997), pp. 44-53.
[110] New York State Assembly, *Shedding Light on Securitization: A Briefing Paper on Moving to Competition in the Electric Industry* (January 1997).
[111] Dr. Kenneth Rose, National Regulatory Research Institute, points out that utilities may use the cash to buy back stock or retire debt for investment in foreign countries, or "to buy land in Freedonia." Presentation at the National Association of Regulatory Utility Commissioners (July 1997).
[112] California, for example, has a 4-year period for recovery of stranded costs with respect to utility-owned generation assets.

somewhat delayed.[113] There is, however, no consensus on this issue.

As States continue to negotiate workable arrangements with stakeholders for a transition to competition, securing a collaborative agreement with respect to stranded cost issues (with jurisdictional utilities) constitutes a critical step toward success. Without guaranteeing full recovery, States strive to design a strategy that minimizes transition costs while according utilities the opportunity to recover stranded costs that were prudently incurred and are verifiable and non-mitigable. In the alternative, States may face non-cooperation from utilities, including legal challenges. Either of these developments can lengthen the proposed transition to a competitive market for power.

Key details on treatment of stranded costs in various States are included in Table 17. Additional details are provided in Appendix E.

Performance-Based Ratemaking (PBR)[114]

Under traditional cost-of-service, rate-of-return regulation, the price of electricity charged by a utility includes all of its variable and fixed costs plus a reasonable return on invested capital.[115] In this environment, there is little or no incentive to reduce costs by implementing either efficiency improvements or productivity enhancements, because such actions are not likely to improve profitability.[116] Economists contend that the cost-of-service regulatory approach produces inefficiencies in the choice of factor inputs, tending to make utilities more capital-intensive than they would be in a competitive environment. This distortion in the allocation of resources is known to economists as the *Averch-Johnson effect*.[117]

Performance-based ratemaking (PBR) represents an effort by regulators to decouple the linkage between utilities' prices and their costs under regulation by offering financial incentives to utilities to lower rates or costs.[118] Under PBR, good utility performance can be rewarded with higher profits and poor performance can be penalized in some manner. PBR may thus be viewed as an alternative to traditional ratemaking and as a variant of incentive regulation.[119] Some others view it as an evolutionary reform that is useful as the electricity generation sector transitions toward complete deregulation.[120]

PBR is not new, having been used extensively in the telecommunications and railroad industries.[121] The

[113] A utility's fixed costs are prone to decline over time. In addition, competitive pressures may lead to efficiency improvements. The impact of these two factors may lead to a possible reduction of stranded costs over time. In some cases, stranded costs may even become negative. L. Baxter, E. Hirst, and S. Hadley, *Transition Cost Issues for a Restructuring U.S. Electricity Industry* (Oak Ridge, TN: Oak Ridge National Laboratory, March 1997), pp. 67-74.

[114] This section is based on a recent study undertaken by Dr. Jeff Fang of the National Renewable Energy Laboratory with funding and direction from the Energy Information Administration. National Renewable Energy Laboratory, *Selected Topics in Electric Industry Restructuring* (Washington, DC, February 1998).

[115] Proposals regarding level and rate structure changes are submitted by utilities to State public utility commissions well in advance of their effective dates. State commissions may allow or disallow changes requested. Under certain conditions, commissions may also order a utility to change the level and structure of its rates. These proceedings, commonly known as rate cases, determine the rate of return a utility is authorized to earn. Since rate case proceedings are initiated only at discrete intervals, the actual rate of return a utility earns may be above or below the rate of return it is authorized to earn.

[116] Critics point out that utilities may inflate operations and maintenance costs, over- or underinvest, be slow to adopt changes in technology, and be saddled with inefficiencies in management and compliance costs. Taken together, these factors contribute to a loss of competitive power.

[117] A hypothesis developed by Averch and Johnson demonstrates that subjecting a profit-maximizing firm to an overall regulatory constraint on rate of return leads the firm to employ more capital and less labor (in a two-factor input industry) so that it can reap higher profits. This results in an inefficient allocation of resources. Refer to H. Averch and L.L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* (December 1962), pp. 1053-1069.

[118] The decoupling is done by decreasing the frequency of rate cases, employing external measures of cost for rate setting, or a combination of these two approaches. Refer to Lawrence Berkeley National Laboratory, *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues*, Volume I, LBL-37577 (Berkeley, CA, November 1995).

[119] Note that the terms "performance-based ratemaking" and "incentive regulation" are often used interchangeably to connote the same basic concepts.

[120] P. Navaro, "The Simple Analysis of Performance-Based Ratemaking: A Guide for PBR Regulator," *The Yale Journal of Regulation*, Vol. 13, No. 105 (1996), pp. 105-161.

[121] G.A. Comnes, S. Stoft, et al., "Six Useful Observations for Designers of PBR Plans," *Electricity Journal* (April 1996), pp. 16-23. A recent report prepared for the National Association of Regulatory Utility Commissioners points out that PBR, which is as old as utility regulation itself, has been in vogue since 1906. Refer to National Association of Regulatory Utility Commissioners, *Performance-Based Regulation in a Restructured Electric Industry*, report prepared by Synapse Energy Economics Inc. (Cambridge, MA, November 1997), pp. 12-14.

Table 17. Treatment of Stranded Costs by States as of April 30, 1998: A Summary

State	Order	Legislation	Proposed Start Date for Phased-in Retail Competition	Proposed Date for Full Retail Competition	Composition of Stranded Costs	Recovery Level Permitted	Recovery Mechanism	Procedure for Estimating Stranded Costs	Mitigation Requirement/ Strategies	Projected Recovery Period
Arizona	12/96 [a]	Legislation is required to implement this proposal.	January 1, 1999	January 1, 2003	Generation assets, purchased power agreements, fuel contracts, regulatory assets, employment transition costs, and environmental mandates.	Utilities have the opportunity to recover prudently incurred stranded costs.	No decision. Possible choices: variable charges, fixed fees, exit fees, access fees.	Administrative approach is recommended.	Required.	Recommended period is no longer than 10 years, beginning January 1999.
California	12/95 [b]	9/96 [c]	March 31, 1998 [d]	March 31, 1998	Generation assets, nuclear power plant settlements, power purchase agreements, qualifying facilities contracts, capital costs of early retirement and retraining programs.	Utilities have the opportunity to recover prudently incurred stranded costs. Nuclear stranded costs may be recovered.	Competitive transition charge (CTC). Utilities authorized to securitize $7.3 billion through issuance of rate reduction bonds.	Market-based approach.	Required.	Four years (through 12/31/01) for generation-related assets. Rate Reduction bond financing would mature 10 years from issue.
Connecticut		4/98 [e]	January 1, 2000	July 1, 2000	Generation assets, generation-related regulatory assets, long-term power purchase contract costs, and others.	Stranded cost recovery is based on the divestiture of all non-nuclear generating assets and aggressive implementation of mitigation strategies.	Recovery of stranded costs will be recouped through a competitive transition assessment (CTA) charge imposed on all customers of an electric distribution company. Utilities may also be authorized to issue rate reduction bonds (RRBs) for specific stranded costs.	The legislation provides a methodology to estimate stranded costs.	Stranded costs must be minimized through mitigation. All generation assets must be divested by 2004.	All RRBs are to be retired no later than December 31, 2011. CTA charges, beginning January 1, 2000, will be imposed until the RRBs are retired on or before December 31, 2011.
Illinois		12/97 [f]	October 1, 1999	May 1, 2002	Categories unspecified.	Opportunity for full recovery.	Transition charge and limited securitization.	Lost revenue approach.	Required. Level of mitigation is reflected in transition charge.	December 31, 2006.

See footnotes at end of table.

Table 17. Treatment of Stranded Costs by States as of April 30, 1998: A Summary (Continued)

State	Order	Legislation	Proposed Start Date for Phased-in Retail Competition	Proposed Date for Full Retail Competition	Composition of Stranded Costs	Recovery Level Permitted	Recovery Mechanism	Procedure for Estimating Stranded Costs	Mitigation Requirement/ Strategies	Projected Recovery Period
Maine		5/97 [g]	March 1, 2000	March 1, 2000	Above market costs associated with utility generation, generation-related contracts, and regulatory assets.	Opportunity for full recovery.	To be determined before the recovery period begins in March 2000.	Market value approach in the context of divestiture.	Generation-related assets must be divested by 2000.	Recovery period begins March 2000. Every 3 years actual stranded costs are trued up, and the recovery period ends when all stranded costs are paid.
Maryland	12/97 [h]	Legislative authority not required. However, the Commission will work with the legislature to craft legislation.	July 1, 2000	July 1, 2002	Unrecoverable capital costs of generating assets, regulatory assets, costs of restructuring, social and demand-side management programs. Excludes nuclear stranded costs.	Opportunity for full recovery.	Potential options include a competitive transition charge (wires charge) and exit fee. Securitization is encouraged if ratepayers benefit.	Market value approach recommended. Each utility to file plans with the Public Service Commission.	Divestiture of assets recommended.	Time frame for recovery to be included in filings by utilities.
Massachusetts	12/96 [i]	11/97 [j]	March 1, 1998	March 1, 1998	Utility-owned generation assets, purchased power contracts, regulatory assets, and nuclear decommissioning costs.	Opportunity for full recovery.	Direct access charge to be recovered by utilities subject to regulatory appproval. Securitization is permitted when utilities meet required conditions.	Administrative and/or market valuation with reconciliation methods.	Aggressive mitigation required. Full divestiture is not required, but encouraged.	Five to ten years with true-ups in years two, five, and ten.
Michigan	6/97 [k]	Legislation necessary to carry out plan proposed.	Phased-in retail competition begins March 31, 1998 (2.5 percent of load), with graduated annual increases of 2.5 percent through 2001, for a total of 12.5 percent available by January 1, 2002.	January 1, 2002	"Costs incurred during the regulated era that will be above market prices," encompassing five categories: (1) regulatory assets, (2) capital costs of nuclear plants, (3) contract capacity costs from power purchase agreements, (4) employee retraining costs, (5) costs of implementing restructuring.	Opportunity for recovery of prudently incurred costs.	Transition charge with potential securitization option.	Top-down administrative estimates subject to periodic true-ups.	Not mandated.	March 31, 1998-December 31, 2007.

See footnotes at end of table.

Table 17. Treatment of Stranded Costs by States as of April 30, 1998: A Summary (Continued)

State	Order	Legislation	Proposed Start Date for Phased-in Retail Competition	Proposed Date for Full Retail Competition	Composition of Stranded Costs	Recovery Level Permitted	Recovery Mechanism	Procedure for Estimating Stranded Costs	Mitigation Requirement/ Strategies	Projected Recovery Period
Montana		5/97 [l]	July 1, 1998	July 1, 2002	Above market costs of qualifying facility contracts, energy supply related regulatory assets and deferred charges, investor-owned utility generation, and power purchase contracts.	Opportunity to recover prudently incurred costs.	Nonbypassable transition charge. Securitization to recover certain transition costs is authorized.	Based on review of utility filings due one year before direct access.	Required.	July 1, 1998 - July 1, 2002.
Nevada		6/97 [s]	December 31, 1999	December 31, 1999	Composition of stranded costs to be determined. Staff report [t] includes past generation investment and contractual obligations, regulatory assets, and public policy costs.	Opportunity to recover prudently incurred costs.	Commission to determine mechanism. Staff report suggests use of a nonbypassable access charge.	AB 366 directs the Commission to determine stranded costs.	Required.	AB 366 gives the Commission authority to determine the appropriate recovery period.
New Hampshire	2/97 [m]	5/96 [n]	January 1, 1998 [o]	January 1, 1998 [p]	Above market, sunk costs of utility-owned generating facilities, regulatory assets, above-market power purchase costs, and nuclear generating facility decommissioning costs.	Opportunity for recovery linked to the regional average electricity prices.	Nonbypassable transition charge. Securitization to be considered very carefully since it may reduce incentives for mitigation.	Divestiture of generation assets.	Aggressive mitigation required. Utilities to submit divestiture plans by 12/31/97.	To be negotiated with utilities.
New Jersey	4/97 [q]	Legislation needed to implement plan will be reviewed during the 1998 session of the New Jersey legislature.	October 1, 1998	July 1, 2000	Costs directly related to utility power supply, including utility generating plants, long- and short-term power purchase contracts with other utilities and with nonutility generators.	Opportunity for full recovery.	Market transition charge (MTC). Securitization is proposed.	Sale prices for divested assets will be the basis of stranded costs estimates.	Utilities must take all reasonable steps to mitigate nonutility generator contracts and other stranded costs.	Period lasts up to 8 years, through 2008.
New York	5/96 [r]	Legislation is needed to carry out plan.	1998	Contingent on settlement agreement with jurisdictional utilities in the State.	Above market generation assets, including nuclear power generating assets, nonutility generator contracts, regulatory assets, and others.	Full recovery not guaranteed. Recovery level varies with each individual utility agreement and depends on utility's mitigation efforts.	Nonbypassable access or wires charge. Securitization is proposed.	Estimates submitted by utilities subject to regulatory review and approval.	Required.	Negotiated on a utility-by-utility basis.

See footnotes at end of table.

Table 17. Treatment of Stranded Costs by States as of April 30, 1998: A Summary (Continued)

State	Order	Legislation	Proposed Start Date for Phased-in Retail Competition	Proposed Date for Full Retail Competition	Composition of Stranded Costs	Recovery Level Permitted	Recovery Mechanism	Procedure for Estimating Stranded Costs	Mitigation Requirement/ Strategies	Projected Recovery Period
Oklahoma		4/97 [u]	July 1, 2002	July 1, 2002	Long-term investments and contractual obligations.	Opportunity to recover prudently incurred stranded costs.	Nonbypassable transition charge.	Commission to determine.	Not spefically required in SB 500. Mitigation to be discussed in financial issues recommendation due to legislature December 1999.	Three to seven years.
Pennsylvania		12/96 [v]	January 1, 1999	January 1, 2001	Regulatory assets, buyout costs for uneconomic qualifying facilities contracts, above market costs of existing generating facilities including their retirement costs, unfunded portion of projected nuclear generating plant decommissioning costs, and other transition costs.	Opportunity to recover prudently incurred stranded costs.	Nonbypassable customer bill surcharge. Securitization allowed.	Utility filings to be reviewed on a case-by-case basis.	Required.	Recovery began January 1, 1997, and will last approximately 9 years. The recovery period can be shortened or lengthened in agreements with individual utilities.
Rhode Island		8/96 [w]	July 1, 1997	July 1, 1998	Costs associated with power purchase contracts, regulatory assets, and net unrecovered costs of generating plants.	Opportunity for recovery of prudently incurred costs.	Nonbypassable transition charge, initially set at $2.8 cents per kilowatthour. RI Assembly passed securitization bill.	By 2001, 15% of generation assets must be sold, allowing valuation. A true-up process will be used to track the proceeds of transition charge.	Required. Partial divestiture required.	Twelve years (by December 31, 2009).
Vermont	12/96 [x]	Legislative action is needed to implement this plan. Legislation was introduced in 1997, but measure did not pass.	January 1, 1998	December 31, 1998	Generation assets, power purchase agreements, and regulatory assets (which include nuclear decommissioning costs and demand-side management program costs).	Recovery level linked to strength of mitigation strategies.	Nonbypassable competitive transition charge. Securitization is under consideration.	"Bottom up" administrative approach. Utilities submit estimates, and each claim will be balanced with potential mitigation techniques.	Required.	Three years (by December 31, 2001).

See footnotes at end of table.

Table 17. Treatment of Stranded Costs by States as of April 30, 1998: A Summary (Continued)

State	Order	Legislation	Proposed Start Date for Phased-in Retail Competition	Proposed Date for Full Retail Competition	Composition of Stranded Costs	Recovery Level Permitted	Recovery Mechanism	Procedure for Estimating Stranded Costs	Mitigation Requirement/ Strategies	Projected Recovery Period
Virginia		4/98 [y]	January 1, 2002	January 1, 2004	Not specified, to be decided by State Corporation Commission and future legislation.	Just and reasonable net stranded costs will be recoverable, and appropriate consumer safeguards related to stranded costs will be implemented.	Not specified, to be decided by State Corporation Commission and future legislation.	Not specified, to be decided by State Corporation Commission and future legislation.	Not specified, to be decided by State Corporation Commission and future legislation.	Not specified, to be decided by State Corporation Commission and future legislation.

[a] Arizona Corporation Commission, Docket No. U-0000-94-165, Decision No. 59943, *In the Matter of the Competition in the Provision of Electric Services Throughout the State of Arizona* (December 26, 1996).
[b] California Public Utilities Commission, Case No. R-94-04-31, Decision 95-12-063, *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation* (December 20, 1995).
[c] California Civil Code Chapter 845, Assembly Bill 1890, *An Act Related to Public Utilities* (September 23, 1996).
[d] January 1, 1998, was initially proposed for implementation of competition at the retail level. Due to operational problems, the date has been moved to March 31, 1998. California Public Utilities Commission, Case No. R-04-31, Decision No. 97-12-131, *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation* (December 30, 1997).
[e] Connecticut House Bill 5005, Public Act No. 98-28, *An Act Concerning Electric Restructuring* (April 29, 1998).
[F] Illinois law, Article 16, HB 362, *Electric Service Customer Choice and Rate Relief Law of 1997* (December 16, 1997).
[g] State of Maine, H.P. 1274-L.D. 1804, *An Act to Restructure the State's Electric Industry* (May 29, 1997).
[h] Maryland Public Service Commission, Order No. 73834, Case No. 8738, *In the Matter of the Commission's Inquiry Into the Provision and Regulation of Electric Service* (December 3, 1997). The following order delays the initial start date of April 1999 to July 2000: Maryland Public Service Commission, Case No. 8738, Order No. 73901, *In the Matter of the Commission's Inquiry Into the Provision and Regulation of Electric Service* (December 31, 1997).
[i] Massachusetts Department of Telecommunications and Energy (formerly Department of Public Utilities), Decision 96-100, *Electric Industry Restructuring Plan: Model Rules and Legislative Proposal* (December 30, 1996).
[j] State of Massachusetts, HB 5117, *Bill Relative to Restructuring the Electric Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protection Therein* (November 25, 1997).
[k] Michigan Public Service Commission, Case No. U-11290, Opinion and Order, *In the Matter, on the Commission's Own Motion to Consider the Restructuring of the Electric Utility Industry* (June 5, 1997). This order was later amended by a January 14, 1998, order under the same docket number. The revised order delayed the starting date for retail competition.
[l] Montana Senate Bill 390, *The Montana Electric Utility Industry Restructuring and Consumer Choice Act* (May 27, 1997).
[m] New Hampshire Public Utilities Commission, Docket No. 96-150, *Restructuring New Hampshire's Electric Utility Industry: Final Plan*, (February 28, 1997).
[n] New Hampshire House Bill 1392 (RSA Chapter 374-F), *An Act Restructuring the Electric Utility Industry in New Hampshire and Establishing a Legislative Oversight Committee*, was enacted on May 16, 1996, to be effective from May 21, 1996.
[o] The New Hampshire PUC shifted the target date for beginning retail choice from the initial target of January 1, 1998, to July 1, 1998, due to delays resulting from litigation with Public Service Company of New Hampshire. The July start date may be further postponed, since the litigation with PSNH will be heard November 1998.
[p] *Ibid.*
[q] New Jersey Board of Public Utilities, Docket No. EX94120585Y, *Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations* (April 30, 1997), p. 2.
[r] New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service, Opinion and Order* (May 20, 1996).
[s] Nevada Assembly Bill 366, *An Act Relating to Governmental Administration* (July 14, 1997).
[t] State of Nevada Public Service Commission, *The Structure of Nevada's Electric Industry: Promoting the Public Interest* (June 1996).
[u] Oklahoma Assembly Bill 500, *Electric Restructuring Act of 1997* (April 25, 1997).
[v] Pennsylvania House Bill 1509, Sections 3-4, Title 66 Pennsylvania Consolidated Statutes, Sections 2801-2812, *The Electricity Generation Customer Choice and Competition Act* (December 31, 1997).
[w] Rhode Island Assembly Bill 96-H 8124B, *An Act Relating to the Utility Restructuring Act of 1996* (August 7, 1996).
[x] Vermont Public Service Board, Docket No. 5854, *Investigation Into the Restructuring of the Electric Utility Industry in Vermont. The Power to Choose: A Plan to Provide Customer Choice of Electricity Suppliers*, Report and Order (December 31, 1996).
[y] Virginia Acts of Assembly, HB 1172, *An Act to Establish a Schedule for Virginia's Transition to Retail Competition in the Electric Industry*, Effective July 1, 1998.
Source: Energy Information Administration.

current revival of interest in PBR is due to its capability to provide incentives that are similar to those provided by competition.[122] PBR also permits participants to secure a share of the gains (profits) resulting from improvements in efficiency or gains in productivity. In addition, the implementation of PBR can potentially assist State regulators during the restructuring process by complementing some of the incentives created by competition, or by removing some of the obstacles to customer choice.[123]

PBR can be tailored to meet different objectives. During the transition to competition in generation, the central objective is to provide customers with lower rates without any diminution in safety, reliability, or quality of service.[124] To meet this objective, the regulators set a starting point or "baseline" revenue requirement, which can be adjusted (up for inflation or down for efficiency improvements). A package of incentives is then proposed to permit the utility to lower its costs relative to the baseline costs, in which case the realized cost savings are divided between the customers and the equity holders. Implementation hinges on quality control requirements that preclude cost savings at the expense of system reliability or customer service.[125]

Approaches to PBR

It is possible to devise different approaches to tailor PBR mechanisms.[126] For the most part, these varying approaches can be collapsed into three principal categories: price caps, revenue caps, and sliding scale mechanisms. Note that these approaches are widely known and have been used in the past with respect to electric utilities.[127]

Price Cap

Under the price cap approach, a ceiling price is set by regulatory authorities for a specified period into the future.[128] The initial price is set in a manner similar to that of traditional cost-of-service rates.[129] The utility is then allowed the flexibility to set prices below the ceiling without having to seek approval from the regulatory

[122] Besides setting utility rates, PBR has also been used "to lower fuel costs, encourage conservation, increase resource mix diversity, improve capacity factors and heat rates, reduce pollution, and reward good management practices." P. Navaro, "The Simple Analysis of Performance-Based Ratemaking: A Guide for PBR Regulator," *The Yale Journal of Regulation*, Vol. 13, No. 105 (1996).

[123] National Association of Regulatory Utility Commissioners, *Performance-Based Regulation in a Restructured Electric Industry*, report prepared by Synapse Energy Economics Inc. (Cambridge, MA, November 1997), p. 4.

[124] Other objectives may include promoting conservation mechanisms or the promotion of renewable technologies. An additional listing of objectives can be found in T. Woolf and J. Michals, "Performance-Based Ratemaking: Opportunities and Risks in Competitive Electricity Industry," *Electricity Journal* (October 1995), pp. 64-73.

[125] A simple model can be used to present the basics of performance-based ratemaking and incentive regulation. Consider the relationship:

$$\text{Revenues} = a + b * \text{Costs}$$

where:

Revenues	=	actual (*ex post*) revenues received
a	=	fixed payment, set *ex ante*
b	=	*ex ante* sharing fraction, $0<b<1$
Costs	=	*ex post* costs

Economists contend that "a firm's incentive to minimize costs is inversely proportional to the magnitude of the sharing fraction b. In other words, a firm's risk for cost overruns and its ability to keep any costs savings increase as b decreases." For additional discussion of this approach, see Lawrence Berkeley National Laboratory, *Performance-Based Rate Making for Electric Utilities: Review of Plans and Analysis of Economics and Resource Planning Issues*, Vol. I, LBL-37577 (Berkeley, CA, November 1995), p. 3.

[126] The description in this section is based on L.J. Hill, *A Primer on Incentive Regulation for Electric Utilities*, ORNL/CON-422 (Oak Ridge, TN: Oak Ridge National Laboratory, October 1995). See also, Lawrence Berkeley National Laboratory, *Performance-Based Rate Making for Electric Utilities: Review of Plans and Analysis of Economics and Resource Planning Issues*, Vol. I, LBL-37577 (Berkeley, CA, November 1995).

[127] For an excellent discussion of the role of incentive regulation (prior to the start of current restructuring initiatives), refer to P.L. Joskow and R. Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation*, Vol. 4, No. 1 (1986), pp. 1-49. This article also contains a summary of incentive programs initiated in States during the late 1970s and early 1980s.

[128] The period for which the cap will remain in operation is sufficiently long so as to preclude the possibility that utilities will file rate cases frequently. Note that during the 1970s, rate cases were more frequent and that automatic adjustment clauses for fuel costs were critically important.

[129] Prices under regulation are based on cost of service. They also tend to be inflexible. Since the cost-price relationship and the inflexibility are concerns, the real challenge is to develop a mechanism that does not adhere to a correspondence between prices and costs as is normally done in cost-of-service regulation. Refer to Oak Ridge National Laboratory, *A Primer on Incentive Regulation for Electric Utilities*, ORNL/CON-422 (Oak Ridge, TN, October 1995), pp. 7-11.

authority. There is also some predetermined price floor, such as the short-run or the long-run marginal costs of providing the service. This approach enables the utility to reap all the benefits of cost reductions while also bearing the cost of upward deviations between the target and the actual cost.

Once the initial price is set, the ceiling price over time is indexed to changes in inflation less an allowance for productivity improvements. The changes in productivity are sometimes referred to as the "X" factor. In some cases, unanticipated changes in costs not under the control of the utility are allowed to be included in the changes in the ceiling. In the literature on incentive regulation, such changes are called the exogenous factor, or the "Z" factor. Examples of the Z factor include regulatory assets such as deferred investment, expenditures associated with low-income programs, and in some cases, research and development (R&D) costs.[130]

A utility has two incentives to reduce costs under this approach. First, after the initial ceiling price is determined, any reduction in costs will increase the profits of the utility until the end of the PBR period. Second, the period for which the price ceiling is applicable is much longer than the period between rate cases under traditional cost-of-service ratemaking; it is typically three years or more. The infrequency of regulatory reviews again serves to induce the utility to reduce costs, because the utility can keep the additional profits realized from cost reductions without triggering regulatory review during the period.

The inflation rate can be measured through the changes in the consumer price index (CPI), wholesale price, gross domestic product deflators, or an index of electric utility input prices. Productivity changes can be measured with the Bureau of Labor Statistics factor productivity index for the U.S. economy. Sometimes, changes in the productivity of the electric utility are taken into account: the productivity factor is measured as the difference between the national productivity measure and the electric industry productivity growth measure.

Revenue Cap

Under the revenue cap approach, regulatory authorities cap a utility's allowed revenues instead of prices. The cap permits adjustments for customer growth, but it is subjected to an index that takes price and productivity changes into account in computing the revenues allowed for a given time period. The discussion in the preceding section with regard to adjustments for inflation, productivity increases, and the Z factor is also applicable to the revenue cap formulation.

A cap may be applied to revenues in the aggregate or may be associated with revenues on a per customer basis.[131] In the former case, there is an incentive for the utility to expand its electricity sales, assuming that rates are higher than marginal costs. In the latter case, there is an incentive for the utility to reduce its sales per customer. In this sense, the revenue cap is conducive to the promotion of energy efficiency and demand-side management programs.

Some features of revenue caps can decrease their efficacy, objectivity, and simplicity. First, revenue caps may cover only a subset of utility revenues to the exclusion of other costs. Second, revenue caps may not cover the determination of final prices, making it possible for a utility firm to charge more than it could under monopoly conditions.[132] Third, it is possible "that a small reduction in revenue cap will produce a large

[130] In its most general form, the automatic adjustment of the ceiling price can be represented by the following equation:

$$P_{n,t} = P_{n,t-1} * (1 + I - (P_G - P_E) \pm Z)$$

where $P_{n,t}$ and $P_{n,t-1}$ are the ceiling prices for the n basket of goods in this year and last year, respectively; I is the inflation rate; P_G and P_E are productivity for the economy in general and for the electric utility respectively; and Z stands for the exogenous factors. When no distinction is made between the productivity of the economy in general and the electric utility industry, the $(P_G - P_E)$ term in the equation is replaced with a single productivity measure.

[131] The formula for adjusting the revenue ceiling can be expressed either in total revenue terms (equation a) or on a total revenue-per-customer basis (equation b):

(a) $REV_{n,t} = REV_{n,t-1} * (1 + I - P + G_t);$

(b) $(REV_{n,t} / CUST_{n,t}) = (REV_{n,t-1} / CUST_{n,t-1}) * (1 + I - P),$

where REV is total revenues; P=productivity; I=inflation; G=growth rate in sales; CUST=number of customers.

[132] M.A. Crew and P.R. Kleindorfer, "Price Caps and Revenue Caps: Incentives and Disincentives for Efficiency," in *Proceedings: Eighth Annual Seminar on Public Utility Regulation (Western Conference)* (San Diego, CA, July 1995).

and unpredictable reduction in price."[133] Finally, there is also the possibility that a revenue cap may promote incentives to reduce sales regardless of the social benefits.

Solutions to some of these problems can be found by using a hybrid price-revenue cap.[134] Overall, both the price and revenue cap approaches create incentives to reduce costs. Some studies maintain that the tendency to overinvest in capital goods (the Averch-Johnson effect) can also be eliminated, and that efficiency improvements can be achieved. However, these approaches differ significantly on the subject of promoting or restraining kilowatthour sales. There is a perceived tendency to increase sales under a price cap regime and to minimize sales under a revenue cap regulation. It is possible to eliminate these shortcomings by devising a hybrid system that incorporates parts of both approaches.

Sliding Scale[135]

Under a sliding-scale PBR, a utility's rates for electricity are determined in the traditional cost-of-service manner. However, the earned rate of return on equity is allowed to fluctuate within a specified limit (or a band) around an authorized rate. Electricity prices are adjusted—up or down—to enable the utility to attain its authorized rate of return.[136]

In implementing a sliding-scale PBR, the intent is to track annual earnings (i.e., rate of return) and to share with ratepayers when the returns fall outside the prescribed band. The sharing mechanisms remain inoperative during the period when the utility earns a rate of return within the band. Generally speaking, there is an incentive for the utility to earn a rate of return that is higher than its authorized rate. For this approach to succeed, the range in which rates can oscillate should be wide enough for the utility to seriously consider cost reductions. Problems can arise if the range (within which the rate fluctuations are permitted) is too narrow, in which case adjustments by regulatory authorities would tend to become frequent. This would lower the utility's incentive for reducing costs. For this reason, the sliding-scale PBR is always used in conjunction with a price or revenue cap approach.

Targeted Incentives

Another alternative is for regulatory authorities to target a specific aspect of a utility's operation and provide incentives to improve its cost performance in that specific area. The three components of this approach are: target of the program, the measurement norm, and the associated rewards or penalties.[137]

The performance of designated generating units (such as nuclear power plants) has historically been targeted in the past. Promoting investment in demand-side management programs has been another popular target. In selecting these or other targets, the standard against which performance is to be measured could be based on a utility's historical performance record, the performance of a group of utilities, or any other standard stipulated by the regulatory authorities. Reductions in costs could be passed to the utility. A criticism of this approach is that by focusing on one aspect of a utility's operation it may detract attention from a host of other areas that may also be candidates for improved performance.

[133] Lawrence Berkeley National Laboratory, *Performance-Based Rate Making for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues*, Vol. I, LBL-37577 (Berkeley, CA, November 1995), p. 81.

[134] *Ibid.*, p. 82. The study, however, points out that there are many questions pertaining to the use and application of revenue caps that remain unanswered.

[135] Variations of this PBR are the *rate-of-return bandwidth regulation* and the *earnings sharing mechanisms.* Lawrence Berkeley National Laboratory, *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning issues*, Vol. I, LBL-37577 (Berkeley, CA, November 1995).

[136] The automatic adjustment of the rate of return can be expressed as follows:

$$r_t = r_{t-1} - k * (r_{t-1} - r^*)$$

where r_t and r_{t-1} are the rate of return for years t and t-1, respectively; k is the sharing factor; and r^* is the authorized rate of return. Accordingly, during the period in which the authorized rate of return is in effect, the new authorized rate will be equal to the previous-year approved rate adjusted for the difference between last year's approved rate of return and the current approved rate of return. It will account for the sharing of benefits among shareholders and ratepayers. The sharing factor will be assigned a value of zero if the earned return is within the allowable band. As an example, assume that the utility can earn a rate of 1 percent more or less around an authorized rate of 10 percent. For any returns between 9 and 11 percent, k (the sharing factor) assumes the value of zero. For values that are either less than 9 or higher than 11, k may have an assigned value of 0.5. Refer to Oak Ridge National Laboratory, *A Primer on Incentive Regulation*, ORNL/CON-422 (Oak Ridge, TN, October 1995), pp. 12-13.

[137] *Ibid.*, p. 13.

PBR and Restructuring

With prospects of restructuring looming in many States, investor-owned utilities have a vested interest in actively participating in PBR programs, given the feasibility of reducing overall costs and improving their competitive edge (and possibly their profits) without having to confront the discipline of the market. Some State regulatory authorities support PBR as a measure that propels the industry toward efficiency and cost reduction without compromising the goals of safe, reliable, and least-cost service.[138] For example, the Massachusetts Department of Telecommunications and Energy (MDTE) lists five broad classes of benefits associated with incentive regulation: (1) improved X-efficiency, (2) improved allocative efficiency, (3) facilitation of new services, (4) reduced regulatory costs, and (5) reduced administrative costs.[139]

The formulation of restructuring plans is based on the premise that market forces should be allowed to replace regulation. Accordingly, PBR includes those segments in which fully competitive markets do not currently exist (as in the case of power generation) or are not likely to exist in the future (such as distribution and transmission services). State initiatives are, therefore, of interest in providing information where for one reason or the other, implementation of restructuring may not be feasible in the near term. A brief overview of PBR plans that have been implemented in selected States is provided below.[140]

Massachusetts[141]

In September 1994, the Department of Public Utilities—currently called the Massachusetts Department of Telecommunications and Energy (MDTE)—initiated proceedings to investigate whether the implementation of PBR (or incentive regulation) would provide marketplace benefits to customers by promoting more efficient utility operations, cost control, and opportunities for reduced rates in the State. In addition, the MDTE intended to explore whether incentive regulation could improve upon the existing regulatory framework (as prevailing in the State) and accommodate the transition to competition.[142]

The MDTE sought comments on 19 questions in four basic categories: (1) theory and jurisdictional considerations, (2) broad-based versus narrowly targeted incentive programs, (3) effect of incentive regulation on the current regulation of utilities, and (4) procedural considerations concerning implementation. Its review indicated that a broad range of benefits (as indicated earlier) are associated with incentive regulation.[143]

The MDTE did not endorse or adopt a specific PBR mechanism, but instead indicated that it will review PBR proposals on a case-by-case basis. The utilities in the State were required to develop individual proposals based on well-defined standards and filing requirements. For this objective to be achieved, the MDTE provided the following evaluation criteria:[144]

- Be consistent with the Department's regulations, statutes, and governing precedents.
- Be consistent with market-based regulation and enhanced competition.
- Safeguard system integrity, reliability, and current policy objectives.

[138] Another study prepared for the National Association of Regulatory Utility Commissioners asserts that regulators can remove obstacles to effective customer choice in the following areas: mitigation of stranded costs, preparing for market realities, pricing flexibility, treatment of generation and purchased power, risk allocation, mergers, targeted incentives, nuclear power, and divestiture. The study discusses each of these benefits in modest detail. Refer to B. Biewald and T. Woolf, *Performance-Based Regulation in a Restructured Electric Industry* (Cambridge, MA: Synapse Energy Economics, Inc., November 1997), pp. 33-37.

[139] Massachusetts Department of Telecommunications and Energy, D.P.U. 94-158, *Investigation by the Department on Its Own Motion in the Theory and Implementation of Incentive Regulation for Electric and Gas Companies under Its Jurisdiction* (February 24, 1995), pp. 51-52. Note that X-efficiency is broadly defined as the degree to which a firm maximizes the production of goods and services with any given combination of inputs. This is commonly understood as "doing more with less."

[140] Note that most States in the process of restructuring have instituted PBR in some form. The examples presented here are illustrative of the activities undertaken by selected States.

[141] MDTE had initiated electric generating unit performance incentive as early as 1989, when it approved an incentive mechanism for Boston Edison's Pilgrim Nuclear Power Station as part of a three-year settlement agreement to resolve an open base rate proceeding and pending generating unit performance reviews. More recently, in 1993, the MDTE approved an incentive mechanism permitting benefits between customers and shareholders in the case of Boston Gas Company (D.P.U. 92-259).

[142] Massachusetts Department of Telecommunications and Energy, D.P.U. 94-156, *Investigation by the Department on Its Own Motion in the Theory and Implementation of Incentive Regulation for Electric and Gas Companies under Its Jurisdiction* (February 24, 1995).

[143] *Ibid.*, p. 10.

[144] *Ibid.*, pp. 56-65.

- Reward utility performance and address exogenous costs.
- Focus on comprehensive results.
- Incorporate well-defined, measurable indicators of performance.
- Be consistent with accounting standards and gain acceptance within the financial community.
- Allow the incentive plan enough time to succeed, within a minimum time frame.
- Reevaluate the program at least once during the period of the PBR to monitor goal attainment and make required modifications, as necessary.
- Be administratively simple.

The MDTE recognized that all incentive plans—and especially those that accord increased pricing facilities to utilities—must still be carefully designed. A plan must assign specific benefits that would additionally accrue to the customers either in the form of price or service. The plan should not permit the utility to cross-subsidize different customer classes or undertake anticompetitive behavior. In addition, the plan should hold a promise of higher financial rewards.

In a subsequent Order, the MDTE formulated a set of principles establishing the essential infrastructure of electricity restructuring in Massachusetts. Reiterating its earlier conclusions, one of these principles places reliance on incentive regulation where a fully competitive market cannot or does not exist. Recognizing that transmission and distribution will continue to be monopoly services requiring regulatory oversight, the MDTE directed that the utilities include a plan for incentive regulation for transmission and distribution systems in their respective restructuring plans.[145]

More recently, in a statement on restructuring and proposed rules (issued on May 1, 1996), the MDTE proposed that the distribution companies implement PBR in the form of price cap plans.[146] In the proposed PBR, base rates will be allowed to change annually based on inflation, with adjustments for productivity changes and other exogenous factors.[147] In addition, a distribution company will be penalized if it does not meet the specific (minimum) performance standards for safety, service reliability, and customer service.

Support for issuance of a price cap PBR was provided by several commenters,[148] who maintained that the price cap plans:

- Tracked the unit-cost trend of the utility
- Provided an effective mechanism for controlling rates during the transition period
- Provided customers with a predictable price trend that incorporated productivity and efficiency gains.

The MDTE directed that price cap PBR plans should be no less than 5 years in duration and should be evaluated at the end of that period. Distribution companies are to file their rate cap proposals for review at the same time that they file the first general rate case after the final industry restructuring rules become effective.

In submitting its final proposals, the MDTE reiterated its earlier conclusions that price cap plans are preferable to other types of PBR mechanisms and are more likely to achieved the desired objectives.[149] In directing the

[145] Massachusetts Department of Telecommunications and Energy (formerly Department of Public Utilities), Order No. D.P.U. 95-30, *Investigation by the Department of Public Utilities on Its Own Motion into Electricity Restructuring* (August 16, 1995), p. 27.

[146] This discussion is based on Massachusetts Department of Public Utilities, D.P.U. 96-100, *Statement and Proposed Rules, Investigation by the DPU upon Its Own Motion Commencing a Notice of Inquiry/Rulemaking, Establishing the Procedures To Be Followed in Electric Industry Restructuring by Electric Utilities* (May 1, 1996), pp. 71-76, and Appendix A, pp. A.8-A.11.

[147] The price cap formula is as follows:

$$PCI_{new} = PCI_{current} * (1 + P - X \pm Z).$$

PCI is the price cap index, which is initially set to be 1.0 and will be adjusted annually. P represents an inflation index. X represents the productivity offset, which will be either the productivity of the electric industry or the difference between the productivity of the U.S. economy and the electric industry. Z represents exogenous cost changes that are beyond the distribution company's control and are not captured in any other component of the price cap formula. The proponent of the Z-factor adjustment has the burden of proof to demonstrate that the specific changes are not captured in the P factor.

[148] Massachusetts Department of Telecommunications and Energy, D.P.U. 96-100, *Electric Industry Restructuring Plan: Model Rules and Legislative Proposal* (December 30, 1996), p. 111.

[149] *Ibid.*, Section VI. F.

utilities to include PBR proposals in their restructuring plans, the MDTE did not stipulate that a specific format (such as a price or a revenue cap) be followed in their submissions. However, it did provide three additional guidelines for preparing PBR plans:

- PBR plans should apply only to department-regulated functions at the time of filing.

- PBR plans should not involve the stranded cost issue, which will be addressed separately.

- Any proposal to convert a utility's distribution operations from cost-based to performance-based regulation should include comprehensive quality standards with significant financial incentives to guard against any degradation of traditional service quality and reliability levels.[150]

For example, a settlement reached by the affiliates of the New England Electric System (NEES) in February 1997 establishes performance-based rates.[151] Among other provisions, the settlement sets a floor of 6 percent and a ceiling of 11 percent on Massachusetts Electric's (NEES's affiliate) rate of return on equity, effective on commencement of retail choice in 1998. Earnings over the ceiling are to be shared equally between the customers and the shareholders, subject to a maximum of 12.5 percent, raising the effective cap on equity to 11.75 percent. In the event that earnings fall below the floor, a surcharge will be allowed to cover the shortfall. Rates for the distribution company of NEES were also set under the settlement.[152] Other provisions that affect Massachusetts Electric eliminate the adjustments for purchased power and freeze its non-fuel rates until 2001.

The July 1997 filing by Boston Edison Company adopts a somewhat different track. Its filing is an agreement (called a "settlement") reached with the State's Attorney General and the Governor's Energy Commissioner that has been submitted to the MDTE for approval. The settlement envisages PBR within the framework of a standard offer during the transition period from 1998 through 2004 and is contingent on full divestiture of the Company's generating assets, a rejuvenation of energy conservation programs, contributions to the "green" energy supplies, and a separation of its distribution and generation facilities.[153]

During the transition period, Boston Edison's customers will receive a 10-percent price reduction. Equity returns on its distribution operations have a ceiling of 11 percent and a floor of 6 percent, with provisions for adjustment if returns fall below the floor or exceed the ceiling. Boston Edison's delivery business will purchase power from other suppliers to implement the proposed 10-percent reduction.

Maine

Although PBR activities in Maine precede the recent restructuring efforts, they have not been very successful. The State's largest utility—Central Maine Power Company (CMP)—had seen its rates rise annually by about 10 percent during the period from 1990 through 1992. Bangor Hydro-Electric Company (BHE) needed pricing flexibility to be able to compete successfully in the State. Maine Public Service Company (MPS) was facing substantial financial stress. In response to these issues, the Maine Public Utilities Commission (MPUC or the Commission) crafted variants of PBR to suit the specific needs of each utility.[154]

In the case of CMP, the Commission devised an alternative rate plan (ARP) in an attempt to counter the utility's frequent request for rate increases and to mirror the effects of competition consistent with the commitment to serve the public interest. The Commission's solution in the form of an ARP imposed a price cap on CMP's operations for a 5-year period from 1995 through 1999.[155]

[150] *Ibid.*, p. 113.

[151] Note that the NEES and Eastern Edison Company had submitted their filings for settlement earlier. Boston Edison filed its electric restructuring plans in July 1997.

[152] Securities and Exchange Commission, New England Electric System 10-K report (March 1996).

[153] Boston Edison Co, *Restructuring Settlement Agreement* filed with the Massachusetts Department of Public Utilities on July 9, 1997. (Note that the Department is now known as the Department of Telecommunications and Energy.) The filing was in response to the directives contained in D.P.U. Docket Nos. 96-100 and 96-23.

[154] Maine Public Utilities Commission, Docket No. 92-345 (II), *Central Maine Power: Alternative Rate Plan (ARP)* (January 10, 1995); Docket No. 94-125, *Investigation of Flexible Pricing for Bangor Hydro-Electric Company: Alternative Marketing Plan (AMP)* (February 14, 1995); and Docket No. 95-052, *Maine Public Service-Rate Stability Plan (RSP)* (November 30, 1995).

[155] According to the Commission, a multiyear plan provides many benefits: electricity prices continue to be regulated in a predictable manner, rate predictability and stability become more likely, regulatory administrative costs are reduced, risks can be shifted away to shareholders, and efficiency improvements can bring about improvements in profitability.

Critical elements of the ARP include:

- Stipulation of a price cap ceiling with profit sharing and price flexibility. The price cap applies to all retail rates, including fuel and purchased power costs of the utility. The profit sharing mechanism adjusts earnings if they are outside a 350-basis-point bandwidth (currently at 7.05 percent to 14.05 percent) around the authorized cost of equity initially set at 10.55 percent.[156]

- Development in detail of a price cap formula, including a price index, a productivity offset, a profit-sharing mechanism, sharing benefits from buyouts of power purchase contracts pertaining to qualified facilities, flowthrough items, and recognition of mandated costs.[157]

- Empowerment of the utility to set flexible rates for its different customer classes in a manner designated by the Commission. Customer classes include existing customer classes, new customer classes for optional targeted services, and special rate contracts. The utility is thus better positioned to meet competition from other sources.[158]

- Establishment of a customer service and reliability index to give the utility incentive to adhere to specified benchmarks without invoking penalties that would otherwise become applicable.

- Fixed targets for demand-side management activities, with penalties for noncompliance.

- Delineation of various accounting provisions for regulatory assets, decommissioning costs, and other items.

The ARP provisions also protect the utility and its ratepayers against the consequences of adverse operating results on earnings. To evaluate this aspect, the MPUC will conduct a mid-term and a final review should returns fall outside a designated range.[159] The basic components of the ARP are designed to give CMP the incentive to reduce costs or to risk reduced rates of return on its equity.

The above critical elements of the ARP plan make it a major reform, even though the Commission's oversight continues. Note that the ARP has not fully protected the shareholders from the costs of the Maine Yankee nuclear power plant outage. In 1995, primarily as a result of the outage, the rate of return on equity was 5.7 percent. This loss was equally shared by the ratepayers and the shareholders and prompted the Commission to make adjustments for the mid-point rate of return on equity in its 1997 review. Since Maine Yankee's outage costs could also affect the utility in the future, the Commission could also direct that the utility divest its interests in Maine Yankee.[160]

The Commission's PBR for BHE also represents a form of price cap, although it is known as an "alternate marketing plan" (AMP). While the CMP's alternative rate plan focused on a price cap to force the utility to be more efficient, BHE's proposal sought increased flexibility to offer reduced prices and develop related marketing programs. More specifically, BHE sought discretion to reduce any of its rates without approval from the MPUC, subject to the criterion that such prices will be above the utility's short-run marginal costs plus 10 percent depending on circumstances. BHE provided a commitment to attempt to cap electric rates for an extended time period and to eliminate fuel cost accounting, the fuel adjustment clause, and seasonal rate differentials, together with an understanding about the method of amortizing the cost of any future buyout of high-cost purchased power contracts. In addition, the BHE plans also provided a voluntary commitment to avoid traditional rate increases to the extent possible.[161]

In approving BHE's request, the MPUC directed the utility to file interim marginal cost floors. Various stakeholders could request a proceeding with regard to setting permanent marginal cost floors. The MPUC also

[156] The Commission provided for a 50/50 sharing of profits or losses outside the 350-basis-point bandwidth (plus or minus) between the ratepayers and the shareholders. The bandwidth is wide enough to ensure that only extreme swings in earnings will be shared. It follows that, for oscillations in earnings within the bandwidth, the shareholder will bear the resulting gains or losses within the bandwidth.

[157] The inflation index is reduced by the sum of two productivity factors: a general productivity offset and a second formula-based offset to reflect the effect of inflation on power purchase costs during the currency of the ARP.

[158] This argument does not take into account other operational constraints that the utility may encounter.

[159] CMP's filing for the mid-term in 1997 did not seek any significant changes to the ARP. The MPUC did, however, make modest changes in parameters for pricing flexibility and in increasing the mid-point return on equity in June 1997. Refer to Central Maine Power Company, Quarterly Report (Form 10-Q) submitted to the Securities and Exchange Commission for the period ending June 30, 1997.

[160] For a further discussion on this issue, refer to National Association of Regulatory Utility Commissioners, *Performance-Based Regulation in a Restructured Electric Industry* (Cambridge, MA: Synapse Energy Economics, Inc., November 1997), pp. 18-20.

[161] Bangor Hydro-Electric Company, *1996 Annual Report* (March 19, 1997), p. 35.

encouraged affected stakeholders to resolve various issues arising from the implementation of the AMP.[162]

The third utility in the State, the MPS, also filed a proposed increase in rates and an alternative rate stability plan (RSP), in which it sought to collect increases in rates over a 5-year period. MPS filed a marginal cost study in support of its rate design proposal. The utility's filing was prompted by the loss of its two large customers and the costs of operations at Maine Yankee nuclear power plant.

In its stipulation, the MPUC established a multi-year rate plan that permitted the utility to increase its rates by an agreed-upon percentage. The Commission also established a profit sharing mechanism (with a target rate of return on utility's equity set at 11 percent), so that risks and benefits could be shared by the utility's shareholders and its customers.[163]

California

California's initial experience with incentive-based ratemaking started with the telecommunications industry in 1989 and then continued with the natural gas industry in 1991. In 1993, the California Public Utilities Commission (CPUC) recommended the use of performance-based ratemaking mechanisms as a possible tool to reform the regulatory process in the electric utility industry in the State.[164] CPUC's interest in replacing the traditional cost-of-service ratemaking with PBR was also prompted by the prevalence of electric rates in the State that were significantly higher than the national average.

With the commencement of investigations and rulemaking to consider the proposed restructuring of the electric utility industry in the State, the CPUC in its *Blue Book Decision* stated its objective of replacing the traditional cost-of-service regulation with PBR where competition had not yet developed.[165] While several factors contributed to this decision, the most critical was the high cost of electric services in the State.[166]

In its subsequent *Preferred Policy Decision,* the CPUC reaffirmed its commitment to continue support for PBR on grounds of encouraging efficient operation and improving productivity to replace the reasonableness reviews and disallowances associated with traditional rate case proceedings.[167] While utility services not subject to competition will continue to be regulated by the CPUC, PBR instead of cost-of-service regulation will be used to give utilities greater flexibility in running their operations. To meet this objective, the State's investor-owned utilities were directed to provide their comments on pending PBR proposals and to file new PBR applications subject to the unbundling of traditional utility services into generation, transmission, and distribution.

The *Preferred Policy Decision* notes that, as the market structure for the industry continues to be transformed, utility distribution services and utility-owned generation may be only two areas of continued regulatory oversight. A distribution PBR will focus on performance, so that customers can secure nondiscriminatory service without loss of quality. A generation PBR would be consistent with the assumption that utilities will retain some of their generating assets during the transition period. CPUC's subsequent *Roadmap Decision* delineated major issues to be taken up for discussion in crafting major PBR mechanisms.[168]

Even as the above policy decisions were being articulated and reaffirmed, utilities in California had already filed applications for approval of self-designed PBR plans. San Diego Gas and Electric, for example, filed its application proposing a base rate PBR in October 1992, followed by Pacific Gas and Electric in December 1992. Southern California Edison filed its PBR application (modified later to include only its transmission and distribution activities) in December 1993.

[162] Maine Public Utilities Commission, Docket No. 94-125, *Investigation of Flexible Pricing for Bangor Hydro-Electric Company: Alternative Marketing Plan (AMP)* (February 14, 1995).

[163] Maine Public Utilities Commission, Docket No. 95-052, *Maine Public Service: Rate Stability Plan* (November 30, 1995).

[164] California Public Utilities Commission, *Electric and Gas Utility Performance Based Ratemaking Mechanisms* (December 1997).

[165] California Public Utilities Commission, Docket No 94-04-032, *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation* (April 24, 1994).

[166] *Ibid.*, pp. 34-36.

[167] California Public Utilities Commission, Decision 95-12-063 (December 20, 1995) as modified by Decision 96-01-009 (January 10, 1996), *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation* (January 10, 1996).

[168] Major issues include: existing PBRs, establishing new PBRs for reactive power/voltage control, establishing new PBRs for distribution, Diablo/Palo Verde ratemaking proposals, and interaction with transition costs, hydro and geothermal assets. California Public Utilities Commission, Decision 96-03-022, *The Roadmap Decision* (March 14, 1996).

A recently released Commission study[169] points out that the base rate PBR plans so far adopted have the following main elements:

- A formula to establish revenue requirements indexed to inflation and adjusted for productivity and changes in cost of capital
- A revenue sharing mechanism allowing shareholders and ratepayers to share any actual revenues that exceed the authorized rate of return on equity
- A reward/penalty system to ensure that employee safety, reliability, and customer satisfaction standards are maintained
- Inclusion of adjustments to capture the influence of exogenous factors
- A monitoring and evaluation program.

As stated earlier, Southern California Edison (SCE) filed for a PBR mechanism in 1993 to determine most of its revenues.[170] SCE subsequently divided its filing between transmission and distribution and power generation (i.e., between generation and nongeneration revenues).[171]

The CPUC adopted a nongeneration (i.e., transmission and distribution) PBR mechanism for SCE in September 1996, to become effective on January 1, 1997.[172] Beginning in 1998, the PBR will be applicable only to the nongeneration distribution activities of the utility for the period ending in December 2001.

Key elements of the PBR as applicable to transmission and distribution include a rate indexing formula that takes into account inflation adjusted for productivity enhancements, a revenue sharing mechanism, a cost of capital trigger mechanism, service quality performance incentives, and adjustments for exogenous factors that are not within SCE's control. CPUC has also stipulated safety and safeguard standards that the Company must meet to ensure that costs are not reduced at the expense of safety or quality of service.

The base rate PBR filing by San Diego Gas and Electric Company (SDG&E) in 1992 was adopted by the CPUC in August 1994 for a term from 1994 through 1999.[173] This PBR is currently applicable to bundled electric service, including generation, transmission, and distribution and gas department base rate revenues.

The utility's PBR has four main components: a revenue cap based on formulas for developing an annual revenue requirement, a revenue sharing procedure, performance indicators, and a program to monitor and evaluate the program.[174] Provisions for suspending the PBR mechanism are also specified in the PBR, depending on whether the rate of return exceeds or falls below the authorized level for a given year.

SDG&E is required to file an annual report providing a summary of the prior year's performance on May 15th of each year.[175] Each year, the CPUC adjusts the revenue cap on the basis of the prior year's cap adjusted for inflation and customer growth, an offset for productivity, and changes in capital costs. Overall, the utility's experience with the PBR has been found to be successful in the area of performance, as evidenced by the awards it has received.

[169] California Public Utilities Commission, Energy Division, *Electric and Gas Utility Performance Based Ratemaking Mechanisms* (December 1997).

[170] California Public Utilities Commission, *Application of Southern California Edison Company to Adopt a Performance Based Ratemaking Mechanism Effective January 1, 1995*, Decision 96-09-092 (September 20, 1996).

[171] According to the SCE, power generation ratemaking was assigned to other mechanisms. Subsequently, SCE filed a PBR proposal covering its hydroelectric facilities and some fossil plants in 1996.

[172] California Public Utilities Commission, Decision No. 96-09-092, *Application of Southern California Edison Company to Adopt a Performance Based Ratemaking Mechanism Effective January 1, 1995*, Application No. 93-12-029 (September 20, 1996). This Decision requires that the SCE separate its transmission portion from the nongeneration PBR beginning 1998. This action was taken so that any directives by the Federal Energy Regulatory Commission could be complied with.

[173] California Public Utilities Commission, Decision No. 94-08-023 (August 3, 1994) and Energy Division's Resolution E-3512 (December 16, 1997).

[174] California Public Utilities Commission, Energy Division, *Electric and Gas Utility Performance Based Ratemaking Mechanisms* (December 1997).

[175] The utility has filed three annual performance reports for the years 1994, 1995, and 1996. In addition, it has also filed a 1997 summary of the past 3 years' experience. The CPUC's mid-term review of the utility's PBR, conducted since December 1996, has since been terminated together with the elimination of the need for a general rate case hearing in 1999. California Public Utilities Commission, Energy Division Resolution E-3512 (December 16, 1997).

Critics, however, fault the utility's price performance as being ineffective due to the design of the initial PBR.[176] Criticism has also been voiced regarding the manner in which profit sharing has operated in the past. Both these aspects are under review, and steps are being taken to remedy the profit sharing mechanism so that customers receive a reasonable share of the financial benefits resulting from operation of the PBR.[177]

As stated earlier, the *Preferred Policy Decision* directed all utilities in the State to establish generation and distribution PBR plans consistent with the policies outlined in the Decision.[178] In the case of SDG&E, the CPUC authorized continuance of the utility's PBR plan until the transition to a new industry has occurred. The utility is thus to file an electric distribution (and a gas department) PBR.[179] SDG&E filed its electric PBR in December 1997.

The CPUC adopted Pacific Gas and Electric Company's (PG&E) "base rate" PBR in 1993. Under this PBR, PG&E's annual price changes for electricity are based on a cost escalation index offset by productivity gains. Price changes that do not exceed an upper bound (based on a national average) are permitted. Based on the PBR's methodology, PG&E was eligible for a 2.4-percent price increase in 1995. The utility, however, requested a 1.5-percent increase in view of the changing industry conditions.

In July 1996, PG&E filed a PBR application for electric generation services applying only to its hydroelectric and geothermal plants (excluding fossil-fuel plants).[180] The PBR would set revenue requirements for base revenues (including sunk costs) and energy-related costs by using an indexed base revenue formula, with adjustments for shared earnings, fuel costs, performance standards, and extraordinary costs or savings.

PG&E also submitted a preliminary unbundling proposal in July 1996.[181] This proposal separates electric costs into five basic components: generation, competition transition charge, transmission, distribution, and public purpose programs. PG&E received authorization to file its distribution PBR proposal on or after December 15, 1997.[182]

Other States

This discussion deals with the recent experience of three States with respect to their PBR plans.[183] As other States finalize or move ahead in planning industry restructuring, the use of PBR programs may increase to cover activities in areas still being regulated. The Rhode Island restructuring legislation, for example, requires distribution companies to file PBR plans before December 1998.[184] The Michigan Public Service Commission has also expressed its full support for PBR

[176] Note that electric rates have been frozen in California since January 1, 1997. As a result, the electric price comparison component of the PBR has since been suspended by the CPUC, leaving the other components of the PBR in effect. All utilities in the State have been directed to file applications in January 1999 proposing ratemaking mechanisms which they believe should be in place at the end of the rate freeze period. California Public Utilities Commission, Decision No. 97-10-057 (October 22, 1997).

[177] On the subject of revenue sharing, the Energy Division of the CPUC recently noted that during the 3 years since the start of the PBR, SDG&E shareholders have received benefit of over $90 million, while the ratepayers were allocated a benefit of $2.5 million. Concern was also expressed with the utility's nondisclosure of certain accounting changes that affected the utility's writeoff levels and the methodology used to calculate performance component awards. California Public Utility Commission, Energy Division Resolution E-3512 (December 16, 1997).

[178] The utilities were given an extension for the filing date until the Federal Energy Regulatory Commission provided further guidance on the separation of transmission and distribution functions.

[179] SDG&E's PBR requires that the utility file a general rate case for a 1999 test year. This requirement has been vacated by the CPUC in view of the directive that the utility file a distribution PBR plan.

[180] For fossil generation, PG&E requested that sunk costs be recovered directly through the competition transition charge (CTC) with components of rates consistent with CPUC's stated policy. PG&E also stated that a substantial portion of its generating plants will be divested or spun-off during the transition period. Revenues for some fossil units that may be needed to provide ancillary services to the independent system operator (ISO) should be calculated using the traditional cost-of-service approach. Other fossil plants not needed by the ISO would remain fully at risk subject to revenues being recovered from the power exchange. Sunk costs of all such plants would be recovered through the CTC.

[181] A final proposal was submitted in December 1996. California Public Utilities Commission, Decision No. 97-08-56 (August 1, 1997).

[182] Activities related to ratesetting issues that include PBRs and unbundling are still being discussed in California. Refer to California Public Utilities Commission, Decision No. 97-08-056 (August 1, 1997) and Decision No. 97-10-057 (October 22, 1997). The first decision resolves issues relating to the allocation of costs between the various functions of the utilities and also allocates revenues between customer classes within each function and establishes certain rate design principles. The second decision provides an interim opinion while addressing several issues related to streamlining electric utility tariffs and regulatory accounts. Several issues stemming from these Decisions await resolution.

[183] For a summary of electric utility PBR plans existing in 1995, refer to Lawrence Berkeley Laboratory, *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues, Vol. II: Appendices* (Berkeley, CA, November 1995).

[184] The Rhode Island Utility Restructuring Act of 1996 (H-8124 Substitute B3), enacted on August 7, 1996.

plans, even though it does not have proposals from any of its jurisdictional utilities.[185] Programs in some other States incorporate all the essential ingredients of PBR plans but are labeled differently.[186]

State regulators have tended to distance themselves from the traditional rulemaking methodology, promoting PBR to stress efficiency and performance by utilities. To the extent that this effort leads to a potential decline in rates in comparison with those that would otherwise have prevailed, implementation of PBR may be preferable to traditional cost-of-service, rate-of-return regulation. Additional benefits include achievement of allocative efficiency (resulting from pricing flexibility enjoyed by the utilities) and a potential saving in administrative and regulatory costs. The key to securing some or all of these benefits lies in using the PBR as a part of long-term strategy.

Potential pitfalls also exist in the implementation of PBR. If the regulatory focus is primarily on costs of generation and purchased power, other cost and quality of service issues may be overlooked. Provisions pertaining to sharing earnings or absorbing losses could well lead to a dilution of utility incentives. Monitoring and evaluation inadequacies could possibly lead to unintended results not in conformity with the spirit of PBR plans.

Given the short timeframe during which the PBR plans have been in effect, it is difficult to evaluate their impacts in a systematic manner. The lack of performance yardsticks (in acquisition and operation) makes it particularly difficult to measure the success of PRB initiatives overall. In cases where PBR plans incorporate the passthrough of social program costs—such as demand-side management or environmental controls—benefits could be offset by the expenses of the programs. Similar problems would arise in funding low-income programs.

As the electricity generation segment of the industry moves toward competition, the requirement to craft PBR plans for generation activities may gradually decline over time. Utilities will, however, expect revenues pertaining to their transmission and distribution activities on a cost-of-service basis. The extent to which the application of PBR in these segments would reduce costs remains to be seen.[187] Thus, the success of PBR will hinge primarily on its design and implementation to the extent that safety, service, and reliability issues are not compromised in the process.

Pilot Programs

Background

Pilot programs are controlled tests designed to mimic the realities of retail competition in electricity generation. Pilot programs give a selected number of a utility's retail customers the option to buy power from alternative supply sources, to test the hypothesis that market forces produce rates lower than those under regulation.

During the pilot, the new supplier (either a generator or a power marketer) provides electricity, and the incumbent utility provides transmission and distribution facilities to its eligible customers who exercise the option of choosing a new supplier. Participating customers reimburse the new provider and the incumbent utility for the differentiated services.

Traditional billing mechanisms include the costs of generation, transmission, and distribution in a per-kilowatthour rate. A competitive regime commencing with the experimental pilot requires unbundling or a separation of the cost of generation from other cost components, so that the customers can pay the generation rate offered by the new supplier (or provider) and the transmission and distribution rates of the local, incumbent utility. In the process of unbundling, a competitive transition charge component to compensate the local utility for stranded costs that result from losing customers may also be separately included.

During the pilot, the local utility continues to have the obligation to serve customers within its assigned or franchised territory. Regulatory authorities protect customers by monitoring the activities of the incumbent utility and the new suppliers. At the end of the pilot, an evaluation indicates the issues that need to be addressed in the future.

[185] Michigan Public Service Commission, History: *Michigan Electric Utility Restructuring: A Chronology of Events.* (Revised Version as of February 12, 1998). Extracted from the Internet at http://ermisweb.cis.state.mi.us/mpsc/electric/restruct/history.htm, on March 6, 1998.

[186] A moratorium on rate increases or a rate freeze is another popular option that regulatory authorities invoke in lieu of PBR plans. States with a rate moratorium or a rate freeze include Oklahoma, Montana, and Nevada. Rate decreases—as in the case of Illinois—are called for in many States as a part of the restructuring process.

[187] Revenues from transmission assets (based on the sunk costs in transmission infrastructure) in the future will accrue to the utility through the intermediation of independent system operators. The applicability of PBR plans for transmission thus becomes a moot issue.

Purpose

Pilot programs are implemented with the objective of gaining experience as the electric power industry transitions toward competition. The New Hampshire Public Utilities Commission (NHPUC) defined the purpose of its pilot as "to create a limited experimental program to examine the implications of retail competition in the electric utility industry."[188] In addition to feedback on operational and logistic issues, the regulatory authorities wish to be assured that narrowing the gap between existing regulated prices and unregulated prices is a feasibility.

Types and Categories of Pilot Programs

Pilot programs may be started by utilities on their own initiative, by order of regulatory authorities, or by legislative enactments.[189] Pilot programs in Washington State were sponsored by the utilities.[190] Among the early pilots implemented, only the New Hampshire pilot (designed by the NHPUC) was the result of a legislative mandate.[191] Regulatory authorities in New York contributed to the establishment of pilot programs as a part of the restructuring process in the State.

Pilot programs fall into two broad categories: those designed for large customers (usually industrial or commercial firms) and those designed for residential and small business customers. The first category of program (for large customers) will usually have a small number of customers.[192] For such customers, the price of power often represents a significant element of the cost of their operations, and they have an incentive to save in order to maintain a competitive edge. For small customers, the penetration of retail choice depends on effective education and outreach efforts by the utilities and the regulatory authorities.[193] Most recent programs submitted by utilities include all customer classes, but pilots designed to meet sectoral needs are not rare.[194]

Participation in Pilot Programs

Participation in pilot programs varies among customer classes. The larger customers are more sophisticated in energy matters and have a vested interest in reducing their costs. They could be represented by trade organizations in the pilot design process or they could secure concessions by virtue of their size. In contrast, smaller customers may view the pilot program with apathy, because the savings, if any, may not be large enough to justify transaction costs.

Pilot Goals

Pilots initiated by utilities aim to gain experience of what the competitive market would be like in the future, to learn the technical and administrative details of retail access, and to get ready for the transition. The unbundling requirement forces the utility to get ready for competition, to seek appropriate remedies for costs that have the potential of being stranded, and to formulate a framework that ensures system reliability and quality of service.[195]

Pilots initiated by legislative enactments or regulatory orders have wider considerations. Regulatory authorities and lawmakers can evaluate the implications of and obstacles to retail competition, the impact on rates, patterns of customer responses, and the possible

[188] New Hampshire Public Utilities Commission, DR 95-250, Order No. 22,033, *Order Establishing Final Guidelines and Requiring Compliance Filings* (February 28, 1996).

[189] States with pilot programs (voluntary or mandatory) include Idaho, Illinois, Massachusetts, Missouri, New Hampshire, New Jersey, New York, Pennsylvania, Oregon, and Washington. Note that where utilities take the initiative, regulatory approval is still necessary.

[190] Electricity rates in Washington State are among the lowest in the Nation. In sponsoring pilot programs, the investor-owned utilities in the State may be testing their strengths in a competitive environment.

[191] The first six pilot programs were introduced in Illinois, Massachusetts, New Hampshire, New York, and Idaho. With the exception of the program in New Hampshire, the programs are utility specific. Participating utilities are Central Illinois Light Company, Illinois Power Company, Massachusetts Electric Company, Orange and Rockland Utilities , Inc., and Washington Water Power Company. The program in New Hampshire was mandated by the State legislature and designed by the New Hampshire Public Utilities Commission. For additional information and utilities participating in the pilot programs, refer to Edison Electric Institute, *Retail Pilot Programs: The First Six* (Washington, DC, 1997).

[192] For example, Central Illinois Light Company had only eight eligible customers in its pilot.

[193] Deborah Schachter (for the National Consumer Law Center and the Regulatory Assistance Project), *Public Outreach and Education in Electric Utility Restructuring* (Boston, MA, August 1996).

[194] An example is the "Farm and Food Processors Electric Retail Access Program," which is a 2-year pilot program in upstate New York that permits eligible farmers and food processors to choose electric service providers. The program was proposed by the Dairylea Cooperative and supported by the State's Department of Public Utilities. Four upstate investor-owned utilities participate in this sector-specific program.

[195] Besides the unbundling of rates and metering and billing protocols, customer information (or educational issues), customer protection, scheduling and power pool settlement process, and system reliability issues have also been dealt with.

magnitude of inroads that outside suppliers can make within a franchised territory. It is also possible to evaluate the extent to which free markets would tend to support activities that are not directly related with generation but would still need to be sustained.[196] Estimates of financial impacts on utilities are also feasible.

Besides gaining experience in promoting pilot programs, State regulatory authorities specify goals expected to be achieved in the process. For example, the Pennsylvania Public Utility Commission (PPUC), in directing jurisdictional utilities in the State to file electric retail access pilot proposals, established specific goals to be attained. An added requirement obligates utilities in Pennsylvania to explain how specified goals will be achieved by implementing the pilot proposals they file.

Goals set by the PPUC are:[197]

- To encourage development of a robust competitive retail market for electric generation and capacity
- To promote customer awareness of benefits and risks of competition and prepare customers to fully participate in retail competition through effective education and experience
- To encourage customer participation through choice of competitive options
- To foster safe and reliable service
- To preserve customer access to existing customer protection
- To test the effectiveness of integrated transmission system technical, physical, and commercial operations involving increased numbers of generation sources and transmission customers
- To ensure accurate, concise, and timely information exchange between local distribution suppliers and control area operators
- To establish fair business practice requirements to promote a broad array of qualified market sellers and willing buyers
- To assess and communicate pilot process results to the public.

Pilot Parameters

Stipulation of goals, as enumerated above, is invariably undertaken in conjunction with the specification of well-defined parameters that govern submission and approval of utility filings. In Pennsylvania, requirements for compliance include:[198]

- Pilot size to represent approximately 5 percent of a utility's peak load of each customer class.
- Pilot length to be at least 1 year.
- Pilot participation to be open to all customer classes.
- Pilots should describe the process by which electricity suppliers may participate and the operational standards required of them.
- A utility may offer competitive generation services to its traditional customers on the same basis as other suppliers. Options for eliminating anti-competitive behavior in such cases are examined. A code of conduct for utilities to observe is also provided.
- Utility tariffs to unbundle generation from jurisdictional transmission and distribution (T&D). The utility's terms and rates for transmission and distribution services to all other retail customers should be comparable to the utility's own use of its system.
- Rates for transmission access should be consistent with rates contained in the Federal Energy Regulatory Commission (FERC) tariff.
- Recovery of stranded costs may be included in the pilot programs.
- Electric generation supply agreements to meet reasonable operational standards.

[196] A number of activities fall into this category: social and environmental protection programs, low-income assistance programs, demand-side management, conservation and efficiency efforts, and use of renewables.

[197] Pennsylvania enacted the *Electric Generation Customer Choice and Competition Act* (Act 138 of 1996) on December 3, 1996. Also, see Pennsylvania Public Utilities Commission, Docket No. M-00960890, *Retail Access Pilot Programs–Guidelines* (January 16, 1997).

[198] Note that the dividing line between goals and parametric constraints imposed on utilities is not as clear cut as indicated above. The New York Public Service Commission views "allying concerns about market power" as a goal to be achieved.

- Consumer education and protection issues (including service safety and reliability) to be addressed in the pilot.

Regulatory Concerns

Even though the regulatory authorities set goals and define parameters for utilities to observe, there are still some legal issues that are of concern to them. Some of the issues that the NHPUC considered are listed below.[199]

- **Authority to order retail wheeling.** This authority is either implicit in the regulations governing public utilities in States or legislatively provided to the regulatory authorities where necessary. NHPUC contended that the FERC had no legal authority to prevent States from ordering retail wheeling.

- **Stranded cost recovery.** Most States offer utilities the opportunity to recover prudently incurred and nonmitigable stranded costs. Imposing constraints on this approach—as was done in New Hampshire—has delayed the transition to competition in the State.

- **Jurisdiction over interstate transmissions.** States have the jurisdiction to regulate the rates, terms, and conditions of distribution services in the State. However, the jurisdictional boundaries on transmission are far from clear according to NHPUC.

- **"Filed Rate" doctrine.** The issue here is whether the State regulatory authorities can "deny utilities with FERC-approved purchase power contracts the right to full recovery of power costs shifted to nonparticipating customers" through the application of adjustments to fuel and power costs. The NHPUC upheld the view that utilities will not be able to shift costs from pilot participants to nonparticipants.

There are also other operational issues that State commissions have to deal with in establishing pilot programs. Guidelines for unbundling are needed to ensure that suppliers get transmission service comparable to that which the utilities secure for themselves, letting customers know that they bear the responsibility for consequences of their choice, and finalizing rules for customer selection and supplier eligibility, billing, metering, and the sharing of customer-related data.

Size and Duration of Pilot Programs

Most pilot programs are small, ranging from a low of 2 megawatts in Washington to a high of 422 megawatts in Pennsylvania. For participating utilities, this represents a small fraction of their peak load. The duration of pilot programs varies from 1 to 5 years, with a majority having a 2-year term. Recent programs approved in Pennsylvania and Massachusetts have been for a 1-year period awaiting the introduction of direct retail access for all customers. The only program for a 5-year term was approved in Illinois for the Central Illinois Light Company in 1996. The potential loss of revenues, assuming maximum participation, is accordingly small in comparison with the potential for strandable costs in the event that direct access becomes universal.

Selection of Customers

Selection of customers depends on whether the pilot program includes all customer classes or targets only a specified class of customers. Where small customers (mostly residential and commercial business customers) are involved, it is common to define the geographic area of choice for their participation. Load limitation and the possibility of load aggregation may be factors in this decision. These considerations do not apply where large industrial or commercial customers are involved. The New York Public Service Commission, for example, approved a retail access pilot program in 1997 for qualified farmers and food processors in upstate New York, covering service territories of its four jurisdictional utilities.[200] Under this program, more than 17,000 farms and 600 food processors will be able to use the pilot to make choices about their power requirements based on the eligibility criteria instituted for the purpose.

Small residential and commercial business customers joining the pilot may or may not be allowed to leave the program at will. Some programs, as in New Hampshire, allow customers to switch to an alternative supplier as often as desired, but customers may not leave the pilot and then re-enter. Large customers usually sign up for a longer term, as in the case of the pilot set up by the

[199] New Hampshire Public Utilities Commission, DR 95-250, Order No. 22,033, *Order Establishing Final Guidelines and Requiring Compliance Filings* (February 28, 1996).

[200] New York Department of Public Service, Case 96-E-0948, *Petition of Dairylea Cooperative Inc. to Establish an Open-Access Pilot Program for Farm and Food Processors Electricity Customers* (June 10, 1997). The utilities involved are Niagara Mohawk Power Corporation, Central Hudson Gas and Electric Corporation, Rochester Gas and Electric Corporation, and New York State Electric and Gas Corporation.

Idaho Power Company, in which customers sign for loads ranging from 5 to 10 megawatts for a 3-year period.[201]

Eligibility of Suppliers and Providers

In recent years, electricity suppliers and marketers have proliferated. Encouragement is offered to a wide range of organizations that meet the eligibility requirements to participate in pilot programs.[202] Regulators invariably stipulate a set of requirements and criteria that suppliers have to meet to be eligible. The requirements vary by State.[203] Suppliers may be required to register with the regulatory authorities and provide evidence of their financial and technical capability to provide electricity to customers.[204]

Suppliers may be exempt wholesale generators, qualifying facilities, marketers and brokers, or jurisdictional utility marketing affiliates and nonaffiliates within or outside a State. Participation by local utilities through affiliates may be subject to approval by regulatory authorities. It is also not unusual to use a bidding process in choosing suppliers to meet the requirements of a selected group of customers.[205]

Other Issues

A host of issues need to be taken into account in establishing pilot programs. Metering, billing, marketing, customer education, and treatment of transition costs are among the issues on which directives are provided by regulatory authorities.

Evaluating Pilot Programs

Most pilot programs have only recently been implemented and are still ongoing (see Table 18, pages 86-92). These two factors make it difficult to evaluate their impacts. Two recent studies make the following observations:[206]

- Pilots are valuable in providing the participants (including the incumbent utilities) the experience they need prior to the commencement of full-scale competition.

- Development of technical procedures to implement the pilot is critical to its success. Pilot program design has been evolutionary, involving significant cross-fertilization.

- Customer acceptance response has been mixed. Large customer loads were fully subscribed. In fact, some of the large customers or their trade organizations often participated in the design development process, as in Illinois and Massachusetts. Residential and small business customers exhibited a lack of enthusiasm despite inducements in the form of guaranteed lower rates.[207]

- Low participation rates among residential and small commercial business customers could be attributed to insufficient savings, inadequate program promotion efforts, and complex or burdensome participation procedures. Where the size of the program is small, there may be no incentive for potential suppliers to participate.[208]

[201] The Idaho Public Utilities Commission, Case No. IPC-E-96-25, Order No. 26872, *In the Matter of Idaho Power's Application for Approval of Tariff (Schedule 20) Providing For Optional Market Based Service to Customers from 5 to 10 MW* (April 7, 1997). Note that this program designed for industrial customers does not envisage new providers but primarily accords the customers the choice of market-based rates during the currency of the contract, estimated to be 3 years.

[202] The pilot program set up for industrial customers in Idaho by Idaho Power is an exception. In this pilot program, outside providers do not participate.

[203] Eligibility requirements in New Hampshire are said to be more stringent than those in other States. In addition to meeting other criteria, New Hampshire requires that suppliers be members of the New England Power Pool (NEPOOL) or have a contract with a NEPOOL member.

[204] Regulatory authorities invariably specify a list of conditions that need to be met before a supplier is licensed in the State to supply power.

[205] The Massachusetts High Technology Council (MHTC), consisting of nearly 200 large business customers in the service area of Massachusetts Electric Company (MECO), entered into an agreement to establish a pilot program with MECO. MHTC chose to issue requests for proposals for supply of power. Out of 12 companies that submitted bids, MHTC made its selection based on considerations of economical supply of power, reliability and flexibility in accommodating loads, and cost control efforts. Refer to Edison Electric Institute, *Retail Pilot Programs: The First Six* (Washington, DC, 1997).

[206] Edison Electric Institute, *Retail Pilot Programs: The First Six* (Washington, DC, 1997); and Electric Consumers' Alliance, *The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation* (Indianapolis, IN, July 1997).

[207] Participation rates for residential customers range from a low of 3 percent in the case of Orange and Rockland Utilities in New York State to a high of nearly 60 percent in New Hampshire. National Renewable Energy Laboratory, *Selected Topics In Electricity Restructuring* (February 28, 1998).

[208] State of New York, Department of Public Service, *Status of Orange and Rockland Utilities PowerPick Retail Access Pilot as Reported to the Commission at the April 9 Session in Albany, NY* (May 15, 1997).

- Participating customers have generally been satisfied with the pilot programs. Price reductions needed to induce the customers were offered by the incumbent utilities. Some marketers sold power below cost.

- Factors influencing customer selection of suppliers generally include price and environmental considerations. Preference for local suppliers is also a contributory factor.

- Actual cost-saving benefits accrue across customer classes and programs. Overall, the percentage of savings secured by larger customers was higher than those secured by smaller and residential customers.[209] These differences could be attributed to the better bargaining strength of the industrial customers.

- Suppliers participating in the pilot programs are interested in gaining market share and experience rather than in making profits in the initial stages. This may explain why some of the suppliers charged prices that were lower than those anticipated (as in New Hampshire).

- Marketing electricity from renewable sources has not been a significant component of the pilot programs so far established. Programs in New Hampshire and Massachusetts that attempted to foster renewables indicate that customers may be willing to pay more for electricity from sources that are less polluting than conventional fossil-fired generating power plants. It is, however, unlikely that pilot programs in these States brought forth any new generation resources, and the assumption that existing resources were merely repackaged may be appropriate. To make the choices more transparent for customers, plans in the future may call for a complete disclosure of a supplier's generation profile, a breakdown of fuel sources, and a means to verify this information.

- Reliability did not emerge as an issue in the pilots, presumably due to the relatively small loads involved and the adequate reserve capacity.

- Customer service provided by the incumbent utilities should improve overall as pilots increase in any territory and competitive pressures increase. Included in this category are the billing and metering services that need revamping.

Unresolved Issues

As stated earlier, pilot programs are a mechanism for testing and experimentation so that regulators, utilities, and suppliers can all learn profitably. There are, however, issues that have not yet been fully resolved. Treatment of utility affiliates (and their ability to compete in the associated utility's territory) is one such issue.[210]

The tax impacts of pilot programs have not yet become an issue because of their relatively small size. However, as retail access choices become universal, revenue losses by incumbent utilities will become significantly more likely. If out-of-State suppliers play a dominant role, State revenues will be affected. Such losses could be offset by changes in the tax code, but this has yet to be done. Rules regarding regulatory certification of suppliers in a given territory may also need tightening to prevent potential abuses.

Conclusion

It is possible that additional issues will emerge as universal retail access gains momentum in the States and the overall demand for power continues to grow, eliminating the capacity excess that currently prevails systemwide. The success of fully competitive markets depends on the ability of the system to add capacity without undue constraints. Opening generation to competitive forces while concurrently retaining the current siting and licensing powers of regulatory authorities for new power plants and transmission lines may possibly limit the accrual of benefits that competition can bestow. Should shortages, therefore, develop either as a result of capacity or transmission constraints, it is difficult to rule out the possibility that some current generation or transmission owners will be able to augment economic rent collection.

[209] In New Hampshire, for example, the average bill savings for residential customers ranged from 12 to 16 percent, in comparison with a range of 15 to 20 percent for large commercial and industrial customers. The New York pilot program shows similar results.

[210] The concern is that the relationship between the utility and the affiliate (if the latter is allowed to compete in the same market as the parent/incumbent utility) is such that market abuses can flourish. An example would be for the affiliate to exercise the market power enjoyed by the incumbent utility and to retain market share by predatory prices. Any losses that might result could be passed on to the parent company.

Table 18. Retail Pilot Programs as of April 30, 1998

Idaho:

Establishment of pilot programs is not mandated in Idaho. The currently established plans were sponsored by the utilities operating in the State.

Two proposals submitted by the Washington Water Power Company (WWPC) were approved. The *Direct Access Delivery Service* (DADS) pilot covers extra large general service customers who can exercise their option of securing up to a third of their load from alternate suppliers. The total maximum load of this program is 33 megawatts. Participants are required to pay about 1.4 cents per kilowatthour for delivery service and would stand to gain if power from alternative sources can be obtained below a price of 1.6 cents per kilowatthour. This 2-year program began July 1, 1996, and runs through August 31, 1998. The second program, known as *More Options For Power Service* (MOPS), includes all customer classes and is expected to run from July 1, 1997, through June 30, 1999. The pilot was planned to include about 1,900 customers in Washington and Idaho. The distribution rates that WWPC charges vary depending on the rate schedule. However, due to lack of interest on the part of suppliers, all parts of the pilot (including Idaho's eligible customers) outside of two towns in Washington were deferred.

In January 1998, a MOPS II proposal was approved. This pilot allows WWPC customers to choose between several energy service alternatives without changing providers. The pilot will be available to 5,570 residential, commercial, and agricultural customers in Hayden and Hayden Lake, Idaho. Customers in Deer Park, Washington, are also eligible. Idaho's portion of the pilot accounts for 11 megawatts of load. This 2-year pilot begins May 1, 1998. It offers customers different pricing options to choose from besides the traditional pricing mode from the incumbent provider. This includes "green" resource pricing where the customers choose to pay an incremental amount to support the development and operation of renewable resources. The energy service prices for transmission and distribution in the traditional energy service option range from 2.2 to 2.3 cents per kilowatthour, depending on customer class. Customers choosing options with lower costs will save on their electric bills.

Idaho Power Company's (IPC) pilot provides optional market-based service to large industrial customers who contract for 5 to 10 megawatts of firm demand at one point of delivery. A distinguishing characterization of this pilot is that customers remain with IPC and are not permitted to opt for another supplier. Electricity prices for participants are, however, determined by the Dow Jones-California-Oregon Border (DJCOB) index or by futures contracts traded on the New York Mercantile Exchange (NYMEX) for the California-Oregon border delivery point. Customers select what increment (by percentage) of energy will be priced according to the market. Approximately 10 customers are eligible to participate, and with each contracting for between 5 and 10 megawatts, the total load of this pilot could potentially reach 100 megawatts. Customers had until December 31, 1997, to sign agreements. Each agreement lasts for 3 years.

Illinois:

In August 1995, the Central Illinois Light Company (CILCO) voluntarily filed two retail access pilot programs, known as *Power Quest,* with the Illinois Commerce Commission (ICC). Along with Illinois Power Company (IPC), CILCO became one of the first utilities in the country to make such an offer.

CILCO's pilot programs started on May 1, 1996. Its first pilot program—*Rate 33*—was designed exclusively for industrial customers. The aggregate load that can be acquired from outside suppliers is fixed at 50 megawatts of capacity (on the utility's transmission and distribution system). CILCO's eight largest industrial customers having a demand of 10 megawatts or more are eligible to participate. This pilot has a duration of 2 years and is planned to expire in May 1998.

CILCO's second pilot program—*Rate 34*—is designed for commercial and residential customers located within "open access sites" or specially designated areas of the utility's service territory. This pilot runs for a 5-year period through 2001. Customers, limited to about 5,500, can acquire a maximum load of 50 megawatts from off-system suppliers.

For both pilots, CILCO proposed unbundling the rates for its transmission and distribution services. Revenue losses resulting from these pilots are absorbed by the utility's shareholders. During the first year of the pilot programs, Rate 33 was fully subscribed even though the subscribed load was not being fully utilized. Rate 34 had a participation rate of about 25 percent. Total net revenue losses by CILCO averaged about 1.95 cents per kilowatthour during the first 6 months of 1997. CILCO claims that its shareholders will absorb the lost revenues, stating that it views this loss as an investment to bring consumer choice to the State.

Table 18. Retail Pilot Programs as of April 30, 1998 (Continued)

Illinois (Continued)

IPC's pilot, *Direct Energy Access Service* (DEAS), includes 21 large customers eligible for a total of 50 megawatts of IPC's system load. Eligible customers maintained a minimum load of 15 megawatts during the 24-month period ending in September 1995. The program began on April 25, 1996, and will continue through December 31, 1999.

Participants in the pilot will pay IPC for its unbundled transmission and distribution services. The utility reports that 16 of the 21 eligible customers have been participating in the pilot. IPC estimated a net annual revenue loss of $3.1 million to $7.5 million. Actual revenue losses have not been made public, but were filed with the ICC in March and in September 1997. These losses are being recovered jointly from shareholders and participating customers.

Massachusetts:

In August 1995, Massachusetts Department of Public Utilities (currently known as the Department of Transportation and Energy or the MDTE) released its order outlining principles and guidelines for electric utility restructuring in the State. The MDTE embraced the notion of competition in generation to achieve its primary goal of reducing costs, over time, for all electricity customers in the State.

With a view to meet the above goal, utilities in the State were ordered to file restructuring plans by February 1996. In response to this requirement, the Massachusetts Electric Company (MECO)—a subsidiary of New England Electric System—filed its proposal to establish a pilot program in its service territory.

Choice: New England—as MECO's plan was called—includes two pilots, one for large technology companies with the collaboration and participation of the Massachusetts High Technology Council (MHTC) and the other for residential and small business customers. Both plans give the customers the option of choosing their electricity suppliers.

The MHTC pilot started on July 9, 1996. Proposals for a total of 200 million kilowatthours per year were solicited from suppliers. Twelve suppliers submitted bids in this pilot. The MHTC made its selection taking into account factors that included economic and non-economic considerations. Fifteen members of the MHTC joined the pilot.

The residential and small business pilot started on January 2, 1997. The program was designed to provide for retail choice for up to 10,000 residential, small business, and industrial customers or up to 100 million kilowatthours per year. This pilot drew 15 suppliers who submitted 42 proposals. The proposals included the options of price, "green energy," or energy combined with other valuable services. Each supplier was required to be a member of the New England Power Pool (NEPOOL) or have a contract with a NEPOOL member for inclusion of its load in the member's load.

The residential and small business pilot is expected to run for a year or until retail choice becomes available in Massachusetts. During the pilot, customers can return to get service from MECO. However, they cannot rejoin the pilot if they choose to leave. This provision applies to the MHTC pilot as well.

MECO was required to implement a functional separation of generation from transmission and distribution services. Based on this functionalization of costs, the utility bills the customers in both pilots for transmission, distribution, and access charges (which include the cost of its stranded investments). In addition, rules for affiliate involvement in the pilot were also finalized.

Two other utilities in the State—Boston Edison Company (BECO) and the Commonwealth Electric Company (Com/Electric)—also filed pilot programs. BECO's pilot, part of its *E-Plan,* was filed in January 1996 to include 10 large customers (that use at least 1 megawatt of electricity at any given time) subject to a maximum load limit of 30 megawatts for all customers.

Customers were required to pay a customer charge (a variable charge depending on use characteristics), a demand charge (a fixed amount per megawatt discounted by 10 percent), and an access charge. Availability of pricing information, for each hour, on a real-time basis enabled customers to adjust their consumption patterns and secure further savings. Absent such changes, unbundled charges retain revenue neutrality. BECO's retail pilot expired on January 31, 1997. No evaluation of the program is available.

COM/Electric filed a retail choice pilot program in August 1996 and was approved to begin in October 1996. The plan offered two choices to participants: Subscription A and Subscription B. Subscription A allowed a total of 10 customers to obtain

Table 18. Retail Pilot Programs as of April 30, 1998 (Continued)

Massachusetts (Continued)

generation from alternate suppliers subject to a maximum of 15 megawatts of aggregate load. Subscription B allowed customers to take electric service from the utility based on a market-price proxy (determined a day ahead) and open to customers not electing to participate in the Subscription A option. Twenty accounts, made up of 18 customers, comprised the group of eligible customers with an aggregate load of 50 megawatts. Subscription A, however, was canceled due to a lack of suppliers. Subscription B continued through the originally planned January 31, 1997 end date.

Missouri:

A task force created by the Missouri Public Service Commission (MPSC) released its final report dealing with retail competition in May 1998. There are no requirements in the State to establish pilot programs at this time.

UtiliCorp United Inc., an investor-owned utility in the State voluntarily filed a proposal in 1996 to initiate an *Electric Transitional Aggregation Experiment* to allow a subclass of commercial customers the opportunity to gain experience in securing power at competitive rates. The objective of the experiment is to gather information about the aggregation of customer loads and the infrastructure required to serve the loads together with the electric power delivery service.

Demand to be served under UtiliCorp's program is limited to a total of 25 megawatts subject to the ability of each customer to receive service at a minimum of 20 points of delivery with a demand in excess of 2.5 megawatts. Qualified customers will be given the opportunity to buy their electricity from other suppliers while continuing to use the transmission and distribution system already in place. They will also receive a credit of about 0.02 cents per kilowatthour representing energy cost, implying that the utility may not currently be required to unbundle its rates.

The pilot, which began in February 1997, runs until the end of 1998. The utility will provide an evaluation of the program at the end of 1997 and 1998.

The utility currently serves a total load of about 10 megawatts under this pilot. Note that the State laws preclude power sales from outside suppliers directly to end-users. The utility, therefore, acts as a conduit to facilitate such sales in an attempt to promote competition until appropriate legislation is enacted in the State.

The MPSC, however, did ask the Union Electric Company (UEC) to establish a pilot program as a part of its approving UEC's merger application with Central Illinois Public Service Company (CIPSCO). UEC submitted its proposal in September 1997 to test two market structures: one that gives customers a direct access to a group of qualified power suppliers and the other which enables customers to enroll in a power exchange program authorizing the utility to shop for the best electric prices. Approval from the MPSC is still awaited.

New Hampshire:

Legislation enacted in New Hampshire in June 1995 (NH RSA 374:26-a) mandated that the New Hampshire Public Utilities Commission (NHPUC) undertake the establishment of a pilot program for the purpose of determining the implications of retail competition in the electric industry. In response to this mandate, the NHPUC initiated and finalized guidelines for the proposed pilot in early 1996.

Guidelines issued by the NHPUC laid out the basic pilot design and monitoring and evaluation procedures to be followed. The pilot program would enable the NHPUC to determine interest among customers and suppliers and scrutinize whether all customer classes benefit from its implementation. In addition, the financial impact of the pilot on utilities could also be evaluated. Directing the utilities to develop unbundled rates would be another plus.

Prior to the commencement of the proposed pilot for a 2-year term in May 1996, the NHPUC incorporated additional provisions in its design. The program planned to include customers of any one of the six franchised utilities in the State. Issues raised by a rural cooperative—the New Hampshire Electric Cooperative—precluded its participation. Customers of public power utilities were also excluded. The program has since been extended beyond May 1998.

Table 18. Retail Pilot Programs as of April 30, 1998 (Continued)

New Hampshire (Continued)

Participants were to be randomly selected from the pool of volunteers to be limited to a total of about 17,000. Subject to this limit, residential and small customers could also participate in the pilot either individually or as a part of a "geographic area of choice." Suppliers could have access to 3 percent of each designated utility's existing retail load approximating about 51 megawatts. This total does not include new business and commercial load that may be served under the pilot program.

Utilities in the pilot program were required to disaggregate their bundled retail services into various cost components: customer service, transmission, distribution, conservation and load management, and power supply. The power supply function would be further split between market price and stranded cost components. In billing the customers, the utilities would show these items separately but would reduce the energy cost by the estimated market price for power. The offset for energy costs for residential customers was estimated to be 3.7 cents per kilowatthour, implying that the customer benefitted if power could be secured at a rate lower than the offset. In addition, participating customers were also given a credit equal to 10 percent of the customer's total bill, reflecting an incentive credit for participation.

During the duration of the pilot, suppliers and utilities had to abide by conduct rules specified by the NHPUC. To ensure reliability, every supplier was required to be a member of the New England Power Pool (NEPOOL) or have a contract with a NEPOOL member. Registration with NHPUC was also required. Utilities could not compete directly but could do so through their affiliates in the pilot.

In February 1997, the NHPUC released results of a survey of its pilot program conducted by the New Hampshire Institute for Policy and Social Science Research. According to NHPUC, the survey substantiates the value of pilot programs as a valuable tool and confirms the technical feasibility of retail competition. Critics contend that the New Hampshire experiment (with its own unique set of conditions) postponed consideration of certain critical issues to a later date and that its success in the pilot may not smooth implementation of retail competition to all customers. Its experience may also be difficult to transfer to other States.

New Jersey:

The New Jersey Central Power and Light Company, doing business as GPU Energy (GPU), voluntarily filed a petition with the New Jersey Board of Public Utilities (BPU) to establish a pilot program in Monroe Township, New Jersey. GPU's first plan (submitted in December 1996) proposed retail competition for all 11,900 residents of Monroe Township on an energy only basis. This plan, however, could not be implemented due to a lack of an acceptable supplier's bid.

Based on securing an acceptable supplier, the GPU filed a revised petition on August 15, 1997, for establishing the pilot program. The pilot incorporates a three-tiered pricing for residential, commercial, and industrial customers. The utility is not required to unbundle its rates. Instead, it will continue to bill each participating customer at prevailing tariff rates. At the same time, the participating customer will receive an energy credit not exceeding 2.7 cents per kilowatthour. The customer would also pay the energy charge claimed by the supplier and would benefit if the price was lower than the energy credit of 2.7 cents per kilowatthour. In the event that a supplier's energy charge exceeds the 2.7 cents per kilowatthour energy credit, GPU will absorb the resulting loss.

The BPU has taken care to ensure that cross-subsidization among different customer classes will not occur as result of implementing the pilot. The pilot commenced on September 15, 1997, and runs for a period of 1 year, but it can be extended until October 1998, when the first phase of competition is slated to begin in New Jersey.

New York:

The New York Public Service Commission (NYPSC) issued a decision in May 1996 seeking to promote competition in the electric utility industry in the State. To meet this goal, utilities in the State were directed to file restructuring and rate plans. In complying with this requirement, utilities crafted details of pilot programs to be established by them.

The State's first pilot, a two-part retail access pilot project called *PowerPick*, was approved as a result of an electric rate settlement for the Orange and Rockland Utilities, Inc. (O&R) on May 3, 1996. Phase I of this program, involving the larger industrial and commercial customers, went into effect on July 1, 1996. The amount of energy that customers in the Phase I program could purchase from alternative suppliers was limited by the minimum off-peak load requirements of the utility. This phase was fully subscribed. Its implementation was successful and resulted in savings to the participating customers. Phase

Table 18. Retail Pilot Programs as of April 30, 1998 (Continued)

New York (Continued)

II of the program, for residential and smaller commercial and industrial customers, commenced on January 1, 1997. Participation in this phase was lower than expected, and potential savings to customers were small.

Customers in *PowerPick* had to commit to remain in either program for 1 year. They could leave but could not rejoin for the next year. Load offered in Phase I was limited to 30 megawatts of off-peak demand and about 10 megawatts in the Phase II program. Extending the duration of this pilot beyond the initial 1-year period hinges on the results of review by the NYPSC.

In June 1997, the NYPSC approved a new 2-year retail pilot program. About 17,100 farmers and 600 food processors in the service territories of Niagara Mohawk Power Corporation, New York State Electric and Gas Company, Rochester Gas and Electric Company, and Central Hudson Gas and Electric Corporation were given the option to shop for electricity and other energy services. Customers in the territory of Orange and Rockland utilities could choose to participate in the utility's existing *PowerPick* program.

Subject to meeting specified eligibility criteria, participants could seek alternative sources of supply. While specifics differ among utilities in the pilot, they generally proposed to subtract from their bundled rates the market price of energy and capacity. Only one utility—the Central Hudson Gas and Electric Corporation—indicated that it will recover 50 percent of its lost revenues associated with nonfuel production costs. In addition, utilities will back out an additional amount to include costs other than energy and capacity. Thus, delivery rates offered range from 2.2 to 3.8 cents per kilowatthour (exclusive of the backout amount). Recovery of strandable costs is embedded in these rates.

Information on loads is not readily available and depends on the aggregate number of participants. (By the end of December 1997, nearly 5,000 participants had joined the pilot.) Utilities in the program have an obligation to provide initial reports 3 months after the start of the pilot to the NYPSC. Since all utilities (except Rochester Gas and Electric Company) had to start their pilots no later than November 1, 1997, data on loads and other issues will become available sometime in 1998 for evaluation.

The Consolidated Edison Company of New York also established a pilot program, called *Retail Choice*, due to start June 1, 1998. The program was originally filed to serve approximately 63,000 customers, for a total load of 500 megawatts. However, customer demand for the program was strong and the pilot expanded to a load of 1,000 megawatts. Additional loads of 1,000 megawatts will be offered in 1999 and 2000. Pilot programs of other utilities are also subject to changes due to the announced policy of NYPSC to implement full retail access by December 2001.

Oregon:

Portland General Electric Company (PGE) voluntarily filed a direct access pilot program in August 1997. The *Customer Choice Pilot Program*, approved October 21, 1997, runs from December 1, 1997, through December 31, 1998. The pilot allows 50,000 retail customers in four Oregon towns to choose their electric suppliers. In addition, all industrial customers throughout Oregon having a load greater than 5 megawatts will also be eligible to participate. Under this pilot program, approximately 15 percent of the utility's system load will become eligible for retail choice.

The pilot introduces seven Energy Service Providers (ESP) in the program. Customers have the option to aggregate their demands and secure a better deal with an ESP. PGE will continue to bill for distribution services (made up of a basic charge and a usage charge). These charges are derived by subtracting PGE's energy cost from the total bundled costs. The ESPs bill customers for energy.

Another Oregon investor-owned utility, Pacific Power and Light Company (PacifiCorp), filed an Experimental Customer Choice Program in January 1998. The pilot was approved April 1998 and includes residential and small commercial customers in Klamath County who will be able to choose from a "portfolio" of pricing options offered by the utility. Also included in the filing are schools and large industrial customers located in PacifiCorp's territory in Oregon. Pricing configurations under the "portfolio" approach include market-based pricing and renewable energy options. The utility plans to participate in the pilot as an energy service provider through an affiliate.

Table 18. Retail Pilot Programs as of April 30, 1998 (Continued)

Pennsylvania:

On December 3, 1996, the Pennsylvania legislature passed into law the *Electricity Generation Customer Choice and Competition Act of 1996.* The legislation opens electric utility generation in the State to competition. The Pennsylvania Public Utility Commission (PPUC) is authorized to order electric utilities to submit proposals for retail access pilot programs as a prelude to testing the full impacts of competition. The legislation also outlines a set of procedural requirements in establishing pilots.

In compliance with the legislative directive, the PPUC first established goals to be achieved and guidelines for the State's pilot program. Next, the PPUC directed all major jurisdictional utilities in the State to file pilot proposals consistent with these goals and guidelines by March 1, 1997.[a]

In response, eight investor-owned jurisdictional utilities filed company-specific pilot programs. The PPUC issued preliminary opinions and orders in May and June 1997 which became the subject of further comments and hearings. A joint settlement applicable to all utilities, announced on August 21, 1997, paved the way for establishment of eight retail pilot programs starting on November 1, 1997, and continuing until December 31, 1998.

Requirements for the eight pilots are similar for each utility. Each utility's pilot provides choice for approximately 5 percent of its non-coincident peak load for each customer class. Estimated loads, however, vary among utilities from a low of about 11 megawatts for UGI Utilities Inc., to a high of about 422 megawatts for PECO Energy Company, totaling over 1,300 megawatts of load. About 250,000 customers are expected to participate in these pilot programs. Since the pilot programs were oversubscribed during the open enrollment process, utilities selected participants by conducting a lottery.

Participating customers are entitled to a generation credit and a customer participation credit, depending on their customer class category and their location. The generation credit for residential and commercial customers is 3.0 cents per kilowatthour. Industrial customers will receive a 2.4 cents per kilowatthour credit. The customer participation credit, which is based on the utilities' delivery charge, is 13 percent for residential and commercial customers and is reduced to 10 percent for industrial customers. Some variations in these rates are permitted to accommodate special circumstances of specific utilities. For example, the customer participation credit for all customers classes of UGI Utilities Inc. is somewhat lower (5 percent for residential and commercial customers and 8 percent for industrial customers). Customers save money when they can purchase energy at a rate lower than the generation credit.

Although the utilities did not fully unbundle their rates except for the limited purpose of the pilot, customers still contribute to the recovery of stranded costs. The total rate chargeable to customers by utilities includes unbundled distribution and transmission rates, as submitted by utilities. In addition, a competitive transition charge (based upon a 75 percent recovery of utilities' generation costs in excess of the State-wide market rate for energy and capacity estimated at 3.0 cents per kilowatthour) is also included.

The PPUC requires utilities to abide by requirements in other operative areas. Customer education and protection programs are mandated, along with provisions for service, safety, and reliability. Billing and metering procedures are specified. A quarterly evaluation procedure aims to fine tune the program.

Washington:

Pilot programs were filed by two investor-owned utilities in Washington State—the Washington Water Power Company (WWPC) and the Puget Sound Power and Light Company (PSP&L).

WWPC voluntarily filed three pilot programs. The first pilot program, the *Direct Access Delivery System* (DADS), was approved to begin in August 1996 and to continue through August 1998. DADS is limited to large commercial and industrial customers. Eligible customers can transfer up to a third of their current load. In total, about 27 megawatts of the utility's load will be eligible. Customers will pay approximately 1.5 cents per kilowatthour for transmission and distribution costs. WWPC will absorb all transition costs during the pilot.

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[a]PECO Energy Company, Pennsylvania Power and Light Company, Duquesne Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, and Allegheny Power Company were directed to file their pilot proposals by March 1, 1997. UGI Corporation and Pennsylvania Power Company were directed to file by April 1, 1997. Other utilities were either exempted or were not required to submit pilot programs.

Table 18. Retail Pilot Programs as of April 30, 1998 (Continued)

Washington (Continued)

WWPC's second pilot, *More Options for Service Providers* (MOPS), is smaller in scale, with 981 customers in two towns eligible for a total load of 2 megawatts. The pilot began July 1, 1997, and will conclude June 30, 1999. The pilot's size was reduced from the originally proposed 8.2 megawatts of load and 2,800 customers due to a lack of interest by suppliers. Rates for transmission services vary based on type of service. Stranded costs are split evenly between WWPC shareholders and customers in the MOPS pilot.

The third customer choice pilot program—MOPS II—was approved in February 1998. The primary difference between MOPS II, and the MOPS and DADS pilots is the availability of energy service alternatives to customers without their having to change energy service providers. To facilitate the implementation of MOPS II, eligible customers (consisting of about 7,800 residential, small commercial, large commercial, and agricultural pumping service customers in Washington and Idaho States) would have access to a menu of energy service alternatives at market prices reflecting actual competition among suppliers. The utility asserts that the MOPS II model would extend economic benefits of competition to the customers. The pilot is for a 2-year duration from May 1, 1998, through April 30, 2000, with a total eligible load of about 16 megawatts between the two States.

As part of the approval of its market transition plan, the Puget Sound Power & Light Company (PSP&L) was required to file a retail pilot program. The pilot runs from November 1, 1997, through December 31, 1999. All customer classes may participate in selected geographic regions. The maximum number of participants is 10,321, with a total load of about 32 megawatts. The largest loads are subject to a 5-megawatt cap. Customers participating in the pilot will be offered rate discounts that vary according to customer class, with residential customers receiving the largest discounts. Separate distribution rates were also established. PSP&L will absorb or defer the costs of the pilot.

5. State and Federal Restructuring Initiatives

Background

Regulatory oversight of the electric utility industry, as it evolved since its inception, is essentially an artifact of State economic regulation.[211] While the evolutionary development of this industry into a "natural monopoly" insulated it from market forces of competition, a regulatory regime monitored various facets of the industry's pricing and earnings activities as a surrogate for competition. Federal legislation followed State regulation and is "premised on the need to fill the regulatory vacuum resulting from the constitutional inability of States to regulate interstate commerce."[212]

Since the passage of the Energy Policy Act (EPACT) in 1992 and the issuance of Order Nos. 888 and 889 by the Federal Energy Regulatory Commission (FERC) in 1996 to promote competition in wholesale electricity trade, States have been active in paving the way for promoting competition at the retail level–the next frontier.[213] All but one of the 50 States, either through their regulatory commissions, legislatures, or both, are considering or implementing policies to provide greater options for retail electric customers.[214] By early 1998, 18 States had acted to restructure the electric industries in their States and to facilitate development of competition in retail electricity trade in their States during the next 5 years (Figure 22).[215] Some States have already called upon their jurisdictional utilities to unbundle the generation, transmission, and distribution components of their tariffs; others are working with partial unbundling during the currency of their experimental pilot programs.[216] Only a small number of States have so far postponed immediate action on restructuring by moving at a slower pace. In addition, members of both the 104th and 105th Congresses have introduced legislation to facilitate competition at the wholesale and retail levels.

Both State and Federal legislators strongly believe in the conceptual outcome of opening electricity generation to the discipline of the market. A competitive industry, as claimed by its proponents, will lead to greater economic efficiency and lower prices for consumers.[217] In the process, shareholders may assume greater risks but will also enjoy the prospects of higher rewards. Skeptics contend that the benefits of competition may not be evenly spread and that smaller consumers may be at a disadvantage.[218]

The potential benefits of bringing more competition into the industry in the form of lower prices will depend on the nature of the implementation strategies adopted. Current proposals take two distinct approaches: wholesale competition and introducing competition at the retail level. The terms of wholesale sales between utilities or between utilities and independent power

[211] C.G. Stalon, "The Historical Context of U.S. Industry Restructuring: Selections Emphasizing Public Policy Decisions," *NRRI Quarterly Bulletin*, Vol. 17, Nos. 1 and 2 (1996).

[212] Congressional Research Service, *Electricity: A New Regulatory Order?* Report prepared for the Committee on Energy and Commerce, U.S. House of Representatives, 102nd Congress, 1st Session, Committee Print 102-F (June 1991).

[213] Only the generation market is involved in promoting competition at the wholesale and retail levels. As such, transmission and distribution services continue to be "natural monopolies" subject to regulation in the future.

[214] Testimony of Hon. Bruce B. Ellsworth, Commissioner, New Hampshire Public Utilities Commission, and President, National Association of Regulatory Utility Commissioners, before the U.S. Senate Committee on Energy and Renewable Resources on March 20, 1997 (Electric Utility Restructuring Hearing).

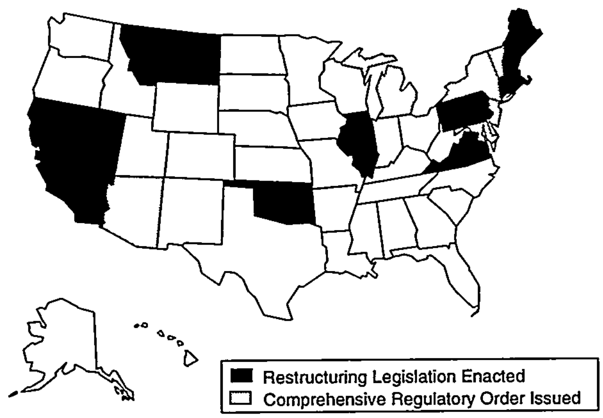
[215] The 18 States are Arizona, California, Connecticut, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New York, Oklahoma, Pennsylvania, Rhode Island, Vermont, and Virginia.

[216] States that have already ordered unbundling of tariffs include California, Connecticut, Mississippi, and Rhode Island. In States where pilot programs have been established as a prelude to opening the industry to competition, the unbundling of rates may initially be in two broad categories, consisting of generation costs and transmission and distribution costs. At a later date, the States will require utilities to fully unbundle their rates prior to the commencement of competition in retail electricity trade.

[217] Additional benefits resulting from competition in generation are also claimed. Refer to J. H. Moorhouse, "Competitive Markets for Electricity Generation," *The Cato Journal*, Vol. 14, No. 3 (Winter 1995).

[218] J. Taylor, *High-Voltage Swindle: Why Electricity Restructuring Could Electrocute Ratepayers* (The Cato Institute, February 6, 1997).

Figure 22. States Which Have Issued Comprehensive Deregulation Orders and/or Enacted Restructuring Legislation as of June 1, 1998



Notes: **States with Legislation:** California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia. **States with Orders:** Arizona, Maryland, Michigan, New Jersey, New York, and Vermont. Note that California, Massachusetts, and New Hampshire each have regulatory orders and legislation in place.

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

producers are regulated by the FERC.[219] Generation, transmission, and distribution services provided by any integrated utility to all its customers within its franchised territory are considered retail sales or retail transactions. Retail customers invariably pay single, combined, or bundled prices regulated by State regulatory authorities. Significant differences characterize the needs of wholesale and retail customers. The prevailing diversity of interests between the two groups—wholesale and retail—and among stakeholders within each group creates complexities that do not easily lend themselves to a solution.

Congressional Initiatives

Proposed congressional legislation aims to open electricity markets to retail competition so that all customers can exercise the option to choose their own electricity providers and impediments to competition can be removed. To meet these objectives, a number of bills were introduced in the 104th and 105th Congresses. A brief summary of bills introduced in the 105th Congress is provided in Table 19. More detailed information is available in Appendix F.

Legislation introduced in the 105th Congress covers diverse spheres of restructuring activity. Some bills are comprehensive—expanding on initiatives contained in EPACT and building on the actions of the FERC (in promoting competition at the wholesale level) to facilitate retail competition by a date certain. Others focus on a variety of selected restructuring issues.

Eliminating impediments to competition that may result from continuing the provisions of the Public Utility Regulatory Policies Policy Act of 1978 (PURPA) or the Public Utility Holding Company Act of 1935 (PUHCA) have been addressed specifically. Rectifying constraints imposed on public utilities resulting from the use of tax-exempt financing constitutes another critical issue on the legislative agenda. Finally, there are a number of transitional and/or non-economic regulatory issues that either are part of the comprehensive legislation or have been addressed separately. Providing jurisdictional demarcation of Federal and State authority, recovery of stranded costs, implementation of environmental protection, reliability, public assistance programs, demand-side management, and others have also been included. It is possible that additional subjects may be added in the future.

The House and the Senate also organized many workshops in 1997 with an intent to seek a collective consensus on relevant issues in the restructuring debate from interested stakeholders. Whether Federal legislation is necessary was one of the early issues before the Committee on Energy and Natural Resources of the U.S. Senate. In a hearing in 1997 before the Committee, issues that may warrant Federal legislation were assessed by the FERC. Its recommendations included:

- Congress should require all nonpublic utilities that own, control, or operate transmission to open up their systems so that a nationwide competitive market in wholesale trade becomes feasible and can operate in a seamless fashion.[220]

[219] FERC also oversees the pricing and selling arrangements applied by power pools (like the Pennsylvania-New Jersey-Maryland power pool), because these represent wholesale sales.

[220] FERC's open access program applies to all public utilities it regulates. FERC currently lacks jurisdiction over the third of the country's transmission system that is owned and operated by Federal power marketing administrations, municipalities, most cooperatives, and the Texas intrastate activities of the member utilities within the Electric Reliability Council of Texas (ERCOT.)

Table 19. Proposed Legislation Influencing the Restructuring of the Electric Power Industry During the 105th Congress as of May 31, 1998

Bill	Purpose/Sponsor
H.R. 338 "Ratepayer Protection Act"	Repeals Section 210 of the Public Utility Regulatory Policies Act. Introduced on January 7, 1997, by Representative Clifford Stearns (R-FL).
H.R. 655 "Electric Consumers' Power to Choose Act of 1997"	Gives all American electricity consumers the right to choose among competitive providers of electricity, in order to secure lower electricity rates, higher quality service, and a more robust U.S. economy, and for other purposes. Introduced on February 10, 1997, by Representative Daniel Schaefer (R-CO).
H.R. 1230 "Consumers Electric Power Act of 1997"	Grants electricity consumers the right to choose among competitive providers of electricity and amends PUHCA and PURPA. Introduced on April 8, 1997, by Representative Thomas DeLay (R-TX).
H.R. 1359 "A Bill to Amend the Public Utility Regulatory Policies Act of 1978 to Establish a Means to Support Programs for Electric Energy Conservation and Energy Efficiency, Renewable Energy, and Universal and Affordable Service for Electric Consumers."	Amends the Public Utility Regulatory Policies Act of 1978 and establishes a means to support programs for electric energy conservation and energy efficiency, renewable energy, and universal and affordable service for electric consumers. Introduced on April 17, 1997, by Representative Peter DeFazio (D-OR).
H.R. 1960 "Electric Power Competition and Consumer Choice Act of 1997"	Modernizes the Public Utility Holding Company Act of 1935, the Federal Power Act, the Fair Packaging and Labeling Act, and the Public Utility Regulatory Policies Act of 1978 to promote competition in the electric power industry, and for other purposes. Introduced on June 19, 1997, by Representative Edward Markey (D-MA).
H.R. 2909 "To Amend the Federal Power Act To Establish Requirements Regarding the Operation of Certain Electric Generating Facilities, and for Other Purposes."	Amends the Federal Power Act to establish requirements regarding the operation of certain electric generating facilities, and for other purposes. Introduced on November 7, 1997, by Representative Frank Pallone, Jr. (D-NJ).
H.R. 3548 "Environmental Priorities Act of 1998"	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 on March 25, 1998, by Representative Robert E. Andrews) D-NJ).
H.R. 3927 "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"	Amends 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 on May 21, 1998, by Representative Phil English (R-PA).

Table 19. Proposed Legislation Influencing the Restructuring of the Electric Power Industry During the 105th Congress as of May 31, 1998 (Continued)

Bill	Purpose/Sponsor
H.R. 3976 **"A Bill to Repeal the Public Utility Holding Company Act of 1935, to enact the Public Utility Holding Company Act of 1998, and For Other Purposes"**	Repeals the Public Utility Holding Company Act of 1935, and enacts the Public Utility Holding Company Act of 1998 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 on May 22, 1998, by Representative W.J. (Billy) Tauzin (R-LA).
S. 237 **"Electric Consumers Protection Act of 1997"**	Provides for retail competition among the electric energy suppliers for the benefit and protection of consumers, and for other purposes. Introduced by Senator Dale Bumpers (D-AR) on January 30, 1997.
S. 621 **"Public Utility Holding Company Act of 1997"**	Repeals the Public Utility Holding Company Act of 1935, and enacts the Public Utility Holding Company Act of 1997, and for other purposes. Introduced by Senator Alfonse D'Amato (R-NY) on April 22, 1997.
S. 687 **"Electric System Public Benefits Protection Act of 1997"**	Enhances the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency, and for other purposes. Introduced by Senator James Jeffords (R-VT) on May 1, 1997.
S. 722 **"Electric Utility Restructuring Empowerment and Competitiveness Act of 1997"**	Benefits consumers by promoting competition in the electric power industry, and for other purposes. Introduced by Senator Craig Thomas (R-WY) on May 8, 1997.
H.R. 1276 **"The Federal Power Act Amendments of 1997"**	Amends the Federal Power Act, facilitates the transition to more competitive and efficient electric power markets, and for other purposes. Introduced by Senator Jeff Bingaman (D-NM) on October 8, 1997.
S. 1401 **"Transition to Electric Competition Act of 1997"**	Provides for the transition to competition among electric energy suppliers for the benefit and protection of consumers, and for other purposes. Jointly introduced by Senators Dale Bumpers (D-AR) and Slade Gorton (R-WA) on November 7, 1997.
S. 1483 **"To Amend the Internal Revenue Code of 1986 To Provide for the Treatment of Tax-exempt Bond Financing of Certain Electrical Output Facilities"**	Amends the Internal Revenue Code of 1986 to provide for the treatment of tax-exempt bond financing of certain electrical output facilities. Introduced by Senator Frank Murkowski (R-AK) on November 8, 1997.

- Congress should direct States to establish consumer choice programs by affirming that competition in retail markets is a matter of national policy. States should, however, be allowed to opt out where competition may be contrary to their own interests.
- Congress should eliminate impediments to competition resulting from the present structure of the PUHCA.
- Congress should establish a fresh policy for renewables, as the PURPA has outlived its usefulness.

- Congress should focus on reliability, because there is no clear Federal authority for establishing reliability standards for the electric utility industry.

- Congress should empower the FERC to address requirements on multi-State utilities that operate under conflicting retail access programs.

- Congress should also look into several other technical issues, such as clarifying the tax-exempt status of public utilities that may be called upon to provide open transmission access, determining the States' authority to require retail access and to provide for recovery of stranded costs and benefits, and the consideration of reciprocity issues.

Another study undertaken by the Congressional Research Service recommends a similar framework by raising the following issues:[221]

- Who should determine the boundaries and pace of restructuring efforts?

- How should transitional issues be handled?

- How should the market be structured to ensure a smoothly operating electric system in its hybrid competitive-regulated form?

- How should the electric utility be structured or restructured to encourage and safeguard a more competitive system?

- How should non-economic regulatory factors be integrated into the envisioned hybrid system?

Administration Proposal

The Administration released its *Comprehensive Electricity Competition Plan* in March 1998.[222] The plan advances legislative changes which aim to provide customer choice, enhance competition, and diversify generation sources. Key components include:[223]

- The plan 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, but would allow States or nonregulated utilities to opt out if they find that the consumers will be better served by an alternative policy. This approach strikes a balance between the need to spur competition and the preservation of State flexibility and authority.

- The plan includes a range of provisions to protect the environment through cleaner air and reduced greenhouse gas emissions while saving consumers money. These include a $3 billion *Public Benefits Fund,* to support conservation and energy efficiency, research and development into clean and efficient technology, and the deployment of renewable energy technologies; and a *Renewable Portfolio Standard,* to require that at least 5.5 percent of electricity sales be generated from non-hydroelectric renewable sources.

- The plan supports the principle that utilities must be able to recover prudently incurred, legitimate, and verifiable retail stranded costs arising from the transition to competition if these costs cannot be mitigated. States should continue to determine stranded cost recovery under State laws.

- Consumer information should be made available in a uniform and easy to understand manner through labeling. The Department of Energy would develop a system for requiring all electricity sellers to disclose prices and environmental attributes of their power supplies.

- With a view to strengthening electric system reliability, the plan builds upon the industry's tradition of self-regulation by requiring key market participants to join an organization that would establish reliability standards and enforce them, subject to oversight by the FERC.

- The plan aims to modernize Federal electricity law. This includes clarification of Federal jurisdiction by proposing amendments to the Federal Power Act to enable the FERC and the States to implement competition effectively. It provides the FERC with authority to order retail transmission, reinforces its jurisdiction over rates, terms, and conditions of unbundled retail transmission, and extends the applicability of its open access rules to municipal

[221] Congressional Research Service, *Electricity Restructuring: Overview of Basic Policy Questions* (Washington, DC, January 1997).
[222] U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 1998).
[223] Adopted from the fact sheet issued by the Department of Energy on the *Comprehensive Electricity Competition Plan* (March 25, 1998).

utilities, cooperatives, the Tennessee Valley Authority, and Federal power marketing administrations.

- The plan also clarifies States' jurisdiction to implement retail competition and to impose reciprocity requirements on extra-jurisdictional utilities.

- The "must buy" provisions of the PURPA and the entire PUHCA are to be repealed. The FERC's jurisdiction will be established over merger or consolidation of utility holding companies and generation companies.

- The FERC will also be authorized to remedy market power in wholesale markets, including ordering divestiture where necessary to mitigate market power.

- The plan gives the U.S. Environmental Protection Agency authority over interstate nitrogen oxide (NO_x) trading, so that NO_x reductions can be achieved cost-effectively.

- Among the miscellaneous issues, perhaps the most sensitive is the elimination of 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. Other issues deal with nuclear decommissioning costs and eliminating anti-trust review by the U.S. Nuclear Regulatory Commission.

Overall, the Administration expects that its proposals—by promoting competition—will combine long-run economic savings with environmental benefits.

States' Perspectives on Federal Legislation

States do not consider Federal legislation to be a requirement for promoting retail competition but concede that a carefully defined Federal framework would be useful in advancing the economic and social benefits of competitive markets. States seek Federal legislation in areas where jurisdictional conflicts are a possibility. Some States prefer that the role of Federal legislation be limited to eliminating impediments to the promotion of competition in electricity markets and that they should be left to craft restructuring proposals at their own pace to meet specific conditions prevailing in the States. Imposing a "date certain" by which competition must be in place in all States is not universally accepted. In no case should Federal legislation harm State initiatives or penalize States with unwanted Federal requirements.[224]

The National Association of Regulatory Utility Commissioners (NARUC), in its capacity as the national representative of State regulatory commissions, would like the Congress to resolve the following jurisdictional issues:[225]

- Whether States can implement a retail access/customer choice regime under the Federal Power Act

- Whether the FERC, or the States, has the jurisdiction to regulate rates, terms, and conditions of transmission services provided to retail customers on an unbundled basis

- Whether States can lawfully impose wires charges to support recovery of stranded costs, energy efficiency, or universal service programs.

NARUC also recommends that the States be allowed to form regional bodies to address transmission and system operation issues to ensure the reliability and sustainability of markets. It favors either a reform or repeal of PUHCA and a reform of PURPA legislation and supports the position that States should decide whether, when, and how to restructure local markets.

While NARUC's views enjoy wide support among State utility regulators, regulators in the northeastern States emphasize that restructuring should bring about an improvement in environmental performance of the industry. Their apprehension is that an increase in the use of coal in midwestern States would lead to increasing airborne pollution in their States. Low-cost States, such as Idaho, find it difficult to consider restructuring as a standalone economic issue (in view of the multiple uses of water used in generating electricity in the State) and would prefer to retain their independence in handling issues that are local and regional in nature. States such as California and others that have

[224] Testimony of Governor Angus S. King of Maine before the Committee on Energy and Natural Resources, United States Senate on the subject of *Competitive Change in the Electric Power Industry: Is Federal Legislation Necessary?* (March 20, 1997). A complete transcript of this hearing may be downloaded from the Committee's web page at www.senate.gov/~energy/competit3.htm.

[225] NARUC represents all State regulatory commissions charged with the responsibility of regulating the retail rates and services of electric, gas, water, and telephone utilities operating in their jurisdictions.

already enacted legislation prefer being "grandfathered" in any Federal legislation. Most States, however, prefer that Federal legislation should not attempt to set a specific date for commencement of competition at the retail level.[226]

Stakeholders' Perspectives on Federal Legislation

In addition to what the Federal legislation should achieve and the requirements of the States, there are other issues that merit consideration. For example, the opening of transmission lines on a nondiscriminatory basis and the required establishment of independent system operators will bring about a decline in the vertical market power exercised by incumbent utilities. Horizontal market power issues, however, remain and may be exacerbated by the wave of ongoing mergers and acquisitions in the industry. How to contain the growth of market power in the context of a continuing decline in the number of participating corporate entities owning transmission facilities poses a challenge.

Stakeholders in the restructuring debate—investor-owned utilities, public power representatives, Federal power marketing units, large industrial customers, small businesses, consumer advocacy groups, independent power producers, power marketers, natural gas and coal producers, and environmental and financial interests groups—representing diverse interests have contributed to the debate over the direction that Federal legislation should adopt. Since the interests of most groups are not always congruent, any proposed Federal legislation will be extremely complex and problematic.

Environmental issues have begun occupying the center stage in negotiating a consensus in the legislative process. The recognition that power generation using fossil fuels creates an unacceptable pollution level is nothing new. The renewed attention in this area stems from the recent mounting concerns associated with global warming issues, and the role that electricity generation can play in its mitigation through a process of partial internalization of known externalities.

The above difficulties partially explain why no Federal legislation has yet been enacted despite the number of bills pending in the Congress during the past 2 years. Senator Frank Murkowski, Chairman of the Senate Committee on Energy and Natural Resources, succinctly summarized the situation by saying "if we legislate, we must get it right the first time. There won't be a second chance."[227]

State Initiatives

States have a different and somewhat limited focus in the legislative arena. Lowering electricity prices is the single most critical element in the process. Reducing electricity prices in States like California and in the Northeast corridor has become a priority because of the perceived impact of electricity prices on regional economic development in general. It is, therefore, not surprising that States in which electricity prices are higher than the national average have spearheaded restructuring activities. Securing lower prices for all customer classes while providing options to choose their suppliers in retail electricity markets are the main objectives of the States.

In addition to the above primary objectives, States invariably have set related goals to be achieved in the process. For example, the New York Public Service Commission set the following goals:[228]

- Lowering rates for consumers
- Increasing customer choice
- Continuing reliability of service
- Continuing programs that are in the public interest
- Allaying concerns about market power
- Continuing customer protection and the obligation to serve.

Instituting operational modes to attain the above goals is challenging in view of the issues involved. Standards

[226] The entire Pennsylvania Congressional delegation sent a letter to Representative Tom Bliley, Chairman of the House Commerce Committee, endorsing a Federal date for State implementation of competition in electricity markets (Committee News Release, July 9, 1997). The following bills introduced during the 105th Congress include language stipulating a start date for commencement of retail wheeling in all States: H.R. 655, H.R. 1230, S. 237, and S. 1401.

[227] Comments by Senator Frank H. Murkowsky at the Electricity Workshop (March 6, 1997).

[228] New York Public Service Commission, Opinion No. 96-12, Case 94-E-0952 et al., *In the Matter of Competitive Opportunities Regarding Electric Service* (May 20, 1996).

for fair conduct need to be set up, questions of affiliate relationships may arise, market power issues need to be taken into account, and procedural requirements even for experimental measures need to be clearly defined. Agreement on some or all of these issues may be necessary for utilities to unbundle their rates and proceed further.

Some of the issues confronting the State legislatures are significantly different from those facing Federal lawmakers. They include:[229]

- Ensuring fair competition among electricity generators that must share the transmission and distribution grid

- Determining who pays for the costs of stranded assets of noncompetitive power generation

- Regulating local distribution systems and ensuring their reliable operation

- Evaluating the impact of competition on the fuel mix of power generation and assessing associated environmental impacts

- Defining the comparative role of renewables and fossil fuels in power generation.

States that have finalized plans for industry restructuring find that additional issues arise when competition is being implemented. Local authorities may be confronted with tax revenue losses as incumbent utilities exit or reduce their sales. New tax measures, if and when contemplated, may require new legislative mandates. Divestiture of generating assets—mandatory or voluntary—would be partial for utilities with nuclear generating units and would lengthen their recovery of related stranded costs. Ways and means may be designed to sustain assistance to low-income families, to reimburse utilities for demand-side management activities, and to ensure that protection offered by universal service does not dissipate as competition progresses. State regulators and legislators generally try to reach a consensus in finding solutions, but the process is time-consuming and the results are not always predictable. Differences resurface even after initial agreements have been worked out.

So far, 12 States have adopted major restructuring legislation (as of the end of June 1998).[230] Restructuring efforts have failed in 19 other States.[231] Many other States are still studying the problem to chart a course of action.

[229] National Governors' Association, *Issue Brief—Electric Industry Restructuring: Issues and Opportunities for States* (February 2, 1997).

[230] The States are: California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia. Note that Montana and Oklahoma are among the low-cost States to adopt competition.

[231] Refer to *Leap Letter*, Vol. 2 (November-December 1997).

Appendix A

Selected Provisions of The Energy Policy Act of 1992 and The Federal Power Act

Appendix A

Selected Provisions of the Energy Policy Act of 1992 (Public Law 102-486), Title VII—Electricity

Subtitle A—Exempt Wholesale Generators

SEC. 711. PUBLIC UTILITY HOLDING COMPANY ACT REFORM.

The Public Utility Holding Company Act of 1935 (15 U.S.C. 79 and following) is amended by redesignating sections 32 and 33 as sections 34 and 35 respectively and by adding the following new section after section 31:

"SEC. 32. EXEMPT WHOLESALE GENERATORS.

"(a) DEFINITIONS.—For purposes of this section—

"(1) EXEMPT WHOLESALE GENERATOR.—The term 'exempt wholesale generator' means any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly through one or more affiliates as defined in section 2(a)(11)(B), and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale. No person shall be deemed to be an exempt wholesale generator under this section unless such person has applied to the Federal Energy Regulatory Commission for a determination under this paragraph. A person applying in good faith for such a determination shall be deemed an exempt wholesale generator under this section, with all of the exemptions provided by this section, until the Federal Energy Regulatory Commission makes such determination. The Federal Energy Regulatory Commission shall make such determination within 60 days of its receipt of such application and shall notify the Commission whenever a determination is made under this paragraph that any person is an exempt wholesale generator. Not later than 12 months after the date of enactment of this section, the Federal Energy Regulatory Commission shall promulgate rules implementing the provisions of this paragraph. Applications for determination filed after the effective date of such rules shall be subject thereto.

"(2) ELIGIBLE FACILITY.—The term 'eligible facility' means a facility, wherever located, which is either—

"(A) used for the generation of electric energy exclusively for sale at wholesale, or

"(B) used for the generation of electric energy and leased to one or more public utility companies; *Provided*, That any such lease shall be treated as a sale of electric energy at wholesale for purposes of sections 205 and 206 of the Federal Power Act.

Such term shall not include any facility for which consent is required under subsection (c) if such consent has not been obtained. Such term includes interconnecting transmission facilities necessary to effect a sale of electric energy at wholesale. For purposes of this paragraph the term 'facility' may include a portion of a facility subject to the limitations of subsection (d) and shall include a facility the construction of which has not been commenced or completed.

"(3) SALE OF ELECTRIC ENERGY AT WHOLESALE.—The term 'sale of electric energy at wholesale' shall have the same meaning as provided in section 201(d) of the Federal Power Act (16 U.S.C. 824(d)).

"(4) RETAIL RATES AND CHARGES.—The term 'retail rates and charges' means rates and charges for the sale of electric energy directly to consumers.

"(b) FOREIGN RETAIL SALES.—Notwithstanding paragraphs (1) and (2) of subsection (a), retail sales of electric energy produced by a facility located in a foreign country shall not prevent such facility from being an eligible facility, or prevent a person owning or operating, or both owning and operating, such facility from being an exempt wholesale generator if none of the electric energy generated by such facility is sold to consumers in the United States.

"(c) STATE CONSENT FOR EXISTING RATE-BASED FACILITIES.— If a rate or charge for, or in connection with, the construction of a facility, or for electric energy produced by a facility (other than any portion of a rate or charge which represents recovery of the cost of a wholesale rate or charge) was in effect under the laws of any State as of the date of enactment of this section, in order for the facility to be considered an eligible facility, every State commission having jurisdiction over any such rate or charge must make a specific determination that allowing such facility to be an eligible facility (1) will benefit consumers, (2) is in the public interest, and (3) does not violate State law; *Provided,* That in the case of such a rate or charge which is a rate or charge of an affiliate of a registered holding company:

"(A) such determination with respect to the facility in question shall be required from every State commission having jurisdiction over the retail rates and charges of the affiliates of such registered holding company; and

"(B) the approval of the Commission under this Act shall not be required for the transfer of the facility to an exempt wholesale generator.

"(d) HYBRIDS.—(1) No exempt wholesale generator may own or operate a portion of any facility if any other portion of the facility is owned or operated by an electric utility company that is an affiliate or associate company of such exempt wholesale generator.

"(2) ELIGIBLE FACILITY.—Notwithstanding paragraph (1), an exempt wholesale generator may own or operate a portion of a facility identified in paragraph (1) if such portion has become an eligible facility as a result of the operation of subsection (c).

"(e) EXEMPTION OF EWGS.—An exempt wholesale generator shall not be considered an electric utility company under section 2(a)(3) of this Act and, whether or not a subsidiary company, an affiliate, or an associate company of a holding company, an exempt wholesale generator shall be exempt from all provisions of this Act.

"(f) OWNERSHIP OF EWGS BY EXEMPT HOLDING COMPANIES.— Notwithstanding any provision of this Act, a holding company that is exempt under section 3 of this Act shall be permitted, without condition or limitation under this Act, to acquire and maintain an interest in the business of one or more exempt wholesale generators.

"(g) OWNERSHIP OF EWGS BY REGISTERED HOLDING COMPANIES.— Notwithstanding any provision of this Act and the Commission's jurisdiction as provided under subsection (h) of this section, a registered holding company shall be permitted (without the need to apply for, or receive, approval from the Commission, and otherwise without condition under this Act) to acquire and hold the securities, or an interest in the business, of one or more exempt wholesale generators.

"(h) FINANCING AND OTHER RELATIONSHIPS BETWEEN EWGS AND REGISTERED HOLDING COMPANIES.—The issuance of securities by a registered holding company for purposes of financing the acquisition of an exempt wholesale generator, the guarantee of securities of an exempt wholesale generator by a registered holding company, the entering into service, sales or construction contracts, and the creation or maintenance of any other relationship in addition to that described in subsection (g) between an exempt wholesale generator and a registered holding company, its affiliates and associate companies, shall remain subject to the jurisdiction of the Commission under this Act: *Provided,* That—

"(1) section 11 of this Act shall not prohibit the ownership of an interest in the business of one or more exempt wholesale generators by a registered holding company (regardless of where facilities owned or operated by such exempt wholesale generators are located), and such ownership by a registered holding company shall be deemed consistent with the operation of an integrated public utility system;

"(2) the ownership of an interest in the business of one or more exempt wholesale generators by a registered holding company (regardless of where facilities owned or operated by such exempt wholesale generators are located) shall be considered as reasonably incidental, or economically necessary or appropriate, to the operations of an integrated public utility system;

"(3) in determining whether to approve (A) the issue or sale of a security by a registered holding company for purposes of financing the acquisition of an exempt wholesale generator, or (B) the guarantee of a security of an exempt wholesale generator by a registered holding company, the Commission shall not make a finding that such security is not reasonably adapted to the earning power of such company or to the security structure of such company and other companies in the same holding company system, or that the circumstances are such as to constitute the making of such guarantee an improper risk for such company, unless the Commission first finds that the issue or sale of such security, or the making of the guarantee, would have a substantial adverse impact on the financial integrity of the registered holding company system;

"(4) in determining whether to approve (A) the issue or sale of a security by a registered holding company for purposes other than the acquisition of an exempt wholesale generator or (B) other transactions by such registered holding company or by its subsidiaries other than with respect to exempt wholesale generators, the Commission shall not consider the effect of the capitalization or earnings of any subsidiary which is an exempt wholesale generator upon the registered holding company system, unless the approval of the issue or sale or other transaction, together with the effect of such capitalization and earnings, would have a substantial adverse impact on the financial integrity of the registered holding company system;

"(5) the Commission shall make its decision under paragraph (3) to approve or disapprove the issue or sale of a security or the guarantee of a security within 120 days of the filing of a declaration concerning such issue, sale or guarantee; and

"(6) the Commission shall promulgate regulations with respect to the actions which would be considered, for purposes of this subsection, to have a substantial adverse impact on the financial integrity of the registered holding company system; such regulations shall ensure that the action has no adverse impact on any utility subsidiary or its customers, or on the ability of State commissions to protect such subsidiary or customers, and shall take into account the amount and type of capital invested in exempt wholesale generators, the ratio of such capital to the total capital invested in utility operations, the availability of books and records, and the financial and operating experience of the registered holding company and the exempt wholesale generator; the Commission shall promulgate such regulations within 6 months after the enactment of this section, after such 6-month period the Commission shall not approve any actions under paragraph (3), (4) or (5) except in accordance with such issued regulations.

"(i) APPLICATION OF ACT TO OTHER ELIGIBLE FACILITIES.—In the case of any person engaged directly and exclusively in the business of owning or operating (or both owning and operating) all or part of one or more eligible facilities, an advisory letter issued by the Commission staff under this Act after the date of enactment of this section, or an order issued by the Commission under this Act after the date of enactment of this section, shall not be required for the purpose, or have the effect, of exempting such person from treatment as an electric utility company under section 2(a)(3) or exempting such person from any provision of this Act.

"(j) OWNERSHIP OF EXEMPT WHOLESALE GENERATORS AND QUALIFYING FACILITIES.—The ownership by a person of one or more exempt wholesale generators shall not result in such person being considered as being primarily engaged in the generation or sale of electric power within the meaning of sections 3(17)(C)(ii) and 3(18)(B)(ii) of the Federal Power Act (16 U.S.C. 796(17)(C)(ii) and 796(18)(B)(ii)).

"(k) PROTECTION AGAINST ABUSIVE AFFILIATE TRANSACTIONS.—

"(1) PROHIBITION.—After the date of enactment of this section, an electric utility company may not enter into a contract to purchase electric energy at wholesale from an exempt wholesale generator if the exempt wholesale generator is an affiliate or associate company of the electric utility company

"(2) STATE AUTHORITY TO EXEMPT FROM PROHIBITION.—Notwithstanding paragraph (1), an electric utility company may enter into a contract to purchase electric energy at wholesale from an exempt wholesale generator that is an affiliate or associate company of the electric utility company—

"(A) if every State commission having jurisdiction over the retail rates of such electric utility company makes each of the following specific determinations in advance of the electric utility company entering into such contract:

"(i) A determination that such commission has sufficient regulatory authority, resources and access to books and records of the electric utility company and any relevant associate, affiliate or subsidiary company to exercise its duties under this subparagraph.

"(ii) A determination that the transaction—

"(I) will benefit consumers,

"(II) does not violate any State law (including where applicable, least cost planning),

"(III) would not provide the exempt wholesale generator any unfair competitive advantage by virtue of its affiliation or association with the electric utility company, and

"(IV) is in the public interest; or

"(B) if such electric utility company is not subject to State commission retail rate regulation and the purchased electric energy:

"(i) would not be resold to any affiliate or associate company, or

"(ii) the purchased electric energy would be resold to an affiliate or associate company and every State commission having jurisdiction over the retail rates of such affiliate or associate company makes each of the determinations provided under subparagraph (A), including the determination concerning a State commission's duties.

"(l) RECIPROCAL ARRANGEMENTS PROHIBITED.—Reciprocal arrangements among companies that are not affiliates or associate companies of each other that are entered into in order to avoid the provisions of this section are prohibited.".

SEC. 712. STATE CONSIDERATION OF THE EFFECTS OF POWER PURCHASES ON UTILITY COST OF CAPITAL; CONSIDERATION OF THE EFFECTS OF LEVERAGED CAPITAL STRUCTURES ON THE RELIABILITY OF WHOLESALE POWER SELLERS; AND CONSIDERATION OF ADEQUATE FUEL SUPPLIES.

Section 111 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 and following) is amended by inserting the following new paragraph after paragraph (9):

"(10) CONSIDERATION OF THE EFFECTS OF WHOLESALE POWER PURCHASES ON UTILITY COST OF CAPITAL; EFFECTS OF LEVERAGED CAPITAL STRUCTURES ON THE RELIABILITY OF WHOLESALE POWER SELLERS; AND ASSURANCE OF ADEQUATE FUEL SUPPLIES.—(A) To the extent that a State regulatory authority requires or allows electric utilities for which it has ratemaking authority to consider the purchase of long-term wholesale power supplies as a means of meeting electric demand, such authority shall perform a general evaluation of:

"(i) the potential for increases or decreases in the costs of capital for such utilities, and any resulting increases or decreases in the retail rates paid by electric consumers, that may result from purchases of long-term wholesale power supplies in lieu of the construction of new generation facilities by such utilities;

"(ii) whether the use by exempt wholesale generators (as defined in section 32 of the Public Utility Holding Company Act of 1935) of capital structures which employ proportionally greater amounts of debt than the capital structures of such utilities threatens reliability or provides an unfair advantage for exempt wholesale generators over such utilities;

"(iii) whether to implement procedures for the advance approval or disapproval of the purchase of a particular long-term wholesale power supply; and

"(iv) whether to require as a condition for the approval of the purchase of power that there be reasonable assurances of fuel supply adequacy.

"(B) For purposes of implementing the provisions of this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

"(C) Notwithstanding any other provision of Federal law, nothing in this paragraph shall prevent a State regulatory authority from taking such action, including action with respect to the allowable capital structure of exempt wholesale generators, as such State regulatory authority may determine to be in the public interest as a result of performing evaluations under the standards of subparagraph (A).

"(D) Notwithstanding section 124 and paragraphs (1) and (2) of section 112(a), each State regulatory authority shall consider and make a determination concerning the standards of subparagraph (A) in accordance with the requirements of subsections (a) and (b) of this section, without regard to any proceedings commenced prior to the enactment of this paragraph.

"(E) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall consider and make a determination concerning whether it is appropriate to implement the standards set out in subparagraph (A) not later than one year after the date of enactment of this paragraph.".

SEC. 713. PUBLIC UTILITY HOLDING COMPANIES TO OWN INTERESTS IN COGENERATION FACILITIES.

Public Law 99-186 (99 Stat. 1180, as amended by Public Law 99-553, 100 Stat. 3087), is amended to read as follows:

"SECTION 1. Notwithstanding section 11(b)(1) of the Public Utility Holding Company Act of 1935, a company registered under said Act, or a subsidiary company of such registered company, may acquire or retain, in any geographic area, an interest in any qualifying cogeneration facilities and qualifying small power production facilities as defined pursuant to the Public Utility Regulatory Policies Act of 1978, and shall qualify for any exemption relating to the Public Utility Holding Company Act of 1935 prescribed pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978.

"SEC. 2. Nothing herein shall be construed to affect the applicability of section 3(17)(C) or section 3(18)(B) of the Federal Power Act or any provision of the Public Utility Holding Company Act of 1935, other than section 11(b)(1), to the acquisition or retention of any such interest by any such company.".

SEC. 714. BOOKS AND RECORDS.

Section 201 of the Federal Power Act is amended by adding the following new subsection at the end thereof:

"(g) BOOKS AND RECORDS.—(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of—

"(A) an electric utility company subject to its regulatory authority under State law,

"(B) any exempt wholesale generator selling energy at wholesale to such electric utility, and

"(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A), wherever located, if such examination is required for the effective discharge of the State commission's regulatory responsibilities affecting the provision of electric service.

"(2) Where a State commission issues an order pursuant to paragraph (1), the State commission shall not publicly disclose trade secrets or sensitive commercial information.

"(3) Any United States district court located in the State in which the State commission referred to in paragraph (1) is located shall have jurisdiction to enforce compliance with this subsection.

"(4) Nothing in this section shall—

"(A) preempt applicable State law concerning the provision of records and other information; or

"(B) in any way limit rights to obtain records and other information under Federal law, contracts, or otherwise.

"(5) As used in this subsection the terms 'affiliate,' 'associate company', 'electric utility company', 'holding company', 'subsidiary company', and 'exempt wholesale generator' shall have the same meaning as when used in the Public Utility Holding Company Act of 1935.".

SEC. 715. INVESTMENT IN FOREIGN UTILITIES.

The Public Utility Holding Company Act of 1935 (15 U.S.C. 79 et seq.) is amended by inserting after section 32 the following new section:

"SEC. 33. TREATMENT OF FOREIGN UTILITIES.

"(a) EXEMPTIONS FOR FOREIGN UTILITY COMPANIES.—

"(1) IN GENERAL.—A foreign utility company shall be exempt from all of the provisions of this Act, except as otherwise provided under this section, and shall not, for any purpose under this Act, be deemed to be a public utility company under section 2(a)(5), notwithstanding that the foreign utility company may be a subsidiary company, an affiliate, or an associate company of a holding company or of a public utility company.

"(2) STATE COMMISSION CERTIFICATION.—Section (a)(1) shall not apply or be effective unless every State commission having jurisdiction over the retail electric or gas rates of a public utility company that is an associate company or an affiliate of a company otherwise exempted under section (a)(1) (other than a public utility company that is an associate company or an affiliate of a registered holding company) has certified to the Commission that it has the authority and resources to protect ratepayers subject to its jurisdiction and that it intends to exercise its authority. Such certification, upon the filing of a notice by such State commission, may be revised or withdrawn by the State commission prospectively as to any future acquisition. The requirement of State certification shall be deemed satisfied if the relevant State commission had, prior to the date of enactment of this section, on the basis of prescribed conditions of general applicability, determined that ratepayers of a public utility company are adequately insulated from the effects of diversification and the diversification would not impair the ability of the State commission to regulate effectively the operations of such company.

"(3) DEFINITION.—For purposes of this section, the term 'foreign utility company' means any company that—

"(A) owns or operates facilities that are not located in any State and that are used for the generation, transmission, or distribution of electric energy for sale or the distribution at retail of natural or manufactured gas for heat, light, or power, if such company—

"(i) derives no part of its income, directly or indirectly, from the generation, transmission, or distribution of electric energy for sale or the distribution at retail of natural or manufactured gas for heat, light, or power, within the United States; and

"(ii) neither the company nor any of its subsidiary companies is a public utility company operating in the United States; and

"(B) provides notice to the Commission, in such form as the Commission may prescribe, that such company is a foreign utility company.

"(b) OWNERSHIP OF FOREIGN UTILITY COMPANIES BY EXEMPT HOLDING COMPANIES.—Notwithstanding any provision of this Act except as provided under this section, a holding company that is exempt under section 3 of the Act shall be permitted without condition or limitation under the Act to acquire and maintain an interest in the business of one or more foreign utility companies.

"(c) REGISTERED HOLDING COMPANIES.—

"(1) OWNERSHIP OF FOREIGN UTILITY COMPANIES BY REGISTERED HOLDING COMPANIES.—Notwithstanding any provision of this Act except as otherwise provided under this section, a registered holding company shall be permitted as of the date of enactment of this section (without the need to apply for or receive approval from the Commission) to acquire and hold the securities or an interest in the business, of one or more foreign utility companies. The Commission shall promulgate rules or regulations regarding registered holding companies' acquisition of interests in foreign utility companies which shall provide for the protection of the customers of a public utility company which is an associate company of a foreign utility company and the maintenance of the financial integrity of the registered holding company system.

"(2) ISSUANCE OF SECURITIES.—The issuance of securities by a registered holding company for purposes of financing the acquisition of a foreign utility company, the guarantee of securities of a foreign utility company by a registered holding company, the entering into service, sales, or construction contracts, and the creation or maintenance of any other relationship between a foreign utility company and a registered holding company, its affiliates and associate companies, shall remain subject to the jurisdiction of the Commission under this Act (unless otherwise exempted under this Act, in the case of a transaction with an affiliate or associate company located outside of the United States). Any State commission with jurisdiction over the retail rates of a public utility company which is part of a registered holding company system may make such recommendations to the Commission regarding the registered holding company's relationship to a foreign utility company, and the Commission shall reasonably and fully consider such State recommendation.

"(3) CONSTRUCTION.—Any interest in the business of 1 or more foreign utility companies, or 1 or more companies organized exclusively to own, directly or indirectly, the securities or other interest in a foreign utility company, shall for all purposes of this Act, be considered to be—

"(A) consistent with the operation of a single integrated public utility system, within the meaning of section 11; and

"(B) reasonably incidental, or economically necessary or appropriate, to the operations of an integrated public utility system, within the meaning of section 11.

"(d) EFFECT ON EXISTING LAW; NO STATE PREEMPTION.—Nothing in this section shall—

"(1) preclude any person from qualifying for or maintaining any exemption otherwise provided for under this Act or the rules, regulations, or orders promulgated or issued under this Act; or

"(2) be deemed or construed to limit the authority of any State (including any State regulatory authority) with respect to—

"(A) any public utility company or holding company subject to such State's jurisdiction; or

"(B) any transaction between any foreign utility company (or any affiliate or associate company thereof) and any public utility company or holding company subject to such State's jurisdiction.

"(e) REPORTING REQUIREMENTS.—

"(1) FILING OF REPORTS.—A public utility company that is an associate company of a foreign utility company shall file with the Commission such reports (with respect to such foreign utility company) as the Commission may by rules, regulations, or order prescribe as necessary or appropriate in the public interest or for the protection of investors or consumers.

"(2) NOTICE OF ACQUISITIONS.—Not later than 30 days after the consummation of the acquisition of an interest in a foreign utility company by an associate company of a public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates or by such public utility company, such associate company or such public utility company, shall provide notice of such acquisition to every State commission having jurisdiction over the retail electric or gas rates of such public utility company, in such form as may be prescribed by the State commission.

"(f) PROHIBITION ON ASSUMPTION OF LIABILITIES.—

"(1) IN GENERAL.—No public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates shall issue any security for the purpose of financing the acquisition, or for the purposes of financing the ownership or operation, of a foreign utility company, nor shall any such public utility company assume any obligation or liability as guarantor, endorser, surety, or otherwise in respect of any security of a foreign utility company.

"(2) EXCEPTION FOR HOLDING COMPANIES WHICH ARE PREDOMINANTLY PUBLIC UTILITY COMPANIES.—Subsection (f)(1) shall not apply if:

"(A) the public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates is a holding company and is not an affiliate under section 2(a)(11)(B) of another holding company or is not subject to regulation as a holding company and has no affiliate as defined in section 2(a)(11)(A) that is a public utility company subject to the jurisdiction of a State commission with respect to its retail electric or gas rates; and

"(B) each State commission having jurisdiction with respect to the retail electric and gas rates of such public utility company expressly permits such public utility to engage in a transaction otherwise prohibited under section (f)(1); and

"(C) the transaction (aggregated with all other then outstanding transactions exempted under this subsection) does not exceed 5 per centum of the then- outstanding total capitalization of the public utility.

"(g) PROHIBITION ON PLEDGING OR ENCUMBERING UTILITY ASSETS.—No public utility company that is subject to the jurisdiction of a State commission with respect to its retail electric or gas rates shall pledge or encumber any utility assets or utility assets of any subsidiary thereof for the benefit of an associate foreign utility company.".

Subtitle B — Federal Power Act; Interstate Commerce in Electricity

SEC. 721. AMENDMENTS TO SECTION 211 OF FEDERAL POWER ACT.

Section 211 of the Federal Power Act (16 U.S.C. 824j) is amended as follows:

(1) The first sentence of subsection (a) is amended to read as follows: "Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant.".

(2) In the second sentence of subsection (a), strike "the Commission may" and all that follows and insert "the Commission may issue such order if it finds that such order meets the requirements of section 212, and would otherwise be in the public interest. No order may be issued under this subsection unless the applicant has made a request for transmission services to the transmitting utility that would be the subject of such order at least 60 days prior to its filing of an application for such order.".

(3) Amend subsection (b) to read as follows:

"(b) RELIABILITY OF ELECTRIC SERVICE.—No order may be issued under this section or section 210 if, after giving consideration to consistently applied regional or national reliability standards, guidelines, or criteria, the Commission finds that such order would unreasonably impair the continued reliability of electric systems affected by the order.".

(4) In subsection (c)—

(A) Strike out paragraph (1).

(B) In paragraph (2) strike "which requires the electric" and insert "which requires the transmitting".

(C) Strike out paragraphs (3) and (4).

(5) In subsection (d)—

(A) In the first sentence of paragraph (1), strike "electric" and insert "transmitting" in each place it appears.

(B) In the second sentence of paragraph (1) before "and each affected electric utility," insert "each affected transmitting utility,".

(C) In paragraph (3), strike "electric" and insert "transmitting".

(D) Strike the period in subparagraph (B) of paragraph (1) and insert ", or" and after subparagraph (B) insert the following new subparagraph:

"(C) the ordered transmission services require enlargement of transmission capacity and the transmitting utility subject to the order has failed, after making a good faith effort, to obtain the necessary approvals or property rights under applicable Federal, State, and local laws.".

SEC. 722. TRANSMISSION SERVICES.

Section 212 of the Federal Power Act is amended as follows:

(1) Strike subsections (a) and (b) and insert the following:

"(a) RATES, CHARGES, TERMS, AND CONDITIONS FOR WHOLESALE TRANSMISSION SERVICES.—An order under section 211 shall require the transmitting utility subject to the order to provide wholesale transmission services at rates, charges, terms, and conditions which permit the recovery by such utility of all the costs incurred in connection with the transmission services and necessary associated services, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities. Such rates, charges, terms, and conditions shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable, and not unduly discriminatory or preferential. Rates, charges, terms, and conditions for transmission services provided pursuant to an order under section 211 shall ensure that to the extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for such order and not from a transmitting utility's existing wholesale, retail, and transmission customers.".

(2) Subsection (e) is amended to read as follows:

"(e) SAVINGS PROVISIONS.—(1) No provision of section 210, 211, 214, or this section shall be treated as requiring any person to utilize the authority of any such section in lieu of any other authority of law. Except as provided in section 210, 211, 214, or this section, such sections shall not be construed as limiting or impairing any authority of the Commission under any other provision of law.

"(2) Sections 210, 211, 213, 214, and this section, shall not be construed to modify, impair, or supersede the antitrust laws. For purposes of this section, the term 'antitrust laws' has the meaning given in subsection (a) of the first sentence of the Clayton Act, except that such term includes section 5 of the Federal Trade Commission Act to the extent that such section relates to unfair methods of competition.".

(3) Add the following new subsections at the end thereof:

"(g) PROHIBITION ON ORDERS INCONSISTENT WITH RETAIL MARKETING AREAS.—No order may be issued under this Act which is inconsistent with any State law which governs the retail marketing areas of electric utilities.

"(h) PROHIBITION ON MANDATORY RETAIL WHEELING AND SHAM WHOLESALE TRANSACTIONS.—No order issued under this Act shall be conditioned upon or require the transmission of electric energy:

"(1) directly to an ultimate consumer, or

"(2) to, or for the benefit of, an entity if such electric energy would be sold by such entity directly to an ultimate consumer, unless:

"(A) such entity is a Federal power marketing agency; the Tennessee Valley Authority; a State or any political subdivision of a State (or an agency, authority, or instrumentality of a State or a political subdivision); a corporation or association that has ever received a loan for the purposes of providing electric service from the Administrator of the Rural Electrification Administration under the Rural Electrification Act of 1936; a person having an obligation arising under State or local law (exclusive of an obligation arising solely from a contract entered into by such person) to provide electric service to the public; or any corporation or association which is wholly owned directly or indirectly, by any one or more of the foregoing; and

"(B) such entity was providing electric service to such ultimate consumer on the date of enactment of this subsection or would utilize transmission or distribution facilities that it owns or controls to deliver all such electric energy to such electric consumer.

Nothing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy directly to an ultimate consumer.".

"(i) LAWS APPLICABLE TO FEDERAL COLUMBIA RIVER TRANSMISSION SYSTEM.—(1) The Commission shall have authority pursuant to section 210, section 211, this section, and section 213 to (A) order the Administrator of the Bonneville Power Administration to provide transmission service and (B) establish the terms and conditions of such service. In applying such sections to the Federal Columbia River Transmission System, the Commission shall assure that—

"(i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and

"(ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 210, section 211, this section, or section 213, except that no rate for the transmission of power on the system shall be unjust unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

"(2) Notwithstanding any other provision of this Act with respect to the procedures for the determination of terms and conditions for transmission service—

"(A) when the Administrator of the Bonneville Power Administration either (I) in response to a written request for specific transmission service terms and conditions does not offer the requested terms and conditions, or (ii) proposes to establish terms and conditions of general applicability for transmission service on the Federal Columbia River Transmission System, then the Administrator may provide opportunity for a hearing and, in so doing, shall—

"(I) give notice in the Federal Register and state in such notice the written explanation of the reasons why the specific terms and conditions for transmission services are not being offered or are being proposed;

"(II) adhere to the procedural requirements of Paragraphs (1) through (3) of section 7(I) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839(I) (1) through (3)), except that the hearing officer shall, unless the hearing officer becomes unavailable to the agency, make a recommended decision to the Administrator that states the hearing officer's findings and conclusions, and the reasons or basis thereof, on all material issues of fact, law, or discretion presented on the record; and

"(III) make a determination, setting forth the reasons for reaching any findings and conclusions which may differ from those of the hearing officer, based on the hearing record, consideration of the hearing officer's recommended decision, section 211 and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section; and

"(B) if application is made to the Commission under section 211 for transmission service under terms and conditions different than those offered by the Administrator, or following the denial of a request for transmission service by the Administrator, and such application is filed within 60 days of the Administrator's final determination and in accordance with Commission procedures, the Commission shall—

"(i) in the event the Administrator has conducted a hearing as herein provided for (I) accord parties to the Administrator's hearing the opportunity to offer for the Commission record materials excluded by the Administrator from the hearing record, (II) accord such parties the opportunity to submit for the Commission record comments on appropriate terms and conditions, (III) afford those parties the opportunity for a hearing if and to the extent that the Commission finds the Administrator's hearing record to be inadequate to support a decision by the Commission, and (IV) establish terms and conditions for or deny transmission service based on the Administrator's hearing record, the Commission record, section 211 and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section, or

"(ii) in the event the Administrator has not conducted a hearing as herein provided for, determine whether to issue an order for transmission service in accordance with section 211 and this section, including providing the opportunity for a hearing.

"(3) Notwithstanding those provisions of section 313(b) of this Act (16 U.S.C. 825l) which designate the court in which review may be obtained, any party to a proceeding concerning transmission service sought to be furnished by the Administrator of the Bonneville Power Administration seeking review of an order issued by the Commission in such proceeding shall obtain a review of such order in the United States Court of Appeals for the Pacific Northwest, as that region is defined by section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)).

"(4) To the extent the Administrator of the Bonneville Power Administration cannot be required under section 211, as a result of the Administrator's other statutory mandates, either to (A) provide transmission service to an applicant which the Commission would otherwise order, or (B) provide such service under rates, terms, and conditions which the Commission would otherwise require, the applicant shall not be required to provide similar transmission services to the Administrator or to provide such services under similar rates, terms and conditions.

"(5) The Commission shall not issue any order under section 210, section 211, this section, or section 213 requiring the Administrator of the Bonneville Power Administration to provide transmission service if such an order would impair the Administrator's ability to provide such transmission service to the Administrator's power and transmission customers in the Pacific Northwest, as that region is defined in section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)), as is needed to assure adequate and reliable service to loads in that region.

"(j) EQUITABILITY WITHIN TERRITORY RESTRICTED ELECTRIC SYSTEMS.—With respect to an electric utility which is prohibited by Federal law from being a source of power supply, either directly or through a distributor of its electric energy, outside an area set forth in such law, no order issued under section 211 may require such electric utility (or a distributor of such electric utility) to provide transmission services to another entity if the electric energy to be transmitted will be consumed within the area set forth in such Federal law, unless the order is in furtherance of a sale of electric energy to that electric utility: *Provided, however,* That the foregoing provision shall not apply to any area served at retail by an electric transmission system which was such a distributor on the date of enactment of this subsection and which before October 1, 1991, gave its notice of termination under its power supply contract with such electric utility.

"(k) ERCOT UTILITIES.—

"(1) RATES.—Any order under section 211 requiring provision of transmission services in whole or in part within ERCOT shall provide that any ERCOT utility which is not a public utility and the transmission facilities of which are actually used for such transmission service is entitled to receive compensation based, insofar as practicable and consistent with subsection (a), on the transmission ratemaking methodology used by the Public Utility Commission of Texas.

"(2) DEFINITIONS.—For purposes of this subsection—

"(A) the term 'ERCOT' means the Electric Reliability Council of Texas; and

"(B) the term 'ERCOT utility' means a transmitting utility which is a member of ERCOT.".

SEC. 723. INFORMATION REQUIREMENTS.

Part II of the Federal Power Act is amended by adding the following new section after section 212:

"SEC. 213. INFORMATION REQUIREMENTS.

"(a) REQUESTS FOR WHOLESALE TRANSMISSION SERVICES.— Whenever any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale makes a good faith request to a transmitting utility to provide wholesale transmission services and requests specific rates and charges, and other terms and conditions, unless the transmitting utility agrees to provide such services at rates, charges, terms and conditions acceptable to such person, the transmitting utility shall, within 60 days of its receipt of the request, or other mutually agreed upon period, provide such person with a detailed written explanation, with specific reference to the facts and circumstances of the request, stating (1) the transmitting utility's basis for the proposed rates, charges, terms and conditions for such services and (2) its analysis of any physical or other constraints affecting the provision of such services.

"(b) TRANSMISSION CAPACITY AND CONSTRUCTS.—Not later than 1 year after the enactment of this section, the Commission shall promulgate a rule requiring that information be submitted annually to the Commission by transmitting utilities which is adequate to inform potential transmission customers, State regulatory authorities, and the public of potentially available transmission capacity and known constraints.".

SEC. 724. SALES BY EXEMPT WHOLESALE GENERATORS.

Part II of the Federal Power Act is amended by adding the following new section after section 213:

"SEC. 214. SALES BY EXEMPT WHOLESALE GENERATORS.

"No rate or charge received by an exempt wholesale generator for the sale of electric energy shall be lawful under section 205 if, after notice and opportunity for hearing, the Commission finds that such rate or charge results from the receipt of any undue preference or advantage from an electric utility which is an associate company or an affiliate of the exempt wholesale generator. For purposes of this section, the terms 'associate company' and 'affiliate' shall have the same meaning as provided in section 2(a) of the Public Utility Holding Company Act of 1935.".

SEC. 725. PENALTIES.

(a) EXISTING PENALTIES NOT APPLICABLE TO TRANSMISSION PROVISIONS.—Sections 315 and 316 of the Federal Power Act are each amended by adding the following at the end thereof:

"(c) This subsection shall not apply in the case of any provision of section 211, 212, 213, or 214 or any rule or order issued under any such provision.".

(b) PENALTIES APPLICABLE TO TRANSMISSION PROVISIONS.—Title III of the Federal Power Act is amended by inserting the following new section after section 316:

"SEC. 316A. ENFORCEMENT OF CERTAIN PROVISIONS.

"(a) VIOLATIONS.—It shall be unlawful for any person to violate any provision of section 211, 212, 213, or 214 or any rule or order issued under any such provision.

"(b) CIVIL PENALTIES.—Any person who violates any provision of section 211, 212, 213, or 214 or any provision of any rule or order thereunder shall be subject to a civil penalty of not more than $10,000 for each day that such violation continues. Such penalty shall be assessed by the Commission, after notice and opportunity for public hearing, in accordance with the same provisions as are applicable under section 31(d) in the case of civil penalties assessed under section 31. In determining the amount of a proposed penalty, the Commission shall take into consideration the seriousness of the violation and the efforts of such person to remedy the violation in a timely manner.".

SEC. 726. DEFINITIONS.

(a) ADDITIONAL DEFINITIONS.—Section 3 of the Federal Power Act is amended by adding the following at the end thereof:

"(23) TRANSMITTING UTILITY.—The term 'transmitting utility' means any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.

"(24) WHOLESALE TRANSMISSION SERVICES.—The term 'wholesale transmission services' means the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.

"(25) EXEMPT WHOLESALE GENERATOR.—The term 'exempt wholesale generator' shall have the meaning provided by section 32 of the Public Utility Holding Company Act of 1935.".

(b) CLARIFICATION OF TERMS.—Section 3(22) of the Federal Power Act is amended by inserting "(including any municipality)" after "State agency".

Subtitle C—State and Local Authorities

SEC. 731. STATE AUTHORITIES.

Nothing in this title or in any amendment made by this title shall be construed as affecting or intending to affect, or in any way to interfere with, the authority of any State or local government relating to environmental protection or the siting of facilities.

Selected Provisions of the Federal Power Act

RATE AND CHARGES; SCHEDULES; SUSPENSION OF NEW RATES

SEC. 205. (a) All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classification, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Unless the Commission otherwise orders, no change shall be made by any public utility in any such rates, charges, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f)(1) Not later than 2 years after the date of the enactment of this subsection and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations, and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing,

order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause, if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.
(16 U.S.C. 824d)

FIXING RATES AND CHARGES; DETERMINATION OF COST OF PRODUCTION OR TRANSPORTATION

SEC. 206. (a) Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charges, or classification demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

(b) Whenever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date 60 days after the filing of such complaint nor later than 5 months after the expiration of such 60-day period. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date 60 days after the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the expiration of such 60-day period. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 205 of this Act and otherwise act as speedily as possible. If no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order the public utility to make refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided*, That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Notwithstanding subsection (b), in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding company: *Provided*, That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company would not experience any reduction in revenues which results from an inability of an electric utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended.

(d) The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.
(16 U.S.C. 824i)

CERTAIN WHEELING AUTHORITY

SEC. 211. (a) Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant. Upon receipt of such application, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such order if it finds that such order meets the requirements of section 212, and would otherwise be in the public interest. No order may be issued under this subsection unless the applicant has made a request for transmission services to the transmitting utility that would be the subject of such order at least 60 days prior to its filing of an application for such order.

(b) RELIABILITY OF ELECTRIC SERVICE.—No order may be issued under this section or section 210 if, after giving consideration to consistently applied regional or national reliability standards, guidelines, or criteria, the Commission finds that such order would unreasonably impair the continued reliability of electric systems affected by the order.

(c)(2)[232] No order may be issued under subsection (a) or (b) which requires the transmitting utility subject to the order to transmit, during any period, an amount of electric energy which replaces any amount of electric energy—

(A) required to be provided to such applicant pursuant to a contract during such period, or

(B) currently provided to the applicant by the utility subject to the order pursuant to a rate schedule on file during such period with the Commission: *Provided,* That nothing in this subparagraph shall prevent an application for an order hereunder to be filed prior to termination of modification of an existing rate schedule: *Provided,* That such order shall not become effective until termination of such rate schedule or the modification becomes effective.

(d)(1) Any transmitting utility ordered under subsection (a) or (b) to provide transmission services may apply to the Commission for an order permitting such transmitting utility to cease providing all, or any portion of, such services. After public notice, notice to each affected State regulatory authority, each affected Federal power marketing agency, each affected transmitting utility, and each affected electric utility, and after an opportunity for an evidentiary hearing, the Commission shall issue an order terminating or modifying the order issued under subsection (a) or (b), if the electric utility providing such transmission services has demonstrated, and the Commission has found, that—

(A) due to changed circumstances, the requirements applicable, under this section and section 212, to the issuance of an order under subsection (a) or (b) are no longer met, or

(B) any transmission capacity of the utility providing transmission services under such order which was, at the time such order was issued, in excess of the capacity necessary to serve its own customers is no longer in excess of the capacity necessary for such purposes, or

(c) the ordered transmission services require enlargement of transmission capacity and the transmitting utility subject to the order has failed, after making a good faith effort, to obtain the necessary approvals or property rights under applicable Federal, State, and local laws.

No order shall be issued under this subsection pursuant to a finding under subparagraph (A) unless the Commission finds that such order is in the public interest.

(2) Any order issued under this subsection terminating or modifying an order issued under subsection (a) or (b) shall—

(A) provide for any appropriate compensation, and

(B) provide the affected electric utilities adequate opportunity and time to—

(i) make suitable alternative arrangements for any transmission services terminated or modified, and

(ii) insure that the interests of ratepayers of such utilities are adequately protected.

(3) No order may be issued under this subsection terminating or modifying any order issued under subsection (a) or (b) if the order under subsection (a) or (b) includes terms and conditions agreed among by the parties which—

(A) fix a period during which transmission services are to be provided under the order under subsection (a) or (b), or

(B) otherwise provide procedures or methods for terminating or modifying such order (including, if appropriate, the return of the transmission capacity when necessary to take into account an increase, after the issuance of such order, in the needs of the transmitting utility subject to such order for transmission capacity).

(e) As used in this section, the term "facilities" means only facilities used for the generation or transmission of electric energy.

(16 U.S.C. 824j)

[232]Section 721(4) of P.L. 102-486 struck paragraphs (1), (3), and (4) without redesignating paragraph (2).

PROVISIONS REGARDING CERTAIN ORDERS REQUIRING INTERCONNECTION OR WHEELING

SEC. 212. (a) RATES, CHARGES, TERMS, AND CONDITIONS FOR WHOLESALE TRANSMISSION SERVICES.—An order under section 211 shall require the transmitting utility subject to the order to provide wholesale transmission services at rates, charges, terms, and conditions which permit the recovery by such utility of all the costs incurred in connection with the transmission services and necessary associated services, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities. Such rates, charges, terms, and conditions shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable, and not unduly discriminatory or preferential. Rates, charges, terms, and conditions for transmission services provided pursuant to an order under section 211 shall ensure that, to the extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for such order and not from a transmitting utility's existing wholesale, retail, and transmission customers.

[Subsection (b) repealed]

(c)(1) Before issuing an order under section 210 of subsection (a) or (b) of section 211, the Commission shall issue a proposed order and set a reasonable time for parties to the proposed interconnection or transmission order to agree to terms and conditions under which such order is to be carried out, including the apportionment of costs between them and the compensation or reimbursement reasonably due to any of them. Such proposed order shall not be reviewable or enforceable in any court. The time set for such parties to agree to such terms and conditions may be shortened if the Commission determines that delay would jeopardize the attainment of the purposes of any proposed order. Any terms and conditions agreed to by the parties shall be subject to the approval of the Commission.

(2)(A) If the parties agree as provided in paragraph (1) within the time set by the Commission and the Commission approves such agreement, the terms and conditions shall be included in the final order. In the case of an order under section 210, if the parties fail to agree within the time set by the Commission or if the Commission does not approve any such agreement, the Commission shall prescribe such terms and conditions and include such terms and conditions in the final order.

(B) In the case of any order applied for under section 211, if the parties fail to agree within the time set by the Commission, the Commission shall prescribe such terms and conditions in the final order.

(d) If the Commission does not issue any order applied for under section 210 or 211, the Commission shall, by order, deny such application and state the reasons for such denial.

(e) SAVINGS PROVISIONS.—(1) No provision of section 210, 211, 214, or this section shall be treated as requiring any person to utilize the authority of any such section in lieu of any other authority of law. Except as provided in section 210, 211, 214, or this section, such sections shall not be construed as limiting or impairing any authority of the Commission under any other provision of law.

(2) Sections 210, 211, 213, 214, and this section, shall not be construed to modify, impair, or supersede the antitrust laws. For purposes of this section, the term "antitrust laws" has the meaning given in subsection (a) of the first sentence of the Clayton Act, except that such term includes section 5 of the Federal Trade Commission Act to the extent that such section relates to unfair methods of competition.

(f)(1) No order under section 210 or 211 requiring the Tennessee Valley Authority (hereinafter in this subsection referred to as the "TVA") to take any action shall take effect for 60 days following the date of issuance of the order. Within 60 days following the issuance by the Commission of any order under section 210 or of section 211 requiring the TVA to enter into any contract for the sale or delivery of power, the Commission may on its own motion initiate, or upon petition of any aggrieved person shall initiate, an evidentiary hearing to determine whether or not such sale or delivery would result in violation of the third sentence of section 15d(a) of the Tennessee Valley Authority Act of 1933 (16 U.S.C. 831n—4), hereinafter in this subsection referred to as the TVA Act.

(2) Upon initiation of any evidentiary hearing under paragraph (1), the Commission shall give notice thereof to any applicant who applied for and obtained the order from the Commission, to any electric utility or other entity subject to such order, and to the public, and shall promptly make the determination referred to in paragraph (1). Upon initiation of such hearing, the Commission shall stay the effectiveness of the order under section 210 or 211 until whichever of the following dates is applicable—

(A) the date on which there is a final determination (including any judicial review thereof under paragraph (3)) that no such violation would result from such order, or

(B) the date on which a specific authorization of the Congress (within the meaning of the third sentence of section 15d(a) of the TVA Act) takes effect.

(3) Any determination under paragraph (1) shall be reviewable only in the appropriate court of the United States upon petition filed by any aggrieved person or municipality within 60 days after such determination, and such court shall have jurisdiction to grant appropriate relief. Any applicant who applied for and obtained the order under section 210 or 211, and any electric utility or other entity subject to such order shall have the right to intervene in and such proceeding in such

court. Except for review by such court (and any appeal or other review by an appellate court of the United States), no court shall have jurisdiction to consider any action brought by any person to enjoin the carrying out of any order of the Commission under section 210 or section 211 requiring the TVA to take any action on the grounds that such action requires a specific authorization of the Congress pursuant to the third sentence of section 15d(a) of the TVA Act.

(g) PROHIBITION ON ORDERS INCONSISTENT WITH RETAIL MARKETING AREAS.—No order may be issued under this Act which is inconsistent with any State law which governs the retail marketing areas of electric utilities.

(h) PROHIBITION ON MANDATORY RETAIL WHEELING AND SHAM WHOLESALE TRANSACTIONS.—No order issued under this Act shall be conditioned upon or require the transmission of electric energy:

(1) directly to an ultimate consumer, or

(2) to, or for the benefit of, an entity if such electric energy would be sold by such entity directly to an ultimate consumer, unless:

(A) such entity is a Federal power marketing agency; the Tennessee Valley Authority; a State or any political subdivision of a State (or an agency, authority, or instrumentality of a State or a political subdivision); a corporation or association that has ever received a loan for the purposes of providing electric service from the Administrator of the Rural Electrification Administration under the Rural Electrification Act of 1936; a person having an obligation arising under State or local law (exclusive of an obligation arising solely from a contract entered into by such person) to provide electric service to the public; or any corporation or association which is wholly owned, directly or indirectly, by any one or more of the foregoing; and

(B) such entity was providing electric service to such ultimate consumer on the date of enactment of this subsection or would utilize transmission or distribution facilities that it owns or controls to deliver all such electric energy to such electric consumer.

Nothing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy directly to an ultimate consumer.

(i) LAWS APPLICABLE TO FEDERAL COLUMBIA RIVER TRANSMISSION SYSTEM.—(1) The Commission shall have authority pursuant to section 210, section 211, this section, and section 213 to (A) order the Administrator of the Bonneville Power Administration to provide transmission service and (B) establish the terms and conditions of such service. In applying such sections to the Federal Columbia River Transmission System, the Commission shall assure that—

(i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and

(ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 210, section 211, this section, or section 213, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

(2) Notwithstanding any other provision of this Act with respect to the procedures for the determination of terms and conditions for transmission service—

(A) when the Administrator of the Bonneville Power Administration either (I) in response to a written request for specific transmission service terms and conditions does not offer the requested terms and conditions, or (ii) proposes to establish terms and conditions of general applicability for transmission service on the Federal Columbia River Transmission System, then the Administrator may provide opportunity for a hearing and, in so doing, shall—

(I) give notice in the Federal Register and state in such notice the written explanation of the reasons why the specific terms and conditions for transmission services are not being offered or are being proposed;

(II) adhere to the procedural requirements of paragraphs (1) through (3) of section 7(I) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839(I) (1) through (3)), except that the hearing officer shall, unless the hearing officer becomes unavailable to the agency, make a recommended decision to the Administrator that states the hearing officer's findings and conclusions, and the reasons or basis thereof, on all material issues of fact, law, or discretion presented on the record; and

(III) make a determination, setting forth the reasons for reaching any findings and conclusions which may differ from those of the hearing officer, based on the hearing record, consideration of the hearing officer's recommended decision, section 211 and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section; and

(B) if application is made to the Commission under section 211 for transmission service under terms and conditions different than those offered by the Administrator, or following the denial of a request for transmission service by the Administrator, and such application is filed within 60 days of the Administrator's final determination and in accordance with Commission procedures, the Commission shall—

(i) in the event the Administrator has conducted a hearing as herein provided for (I) accord parties to the Administrator's hearing the opportunity to offer for the Commission record materials excluded by the Administrator from the hearing record, (II) accord such parties the opportunity to submit for the Commission record comments on appropriate terms and conditions, (III) afford those parties the opportunity for a hearing if and to the extent that the Commission finds the Administrator's hearing record to be inadequate to support a decision by the Commission, and (IV) establish terms and conditions for or deny transmission service based on the Administrator's hearing record, the Commission record, section 211 and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section, or

(ii) in the event the Administrator has not conducted a hearing as herein provided for, determine whether to issue an order for transmission service in accordance with section 211 and this section, including providing the opportunity for a hearing.

(3) Notwithstanding those provisions of section 313(b) of this Act (16 U.S.C. 825l) which designate the court in which review may be obtained, any party to a proceeding concerning transmission service sought to be furnished by the Administrator of the Bonneville Power Administration seeking review of an order issued by the Commission in such proceeding shall obtain a review of such order in the United States Court of Appeals for the Pacific Northwest, as that region is defined by section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)).

(4) To the extent the Administrator of the Bonneville Power Administration cannot be required under section 211, as a result of the Administrator's other statutory mandates, either to (A) provide transmission service to an applicant which the Commission would otherwise order, or (B) provide such service under rates, terms, and conditions which the Commission would otherwise require, the applicant shall not be required to provide similar transmission services to the Administrator or to provide such services under similar rates, terms, and conditions.

(5) The Commission shall not issue any order under section 210, section 211, this section, or section 213 requiring the Administrator of the Bonneville Power Administration to provide transmission service if such an order would impair the Administrator's ability to provide such transmission service to the Administrator's power and transmission customers in the Pacific Northwest, as that region is defined in section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)), as is needed to assure adequate and reliable service to loads in that region.

(j) EQUITABILITY WITHIN TERRITORY RESTRICTED ELECTRIC SYSTEMS.—With respect to an electric utility which is prohibited by Federal law from being a source of power supply, either directly or through a distributor of its electric energy, outside an area set forth in such law, no order issued under section 211 may require such electric utility (or a distributor of such electric utility) to provide transmission services to another entity if the electric energy to be transmitted will be consumed within the area set forth in such Federal law, unless the order is in furtherance of a sale of electric energy to that electric utility: *Provided, however,* That the foregoing provision shall not apply to any area served at retail by an electric transmission system which was such a distributor on the date of enactment of this subsection and which before October 1, 1991, gave its notice of termination under its power supply contract with such electric utility.

(k) ERCOT UTILITIES.—

(1) RATES.—Any order under section 211 requiring provision of transmission services in whole or in part within ERCOT shall provide that any ERCOT utility which is not a public utility and the transmission facilities of which are actually used for such transmission service is entitled to receive compensation based, insofar as practicable and consistent with subsection (a), on the transmission ratemaking methodology used by the Public Utility Commission of Texas.

(2) DEFINITIONS.—For purposes of this subsection—

(A) the term "ERCOT" means the Electric Reliability Council of Texas; and

(B) the term "ERCOT utility" means a transmitting utility which is a member of ERCOT.

(16 U.S.C. 824k)

Appendix B

Average Revenue per Kilowatthour by Sector, 1988-1996

Table B1. Average Revenue Per Kilowatthour for Industrial Customers, 1988-1996 (Cents)

Census Division	1988	1989	1990	1991	1992	1993	1994	1995	1996
New England	6.53	6.90	7.40	7.90	8.10	8.26	8.12	8.04	7.92
Middle Atlantic	5.54	5.80	6.10	6.50	6.60	6.58	6.53	6.24	6.19
East North Central	4.57	4.50	4.60	4.70	4.70	4.56	4.45	4.45	4.43
West North Central	4.45	4.40	4.40	4.40	4.40	4.44	4.40	4.32	4.24
South Atlantic	4.49	4.50	4.60	4.70	4.70	4.72	4.61	4.47	4.35
East South Central	4.85	4.60	4.30	4.10	4.10	4.16	4.03	3.91	3.86
West South Central	4.10	4.10	4.10	4.20	4.20	4.38	4.27	4.02	4.11
Mountain	4.15	4.10	4.10	4.20	4.20	4.29	4.34	4.20	4.11
Pacific Contiguous	4.93	5.00	4.90	5.10	5.10	5.10	5.25	5.39	5.23
Pacific Noncontiguous	6.37	6.70	7.60	7.80	7.80	8.86	8.76	9.16	9.82
U.S. Average	**4.70**	**4.70**	**4.70**	**4.80**	**4.80**	**4.85**	**4.77**	**4.66**	**4.60**

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

Table B2. Average Revenue Per Kilowatthour for Residential Customers, 1988-1996 (Cents)

Census Division	1988	1989	1990	1991	1992	1993	1994	1995	1996
New England	8.79	9.20	9.80	10.40	10.90	11.24	11.43	11.74	11.82
Middle Atlantic	9.62	9.90	10.30	10.80	11.00	11.34	11.51	11.79	11.84
East North Central	7.90	8.00	8.10	8.20	8.30	8.34	8.37	8.48	8.47
West North Central	7.10	7.10	7.20	7.20	7.30	7.27	7.32	7.33	7.23
South Atlantic	7.24	7.30	7.50	7.60	7.70	7.84	7.82	7.87	7.84
East South Central	6.03	6.10	6.10	6.10	6.20	6.24	6.25	6.23	6.19
West South Central	6.96	7.10	7.20	7.50	7.70	7.89	7.88	7.56	7.61
Mountain	7.23	7.20	7.30	7.30	7.60	7.60	7.66	7.62	7.58
Pacific Contiguous	6.93	7.40	7.80	8.20	8.60	8.59	8.89	9.00	8.85
Pacific Noncontiguous	9.19	9.50	10.20	10.60	10.90	11.83	12.00	12.50	13.11
U.S. Average	**7.48**	**7.60**	**7.80**	**8.00**	**8.20**	**8.32**	**8.38**	**8.40**	**8.36**

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

Table B3. Average Revenue Per Kilowatthour for Commercial Customers, 1988-1996 (Cents)

Census Division	1988	1989	1990	1991	1992	1993	1994	1995	1996
New England	7.88	8.20	8.70	9.30	9.60	9.85	9.94	10.18	10.19
Middle Atlantic	8.75	9.00	9.40	9.70	9.90	10.15	10.17	10.43	10.51
East North Central	7.04	7.20	7.30	7.40	7.40	7.39	7.32	7.34	7.37
West North Central	6.30	6.30	6.30	6.30	6.30	6.31	6.26	6.25	6.19
South Atlantic	6.47	6.50	6.60	6.60	6.70	6.70	6.56	6.58	6.60
East South Central	6.24	6.30	6.30	6.30	6.40	6.51	6.40	6.34	6.27
West South Central	6.14	6.20	6.30	6.60	6.80	6.93	6.94	6.58	6.68
Mountain	6.49	6.50	6.50	6.50	6.60	6.70	6.68	6.63	6.53
Pacific Contiguous	7.46	7.80	8.10	8.50	8.70	8.80	9.10	8.86	8.40
Pacific Noncontiguous	8.63	9.00	9.60	9.80	10.00	10.69	10.75	10.99	11.45
U.S. Average	**7.04**	**7.20**	**7.30**	**7.50**	**7.70**	**7.74**	**7.73**	**7.69**	**7.64**

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

Table B4. Average Revenue Per Kilowatthour for Other Customers, 1988-1996 (Cents)

Census Division	1988	1989	1990	1991	1992	1993	1994	1995	1996
New England	10.09	10.60	11.20	12.00	12.00	12.66	13.02	13.94	14.39
Middle Atlantic	7.89	8.30	8.50	8.50	9.30	9.65	9.79	9.60	9.66
East North Central	6.45	6.70	6.90	6.90	7.00	7.04	6.79	6.94	6.98
West North Central	6.04	5.90	6.10	6.20	6.50	6.45	6.49	6.29	6.41
South Atlantic	6.14	6.00	6.20	6.30	6.40	6.41	6.41	6.23	6.29
East South Central	5.87	5.60	5.70	5.70	5.80	5.95	5.95	6.03	6.04
West South Central	6.17	6.20	6.30	6.20	6.30	6.65	6.59	6.32	6.46
Mountain	5.21	5.20	5.40	5.70	5.50	5.68	5.62	5.65	5.68
Pacific Contiguous	4.52	4.10	4.10	4.50	4.80	4.63	4.67	5.57	5.43
Pacific Noncontiguous	11.90	11.90	12.20	11.50	13.00	12.41	12.24	12.97	13.23
U.S. Average	**6.20**	**6.20**	**6.40**	**6.50**	**6.70**	**6.88**	**6.84**	**6.88**	**6.91**

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

Table B5. Average Revenue Per Kilowatthour for Total Customers, 1988-1996 (Cents)

Census Division	1988	1989	1990	1991	1992	1993	1994	1995	1996
New England	7.89	8.30	8.80	9.40	9.70	10.01	10.09	10.27	10.28
Middle Atlantic	8.00	8.30	8.70	9.10	9.20	9.50	9.57	9.71	9.76
East North Central	6.24	6.30	6.40	6.50	6.50	6.50	6.41	6.47	6.48
West North Central	5.98	5.90	6.00	6.00	6.00	6.04	6.01	5.99	5.91
South Atlantic	6.19	6.20	6.40	6.50	6.50	6.61	6.54	6.57	6.54
East South Central	5.51	5.40	5.30	5.20	5.10	5.22	5.14	5.07	5.04
West South Central	5.70	5.80	5.80	6.10	6.10	6.34	6.29	6.00	6.08
Mountain	5.89	5.90	5.90	6.00	6.00	6.15	6.15	6.06	6.00
Pacific Contiguous	6.33	6.70	6.80	7.10	7.40	7.43	7.65	7.74	7.54
Pacific Noncontiguous	8.08	8.50	9.20	9.40	9.60	10.48	10.54	10.92	11.49
U.S. Average	**6.35**	**6.50**	**6.60**	**6.70**	**6.80**	**6.93**	**6.91**	**6.89**	**6.86**

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

Appendix C

Data on Electric Trade in the United States, 1996

Table C1. U.S. Electric Utility Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1996

Item	Residential	Commercial	Industrial	Other [1]	All Sectors
Sales (million kilowatthours)......	1,082,491	887,425	1,030,356	97,539	3,097,810
Revenue (thousand dollars).........	90,501,156	67,826,638	47,385,427	6,741,353	212,454,574
U.S. Average (cents)	8.36	7.64	4.60	6.91	6.86

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

Table C2. U.S. Electric Utilities Having No Generating Production and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1996

Item	Residential	Commercial	Industrial	Other [1]	All Sectors
Sales (million kilowatthours)......	231,927	85,114	136,487	11,293	464,821
Revenue (thousand dollars).........	16,750,794	6,018,026	6,433,324	777,528	29,979,672
U.S. Average (cents)	7.22	7.07	4.71	6.89	6.45

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

Table C3. U.S. Electric Utilities Producing 25 Percent or Less of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1996

Item	Residential	Commercial	Industrial	Other [1]	All Sectors
Sales (million kilowatthours)......	3,531	3,026	47,378	4,440	58,374
Revenue (thousand dollars).........	172,759	145,227	1,203,419	110,477	1,631,882
U.S. Average (cents)	4.89	4.80	2.54	2.49	2.80

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

Table C4. U.S. Electric Utilities Producing Greater Than 25 Percent of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1996

Item	Residential	Commercial	Industrial	Other [1]	All Sectors
Sales (million kilowatthours)	847,033	799,285	846,491	81,806	2,574,615
Revenue (thousand dollars)	73,577,603	61,663,385	39,748,684	5,853,348	180,843,020
U.S. Average (cents)	8.69	7.71	4.70	7.16	7.02

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

Table C5. U.S. Electric Utility Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership and Sector, 1996
(Million Kilowatthours)

Item	Residential	Commercial	Industrial	Other[1]	All Sectors
Sales (million kilowatthours)					
Investor-Owned	770,879	731,668	777,164	63,098	2,342,808
Publicly Owned	158,492	114,901	153,517	24,018	450,928
Cooperative	152,825	40,682	58,625	6,315	258,448
Federal	295	173	41,050	4,108	45,626
U.S. Total	1,082,491	887,425	1,030,356	97,539	3,097,810
Revenue (thousand dollars)					
Investor-Owned	68,344,395	57,264,573	36,619,448	4,567,201	166,795,617
Publicly Owned	10,627,715	7,617,706	7,201,653	1,650,951	27,098,025
Cooperative	11,509,786	2,932,257	2,537,201	429,663	17,408,907
Federal	19,260	12,102	1,027,125	93,538	1,152,025
U.S. Total	90,501,156	67,826,638	47,385,427	6,741,353	212,454,574
Average Revenue per Kilowatthour (cents)					
Investor-Owned	8.87	7.83	4.71	7.24	7.12
Publicly Owned	6.71	6.63	4.69	6.87	6.01
Cooperative	7.53	7.21	4.33	6.80	6.74
Federal	6.52	6.99	2.50	2.28	2.52
U.S. Average	8.36	7.64	4.60	6.91	6.86

[1] Includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data are final. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table C6. U.S. Electric Utilities Having No Generating Production and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership and Sector, 1996
(Million Kilowatthours)

Item	Residential	Commercial	Industrial	Other[1]	All Sectors
Sales (million kilowatthours)					
Investor-Owned	12,106	11,435	8,770	876	33,187
Publicly Owned	70,973	35,427	72,848	4,435	183,683
Cooperative	148,753	38,187	54,770	5,950	247,660
Federal	94	65	99	32	291
U.S. Total	231,927	85,114	136,487	11,293	464,821
Revenue (thousand dollars)					
Investor-Owned	1,121,011	983,229	548,116	74,604	2,726,960
Publicly Owned	4,488,624	2,307,362	3,513,148	300,631	10,609,765
Cooperative	11,133,164	2,722,436	2,365,624	400,965	16,622,189
Federal	7,995	4,999	6,436	1,328	20,758
U.S. Total	16,750,794	6,018,026	6,433,324	777,528	29,979,672
Average Revenue per Kilowatthour (cents)					
Investor-Owned	9.26	8.60	6.25	8.52	8.22
Publicly Owned	6.32	6.51	4.82	6.78	5.78
Cooperative	7.48	7.13	4.32	6.74	6.71
Federal	8.47	7.65	6.49	4.16	7.14
U.S. Average	7.22	7.07	4.71	6.89	6.45

[1] Includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data are final. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. .
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table C7. U.S. Electric Utilities Producing 25 Percent or Less of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership and Sector, 1996
(Million Kilowatthours)

Item	Residential	Commercial	Industrial	Other[1]	All Sectors
Sales (million kilowatthours)					
Investor-Owned	203	302	444	4	953
Publicly Owned	3,022	2,249	4,541	365	10,177
Cooperative	306	475	1,472	14	2,267
Federal	0	0	40,921	4,056	44,977
U.S. Total	3,531	3,026	47,378	4,440	58,374
Revenue (thousand dollars)					
Investor-Owned	12,277	14,063	18,940	471	45,751
Publicly Owned	136,560	99,177	120,015	17,669	373,421
Cooperative	23,922	31,987	45,194	1,382	102,485
Federal	0	0	1,019,270	90,955	1,110,225
U.S. Total	172,759	145,227	1,203,419	110,477	1,631,882
Average Revenue per Kilowatthour (cents)					
Investor-Owned	6.05	4.66	4.27	11.50	4.80
Publicly Owned	4.52	4.41	2.64	4.84	3.67
Cooperative	7.82	6.74	3.07	9.64	4.52
Federal	NA	NA	2.49	2.24	2.47
U.S. Average	4.89	4.80	2.54	2.49	2.80

[1] Includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data are final. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table C8. U.S. Electric Utilities Producing Greater Than 25 Percent of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership and Sector, 1996

(Million Kilowatthours)

Item	Residential	Commercial	Industrial	Other[1]	All Sectors
Sales (million kilowatthours)					
Investor-Owned	758,570	719,931	767,950	62,218	2,308,668
Publicly Owned	84,496	77,226	76,128	19,219	257,068
Cooperative	3,765	2,021	2,383	351	8,520
Federal	201	108	30	19	359
U.S. Total	**847,033**	**799,285**	**846,491**	**81,806**	**2,574,615**
Revenue (thousand dollars)					
Investor-Owned	67,211,107	56,267,281	36,052,392	4,492,126	164,022,906
Publicly Owned	6,002,531	5,211,167	3,568,490	1,332,651	16,114,839
Cooperative	352,700	177,834	126,383	27,316	684,233
Federal	11,265	7,103	1,419	1,255	21,042
U.S. Total	**73,577,603**	**61,663,385**	**39,748,684**	**5,853,348**	**180,843,020**
Average Revenue per Kilowatthour (cents)					
Investor-Owned	8.86	7.82	4.69	7.22	7.10
Publicly Owned	7.10	6.75	4.69	6.93	6.27
Cooperative	9.37	8.80	5.30	7.79	8.03
Federal	5.60	6.59	4.65	6.44	5.86
U.S. Average	**8.69**	**7.71**	**4.70**	**7.16**	**7.02**

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

Notes: •Data are final. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.

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

Table C9. U.S. Electric Utility Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Residential	924,019	955,417	935,939	994,781	1,008,482	1,042,501	1,082,491
Commercial	751,027	765,664	761,271	794,573	820,269	862,685	887,425
Industrial	945,522	946,583	972,714	977,164	1,007,981	1,012,693	1,030,356
Other[1]	91,988	94,339	93,442	94,944	97,830	95,407	97,539
U.S. Total	**2,712,555**	**2,762,003**	**2,763,365**	**2,861,462**	**2,934,563**	**3,013,287**	**3,097,810**
Revenue (thousand dollars)							
Residential	72,378,406	76,827,977	76,848,356	82,813,824	84,552,320	87,609,598	90,501,156
Commercial	55,116,676	57,655,250	58,342,561	61,521,269	63,395,592	66,364,681	67,826,638
Industrial	44,856,817	45,737,187	46,993,176	47,357,145	48,069,063	47,175,456	47,385,427
Other[1]	5,890,881	6,138,289	6,296,219	6,527,951	6,688,994	6,567,156	6,741,353
U.S. Total	**178,242,780**	**186,358,703**	**188,480,312**	**198,220,189**	**202,705,969**	**207,716,891**	**212,454,574**
Average Revenue per kilowatthour (cents)							
Residential	7.83	8.04	8.21	8.32	8.38	8.40	8.36
Commercial	7.34	7.53	7.66	7.74	7.73	7.69	7.64
Industrial	4.74	4.83	4.83	4.85	4.77	4.66	4.60
Other[1]	6.40	6.51	6.74	6.88	6.84	6.88	6.91
U.S. Average	**6.57**	**6.75**	**6.82**	**6.93**	**6.91**	**6.89**	**6.86**

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

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

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

Table C10. U.S. Electric Utilities Having No Generating Production and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Residential	187,716	193,779	192,093	205,570	210,572	215,653	231,927
Commercial	77,354	79,539	73,574	75,553	78,232	80,456	85,114
Industrial	98,635	100,959	110,902	117,758	122,122	129,174	136,487
Other[1]	11,031	11,051	10,266	10,029	10,882	10,688	11,293
U.S. Total	374,735	385,329	386,836	408,910	421,808	435,971	464,821
Revenue (thousand dollars)							
Residential	13,181,176	13,777,152	13,967,852	15,046,997	15,519,724	15,888,935	16,750,794
Commercial	5,294,112	5,529,572	5,286,070	5,443,527	5,640,398	5,760,613	6,018,026
Industrial	4,824,736	4,956,529	5,462,239	5,756,217	5,981,980	6,202,581	6,433,324
Other[1]	693,596	702,887	679,635	699,969	733,658	741,928	777,528
U.S. Total	23,993,620	24,966,140	25,395,796	26,946,710	27,875,760	28,594,057	29,979,672
Average Revenue per kilowatthour (cents)							
Residential	7.02	7.11	7.27	7.32	7.37	7.37	7.22
Commercial	6.84	6.95	7.18	7.20	7.21	7.16	7.07
Industrial	4.89	4.91	4.93	4.89	4.90	4.80	4.71
Other[1]	6.29	6.36	6.62	6.98	6.74	6.94	6.89
U.S. Average	6.40	6.48	6.57	6.59	6.61	6.56	6.45

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

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

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

Table C11. U.S. Electric Utilities Producing 25 Percent or Less of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Residential	2,916	3,100	2,517	2,390	1,334	2,781	3,531
Commercial	2,492	2,511	1,900	1,752	1,178	2,231	3,026
Industrial	24,487	24,609	23,151	21,183	24,235	49,616	47,378
Other[1]	6,933	5,465	5,316	5,903	6,019	4,648	4,440
U.S. Total	36,829	35,685	32,883	31,229	32,766	59,275	58,374
Revenue (thousand dollars)							
Residential	131,257	138,582	133,380	113,421	74,739	150,372	172,759
Commercial	103,853	110,203	102,047	86,249	51,009	112,908	145,227
Industrial	1,078,904	946,831	882,058	821,325	832,724	1,365,242	1,203,419
Other[1]	117,320	108,760	108,964	112,058	107,082	127,234	110,477
U.S. Total	1,431,334	1,304,376	1,226,449	1,133,053	1,065,554	1,755,756	1,631,882
Average Revenue per kilowatthour (cents)							
Residential	4.50	4.47	5.30	4.74	5.60	5.41	4.89
Commercial	4.17	4.39	5.37	4.92	4.33	5.06	4.80
Industrial	4.41	3.85	3.81	3.88	3.44	2.75	2.54
Other[1]	1.69	1.99	2.05	1.90	1.78	2.74	2.49
U.S. Average	3.89	3.66	3.73	3.63	3.25	2.96	2.80

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

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

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

Table C12. U.S. Electric Utilities Producing Greater Than 25 Percent of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Sector, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Residential	733,387	758,538	741,329	786,821	796,576	824,068	847,033
Commercial	671,181	683,613	685,796	717,268	740,860	779,998	799,285
Industrial	822,400	821,015	838,662	838,223	861,625	833,904	846,491
Other[1]	74,023	77,822	77,860	79,012	80,929	80,071	81,806
U.S. Total	**2,300,991**	**2,340,989**	**2,343,647**	**2,421,323**	**2,479,989**	**2,518,041**	**2,574,615**
Revenue (thousand dollars)							
Residential	59,065,973	62,912,243	62,747,124	67,653,406	68,957,857	71,570,291	73,577,603
Commercial	49,718,711	52,015,475	52,954,444	55,991,493	57,704,185	60,491,160	61,663,385
Industrial	38,953,177	39,833,827	40,648,879	40,779,603	41,254,359	39,607,633	39,748,684
Other[1]	5,079,965	5,326,642	5,507,620	5,715,924	5,848,254	5,697,994	5,853,348
U.S. Total	**152,817,826**	**160,088,187**	**161,858,067**	**170,140,426**	**173,764,655**	**177,367,078**	**180,843,020**
Average Revenue per kilowatthour (cents)							
Residential	8.05	8.29	8.46	8.60	8.66	8.68	8.69
Commercial	7.41	7.61	7.72	7.81	7.79	7.76	7.71
Industrial	4.74	4.85	4.85	4.87	4.79	4.75	4.70
Other[1]	6.86	6.84	7.07	7.23	7.23	7.12	7.16
U.S. Average	**6.64**	**6.84**	**6.91**	**7.03**	**7.01**	**7.04**	**7.02**

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

Table C13. U.S. Electric Utility Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Investor-Owned	2,071,069	2,110,528	2,112,271	2,186,889	2,237,683	2,292,442	2,342,808
Publicly Owned	385,853	393,448	395,386	406,998	421,642	431,618	450,928
Cooperative	200,946	205,083	206,939	221,206	228,535	239,726	258,448
Federal	54,687	52,944	48,768	46,370	46,703	49,501	45,626
U.S. Total	**2,712,555**	**2,762,003**	**2,763,365**	**2,861,462**	**2,934,563**	**3,013,287**	**3,097,810**
Revenue (thousand dollars)							
Investor-Owned	140,158,375	147,582,609	149,016,317	156,663,793	159,702,889	163,816,776	166,795,617
Publicly Owned	22,706,185	23,149,861	23,726,382	24,781,826	25,699,956	25,987,560	27,098,025
Cooperative	13,699,969	14,147,154	14,461,665	15,491,712	16,012,806	16,581,144	17,408,907
Federal	1,678,251	1,479,079	1,275,948	1,282,858	1,290,318	1,331,411	1,152,025
U.S. Total	**178,242,780**	**186,358,703**	**188,480,312**	**198,220,189**	**202,705,969**	**207,716,891**	**212,454,574**
Average Revenue per kilowatthour (cents)							
Investor-Owned	6.77	6.99	7.05	7.16	7.14	7.15	7.12
Publicly Owned	5.88	5.88	6.00	6.09	6.10	6.02	6.01
Cooperative	6.82	6.90	6.99	7.00	7.01	6.92	6.74
Federal	3.07	2.79	2.62	2.77	2.76	2.69	2.52
U.S. Average	**6.57**	**6.75**	**6.82**	**6.93**	**6.91**	**6.89**	**6.86**

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

Table C14. U.S. Electric Utilities Having No Generating Production and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Investor-Owned	32,368	31,993	32,688	33,944	32,813	32,901	33,187
Publicly Owned	154,270	157,743	156,856	163,889	171,042	173,857	183,683
Cooperative	187,844	195,292	197,019	210,804	217,724	228,933	247,660
Federal	253	301	273	273	229	279	291
U.S. Total	374,735	385,329	386,836	408,910	421,808	435,971	464,821
Revenue (thousand dollars)							
Investor-Owned	2,275,773	2,426,281	2,527,951	2,674,530	2,682,640	2,711,981	2,726,960
Publicly Owned	8,827,820	9,081,041	9,122,629	9,548,441	9,990,916	10,071,988	10,609,765
Cooperative	12,872,748	13,436,074	13,727,345	14,705,868	15,185,866	15,788,535	16,622,189
Federal	17,279	22,744	17,871	17,871	16,338	21,553	20,758
U.S. Total	23,993,620	24,966,140	25,395,796	26,946,710	27,875,760	28,594,057	29,979,672
Average Revenue per kilowatthour (cents)							
Investor-Owned	7.03	7.58	7.73	7.88	8.18	8.24	8.22
Publicly Owned	5.72	5.76	5.82	5.83	5.84	5.79	5.78
Cooperative	6.85	6.88	6.97	6.98	6.97	6.90	6.71
Federal	6.84	7.56	6.54	6.54	7.15	7.72	7.14
U.S. Average	6.40	6.48	6.57	6.59	6.61	6.56	6.45

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

Table C15. U.S. Electric Utilities Producing 25 Percent or Less of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Investor-Owned	125	122	132	123	122	924	953
Publicly Owned	8,495	9,086	6,939	6,711	3,869	7,233	10,177
Cooperative	2,311	2,257	2,240	302	2,305	2,227	2,267
Federal	25,899	24,220	23,572	24,093	26,470	48,890	44,977
U.S. Total	36,829	35,685	32,883	31,229	32,766	59,275	58,374
Revenue (thousand dollars)							
Investor-Owned	9,759	9,905	10,548	8,723	7,240	44,334	45,751
Publicly Owned	292,687	313,939	303,103	273,932	139,466	314,478	373,421
Cooperative	118,318	121,542	114,837	20,857	120,408	105,878	102,485
Federal	1,010,570	858,990	797,961	829,541	798,440	1,291,066	1,110,225
U.S. Total	1,431,334	1,304,376	1,226,449	1,133,053	1,065,554	1,755,756	1,631,882
Average Revenue per kilowatthour (cents)							
Investor-Owned	7.80	8.14	7.99	7.11	5.93	4.80	4.80
Publicly Owned	3.45	3.46	4.37	4.08	3.60	4.35	3.67
Cooperative	5.12	5.38	5.13	6.90	5.22	4.75	4.52
Federal	3.90	3.55	3.39	3.44	3.02	2.64	2.47
U.S. Average	3.89	3.66	3.73	3.63	3.25	2.96	2.80

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

Table C16. U.S. Electric Utilities Producing Greater Than 25 Percent of Their Own Generation and Their Sales to Ultimate Consumers, Associated Revenue, and Average Revenue per Kilowatthour by Class of Ownership, 1990 Through 1996

Item	1990	1991	1992	1993	1994	1995	1996
Sales (million kilowatthours)							
Investor-Owned	2,038,576	2,078,414	2,079,452	2,152,822	2,204,748	2,258,617	2,308,668
Publicly Owned	223,088	226,619	231,591	236,398	246,731	250,527	257,068
Cooperative	10,791	7,533	7,681	10,100	8,506	8,565	8,520
Federal	28,536	28,423	24,923	22,004	20,004	331	359
U.S. Total	**2,300,991**	**2,340,989**	**2,343,647**	**2,421,323**	**2,479,989**	**2,518,041**	**2,574,615**
Revenue (thousand dollars)							
Investor-Owned	137,872,843	145,146,423	146,477,818	153,980,540	157,013,009	161,060,461	164,022,906
Publicly Owned	13,585,678	13,754,881	14,300,650	14,959,453	15,569,574	15,601,094	16,114,839
Cooperative	708,903	589,538	619,483	764,987	706,532	686,731	684,233
Federal	650,402	597,345	460,116	435,446	475,540	18,792	21,042
U.S. Total	**152,817,826**	**160,088,187**	**161,858,067**	**170,140,426**	**173,764,655**	**177,367,078**	**180,843,020**
Average Revenue per kilowatthour (cents)							
Investor-Owned	6.76	6.98	7.04	7.15	7.12	7.13	7.10
Publicly Owned	6.09	6.07	6.17	6.33	6.31	6.23	6.27
Cooperative	6.57	7.83	8.07	7.57	8.31	8.02	8.03
Federal	2.28	2.10	1.85	1.98	2.38	5.67	5.86
U.S. Average	**6.64**	**6.84**	**6.91**	**7.03**	**7.01**	**7.04**	**7.02**

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

Table C17. Number of Ultimate Consumers by Class of Ownership, Census Division, and State, 1996

Census Division State	Investor-Owned	Publicly Owned	Cooperative	Federal	All Classes
New England	5,677,233	503,524	105,148	—	6,285,905
Connecticut	1,409,794	68,373	—	—	1,478,167
Maine	672,938	14,052	13,696	—	700,686
Massachusetts	2,388,091	357,736	—	—	2,745,827
New Hampshire	516,836	10,420	68,136	—	595,392
Rhode Island	446,996	4,025	—	—	451,021
Vermont	242,578	48,918	23,316	—	314,812
Middle Atlantic	15,762,101	289,198	214,923	—	16,266,222
New Jersey	3,373,195	53,546	10,408	—	3,437,149
New York	7,197,479	157,451	15,126	—	7,370,056
Pennsylvania	5,191,427	78,201	189,389	—	5,459,017
East North Central	16,918,962	1,316,330	1,395,610	—	19,630,902
Illinois	4,637,874	228,426	232,649	—	5,098,949
Indiana	2,020,028	243,155	416,364	—	2,679,547
Michigan	3,850,845	278,266	239,077	—	4,368,188
Ohio	4,378,303	339,797	308,761	—	5,026,861
Wisconsin	2,031,912	226,686	198,759	—	2,457,357
West North Central	5,232,520	1,982,076	1,753,644	33	8,968,273
Iowa	1,000,740	190,489	184,117	—	1,375,346
Kansas	863,966	227,604	187,060	—	1,278,630
Minnesota	1,271,094	304,244	565,609	3	2,140,950
Missouri	1,693,290	361,088	566,009	—	2,620,387
Nebraska	—	835,130	19,777	8	854,915
North Dakota	208,443	10,899	113,385	11	332,738
South Dakota	194,987	52,622	117,687	11	365,307
South Atlantic	16,848,980	2,336,896	3,758,607	5	22,944,488
Delaware	251,580	48,167	52,212	—	351,959
District of Columbia	218,979	—	—	—	218,979
Florida	5,702,522	1,050,198	719,942	—	7,472,662
Georgia	1,851,335	311,829	1,255,884	—	3,419,048
Maryland	1,925,950	30,571	144,888	—	2,101,409
North Carolina	2,480,121	485,622	728,175	5	3,693,923
South Carolina	1,096,017	257,674	513,455	—	1,867,146
Virginia	2,418,406	149,304	335,820	—	2,903,530
West Virginia	904,070	3,531	8,231	—	915,832
East South Central	2,905,163	2,555,664	2,334,213	93	7,795,133
Alabama	1,240,065	428,989	431,392	22	2,100,468
Kentucky	1,061,951	193,582	624,779	22	1,880,334
Mississippi	560,843	126,769	585,306	6	1,272,924
Tennessee	42,304	1,806,324	692,736	43	2,541,407
West South Central	9,237,264	1,764,041	2,295,562	—	13,296,867
Arkansas	770,999	146,011	357,012	—	1,274,022
Louisiana	1,495,585	148,824	317,989	—	1,962,398
Oklahoma	1,111,908	173,675	382,296	—	1,667,879
Texas	5,858,772	1,295,531	1,238,265	—	8,392,568
Mountain	5,074,066	1,321,149	948,254	30,930	7,374,399
Arizona	1,087,155	696,463	119,372	16,016	1,919,006
Colorado	1,195,164	316,383	374,347	7	1,885,901
Idaho	473,594	36,829	57,757	—	568,180
Montana	332,061	877	112,228	14,889	460,055
Nevada	705,219	18,481	24,136	2	747,838
New Mexico	547,430	69,521	162,478	5	779,434
Utah	567,268	158,321	27,054	7	752,650
Wyoming	166,175	24,274	70,882	4	261,335
Pacific	12,208,553	4,268,470	295,002	85	16,772,110
California	9,901,823	2,756,678	12,969	61	12,671,531
Oregon	1,140,092	229,517	164,540	9	1,534,158
Washington	1,166,638	1,282,275	117,493	15	2,566,421
Pacific Noncontiguous	434,206	60,885	172,701	2	667,794
Alaska	22,515	60,885	172,701	2	256,103
Hawaii	411,691	—	—	—	411,691
U.S. Total	90,299,048	16,398,233	13,273,664	31,148	120,002,093

Notes: •Data are final. •The number of ultimate consumers is an average of the number of consumers at the close of each month.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table C18. Number of Ultimate Consumers for U.S. Electric Utilities Having No Generating Production by Class of Ownership, Census Division, and State, 1996

Census Division State	Investor-Owned	Publicly Owned	Cooperative	Federal	All Classes
New England	**1,277,385**	**238,884**	**28,316**	**—**	**1,544,585**
Connecticut	0	19,400	—	—	19,400
Maine	0	6,679	13,696	—	20,375
Massachusetts	1,134,328	187,555	—	—	1,321,883
New Hampshire	109,781	9,372	—	—	119,153
Rhode Island	32,478	4,025	—	—	36,503
Vermont	798	11,853	14,620	—	27,271
Middle Atlantic	**82,547**	**211,801**	**214,923**	**—**	**509,271**
New Jersey	66,031	35,853	10,408	—	112,292
New York	894	107,978	15,126	—	123,998
Pennsylvania	15,622	67,970	189,389	—	272,981
East North Central	**37,452**	**677,367**	**1,360,634**	**—**	**2,075,453**
Illinois	5,664	104,249	232,649	—	342,562
Indiana	378	175,633	416,364	—	592,375
Michigan	15,074	43,982	212,535	—	271,591
Ohio	—	170,898	308,761	—	479,659
Wisconsin	16,336	182,605	190,325	—	389,266
West North Central	**833**	**654,563**	**1,714,492**	**—**	**2,369,888**
Iowa	833	54,777	184,117	—	239,727
Kansas	—	38,543	151,999	—	190,542
Minnesota	—	152,032	561,521	—	713,553
Missouri	—	108,538	566,007	—	674,545
Nebraska	—	238,192	19,777	—	257,969
North Dakota	—	10,899	113,384	—	124,283
South Dakota	—	51,582	117,687	—	169,269
South Atlantic	**72,442**	**927,561**	**3,661,232**	**—**	**4,661,235**
Delaware	—	25,104	52,212	—	77,316
District of Columbia	—	—	—	—	—
Florida	23,120	68,989	691,083	—	783,192
Georgia	—	267,237	1,255,884	—	1,523,121
Maryland	—	20,697	144,523	—	165,220
North Carolina	—	384,808	700,704	—	1,085,512
South Carolina	—	103,441	513,455	—	616,896
Virginia	—	53,754	295,523	—	349,277
West Virginia	49,322	3,531	7,848	—	60,701
East South Central	**160,787**	**2,491,272**	**2,333,365**	**—**	**4,985,424**
Alabama	—	428,989	431,392	—	860,381
Kentucky	118,557	153,503	624,779	—	896,839
Mississippi	—	102,456	585,306	—	687,762
Tennessee	42,230	1,806,324	691,888	—	2,540,442
West South Central	**41,305**	**419,706**	**2,274,499**	**—**	**2,735,510**
Arkansas	—	38,357	357,012	—	395,369
Louisiana	—	41,633	317,989	—	359,622
Oklahoma	—	132,148	382,296	—	514,444
Texas	41,305	207,568	1,217,202	—	1,466,075
Mountain	**3,525**	**297,903**	**882,186**	**12,409**	**1,196,023**
Arizona	3,171	68,286	118,990	12,409	202,856
Colorado	—	89,321	371,927	—	461,248
Idaho	—	11,535	38,477	—	50,012
Montana	—	877	108,006	—	108,883
Nevada	354	18,481	19,501	—	38,336
New Mexico	—	23,415	162,478	—	185,893
Utah	—	61,714	8,638	—	70,352
Wyoming	—	24,274	54,169	—	78,443
Pacific	**29,148**	**659,353**	**294,987**	**—**	**983,488**
California	20,458	189,726	12,969	—	223,153
Oregon	—	122,798	164,540	—	287,338
Washington	8,690	346,829	117,478	—	472,997
Pacific Noncontiguous	**108**	**—**	**1,116**	**—**	**1,224**
Alaska	108	—	1,116	—	1,224
Hawaii	—	—	—	—	—
U.S. Total	**1,705,532**	**6,578,410**	**12,765,750**	**12,409**	**21,062,101**

Notes: •Data are final. •The number of ultimate consumers is an average of the number of consumers at the close of each month.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table C19. Number of Ultimate Consumers for U.S. Electric Utilities Producing 25 Percent or Less of Their Own Generation by Class of Ownership, Census Division, and State, 1996

Census Division State	Investor-Owned	Publicly Owned	Cooperative	Federal	All Classes
New England	37	0	—	—	37
Connecticut	0	0	—	—	0
Maine	0	—	—	—	0
Massachusetts	34	0	—	—	34
New Hampshire	1	—	—	—	1
Rhode Island	—	—	—	—	—
Vermont	2	0	—	—	2
Middle Atlantic	1	1,965	0	—	1,966
New Jersey	0	—	—	—	0
New York	1	1,965	—	—	1,966
Pennsylvania	0	—	0	—	0
East North Central	0	10,688	15,700	0	26,388
Illinois	0	9,552	0	—	9,552
Indiana	—	0	0	—	0
Michigan	—	1,136	15,700	0	16,836
Ohio	0	—	0	—	0
Wisconsin	0	0	0	—	0
West North Central	—	136,058	35,063	33	171,154
Iowa	—	846	0	—	846
Kansas	—	—	35,061	—	35,061
Minnesota	—	11,386	0	3	11,389
Missouri	—	9,999	1	—	10,000
Nebraska	—	112,787	—	8	112,795
North Dakota	—	0	1	11	12
South Dakota	—	1,040	—	11	1,051
South Atlantic	0	0	0	5	5
Delaware	—	—	—	—	—
District of Columbia	—	—	—	—	—
Florida	—	0	0	—	0
Georgia	—	0	0	0	0
Maryland	—	—	—	—	—
North Carolina	0	0	0	5	5
South Carolina	0	0	0	—	0
Virginia	—	0	0	—	0
West Virginia	—	—	—	—	—
East South Central	0	12,628	0	93	12,721
Alabama	0	—	0	22	22
Kentucky	—	12,628	0	22	12,650
Mississippi	—	—	0	6	6
Tennessee	—	—	—	43	43
West South Central	0	2,070	0	0	2,070
Arkansas	—	—	0	—	0
Louisiana	0	1,983	0	—	1,983
Oklahoma	—	66	0	0	66
Texas	—	21	0	—	21
Mountain	33,962	3,615	0	52	37,629
Arizona	—	—	0	19	19
Colorado	0	3,615	0	7	3,622
Idaho	—	—	—	—	—
Montana	—	—	—	8	8
Nevada	—	—	—	2	2
New Mexico	—	—	0	5	5
Utah	0	0	0	7	7
Wyoming	33,962	0	—	4	33,966
Pacific	0	87,227	0	85	87,312
California	—	2	0	61	63
Oregon	0	—	0	9	9
Washington	—	87,225	—	15	87,240
Pacific Noncontiguous	—	0	8	2	10
Alaska	—	0	8	2	10
Hawaii	—	—	—	—	—
U.S. Total	34,000	254,251	50,771	270	339,292

Notes: •Data are final. •The number of ultimate consumers is an average of the number of consumers at the close of each month.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table C20. Number of Ultimate Consumers for U.S. Electric Utilities Producing Greater than 25 Percent of Their Own Generation by Class of Ownership, Census Division, and State, 1996

Census Division State	Investor-Owned	Publicly Owned	Cooperative	Federal	All Classes
New England	**4,399,811**	**264,640**	**76,832**	**—**	**4,741,283**
Connecticut	1,409,794	48,973	—	—	1,458,767
Maine	672,938	7,373	—	—	680,311
Massachusetts	1,253,729	170,181	—	—	1,423,910
New Hampshire	407,054	1,048	68,136	—	476,238
Rhode Island	414,518	—	—	—	414,518
Vermont	241,778	37,065	8,696	—	287,539
Middle Atlantic	**15,679,553**	**75,432**	**—**	**—**	**15,754,985**
New Jersey	3,307,164	17,693	—	—	3,324,857
New York	7,196,584	47,508	—	—	7,244,092
Pennsylvania	5,175,805	10,231	—	—	5,186,036
East North Central	**16,881,510**	**628,275**	**19,276**	**—**	**17,529,061**
Illinois	4,632,210	114,625	—	—	4,746,835
Indiana	2,019,650	67,522	—	—	2,087,172
Michigan	3,835,771	233,148	10,842	—	4,079,761
Ohio	4,378,303	168,899	—	—	4,547,202
Wisconsin	2,015,576	44,081	8,434	—	2,068,091
West North Central	**5,231,687**	**1,191,455**	**4,089**	**—**	**6,427,231**
Iowa	999,907	134,866	—	—	1,134,773
Kansas	863,966	189,061	—	—	1,053,027
Minnesota	1,271,094	140,826	4,088	—	1,416,008
Missouri	1,693,290	242,551	1	—	1,935,842
Nebraska	—	484,151	—	—	484,151
North Dakota	208,443	—	—	—	208,443
South Dakota	194,987	—	—	—	194,987
South Atlantic	**16,776,538**	**1,409,335**	**97,375**	**—**	**18,283,248**
Delaware	251,580	23,063	—	—	274,643
District of Columbia	218,979	—	—	—	218,979
Florida	5,679,402	981,209	28,859	—	6,689,470
Georgia	1,851,335	44,592	—	—	1,895,927
Maryland	1,925,950	9,874	365	—	1,936,189
North Carolina	2,480,121	100,814	27,471	—	2,608,406
South Carolina	1,096,017	154,233	—	—	1,250,250
Virginia	2,418,406	95,550	40,297	—	2,554,253
West Virginia	854,748	—	383	—	855,131
East South Central	**2,744,376**	**51,764**	**848**	**—**	**2,796,988**
Alabama	1,240,065	—	—	—	1,240,065
Kentucky	943,394	27,451	—	—	970,845
Mississippi	560,843	24,313	—	—	585,156
Tennessee	74	—	848	—	922
West South Central	**9,195,959**	**1,342,265**	**21,063**	**—**	**10,559,287**
Arkansas	770,999	107,654	—	—	878,653
Louisiana	1,495,585	105,208	—	—	1,600,793
Oklahoma	1,111,908	41,461	—	—	1,153,369
Texas	5,817,467	1,087,942	21,063	—	6,926,472
Mountain	**5,036,579**	**1,019,631**	**66,068**	**18,469**	**6,140,747**
Arizona	1,083,984	628,177	382	3,588	1,716,131
Colorado	1,195,164	223,447	2,420	—	1,421,031
Idaho	473,594	25,294	19,280	—	518,168
Montana	332,061	—	4,222	14,881	351,164
Nevada	704,865	—	4,635	—	709,500
New Mexico	547,430	46,106	—	—	593,536
Utah	567,268	96,607	18,416	—	682,291
Wyoming	132,213	—	16,713	—	148,926
Pacific	**12,179,405**	**3,521,890**	**15**	**—**	**15,701,310**
California	9,881,365	2,566,950	—	—	12,448,315
Oregon	1,140,092	106,719	—	—	1,246,811
Washington	1,157,948	848,221	15	—	2,006,184
Pacific Noncontiguous	**434,098**	**60,885**	**171,577**	**—**	**666,560**
Alaska	22,407	60,885	171,577	—	254,869
Hawaii	411,691	—	—	—	411,691
U.S. Total	**88,559,516**	**9,565,572**	**457,143**	**18,469**	**98,600,700**

Notes: •Data are final. •The number of ultimate consumers is an average of the number of consumers at the close of each month.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Appendix D

Fundamentals of Electric Power Transmission and Integrating Nonutility Generators

Appendix D

Fundamentals of Electric Power Transmission and Integrating Nonutility Generators

Fundamentals of the Electric Power Transmission System[233]

The electric power system in the United States contains three interrelated elements: the generating facilities that produce the power; the transmission network that conducts the flow of power from the points of generation to the points of distribution; and the distribution system that delivers the electric power to the consumers. The transmission network is the integrating medium of the power supply system providing the electrical connections between the many geographically separated parts of the electric power generating and distribution systems.

The electric transmission network is unlike any other mode of transportation. The flow of electricity is virtually instantaneous, changing magnitude and direction as conditions on the power system dictate.[234] Electricity distributes itself along paths of least resistance that are determined by a complex electrical relationship involving the relative size, location, and distribution of generation resources, transmission line facilities, and centers of demand. All transmission paths share the power transfer, and the degree of sharing is determined by the relationship of the network components. The system consists of transmission and distribution lines, substations with voltage transformers, circuit breakers, and other equipment required to transmit power safely from generation sources to ultimate customers. Transmission voltage levels have increased with improvements in technology and in keeping with the growing demand for electricity.

The transmission system performs several essential functions simultaneously: (1) it supplies the physical means for delivering electricity from the generating sources to the load centers; (2) it integrates generating sources and load centers into a flexible and resilient whole; and (3) it interconnects the physical facilities with those of neighboring systems. Although transmission lines are often added to the network initially to meet a single specific requirement, once added they become an integrated part of the transmission network and their operation becomes interdependent with all the other elements of the network. Operating the system effectively requires significant planning and operational coordination of the generators and transmission facilities to: (1) achieve efficient use of all system facilities, (2) prevent overloading and failure, and (3) maintain adequate reserve transmission and generation capacity to ensure system reliability.

The Need for Coordination of System Operation

The current electrical system has developed in response to the regulations and economics of the electrical utility and nonutility sectors of the electric power industry, as well as to the changing technical factors that influence the generation, transmission, and distribution of electricity. Since the different electrical systems operate as a unified power grid (there are three in the contiguous United States) and the effects of power flows are not confined to contractual paths or apparent direct paths, handling the ever changing flow of electricity is a critical activity for system operators of the power grids. Large power transfers, for example, can change transmission line loadings hundreds of miles from the direct electrical path connecting the source and destination. Actions by individual utilities or nonutility generators (NUGs) can affect the operation of all the others on the system.

[233] Note that the description in this section describes a state prior to the issuance of Federal Energy Regulatory Commission Order 888 in April 1996.

[234] The frequency of electric power supply in the United States is almost entirely 60 hertz (formerly cycles per second). The frequency of a system depends entirely upon the speed at which the supply generator is rotated by its prime mover. James Robert Eaton, *Electric Power Transmission Systems.* (Englewood Cliffs, New Jersey: Prentice-Hall, Inc., 1972), pp. 2-3.

Control and Operation of Electric Systems

As electrical energy itself cannot be stored, power must be instantaneously available to end users at any time, in any amount at the proper voltage. As a result, severe demands are imposed on electrical equipment and the transmission network when meeting changing loads. Monitoring the flow of scheduled electricity, handling customer requirements, and coordinating trade among utilities are among the responsibilities of the dispatch center. A dispatch center can be operated independently of other electrical systems by a single utility; it can link two or more interconnected utilities, or even unify several power systems with combined load requirements and maintenance programs.

The operators of dispatch centers continually monitor load patterns to ensure that adequate electricity is available at all times. For most dispatch centers, it is the daily responsibility to (1) record the flow of electricity at the customer load centers and the entering and exiting amounts on its transmission lines, (2) watch the transmission connecting points for each interconnected electrical system, and (3) monitor the power flow from each generation plant. The dispatch center determines the power available from its system, balances the unit-generation marginal costs with buy-or-sell opportunities with other utilities, coordinates the bulk power transactions, examines what plants must be dispatched to avoid technical system problems or undue economic costs, and accounts for system power losses. It also projects demand requirements in order to determine how much generating capacity will be needed and when. These projections may be done hourly, daily, weekly, or at longer intervals.

One electrical operating entity (power pool, electric utility, State authority, and/or Federal utility) within a group of interconnected electrical systems takes responsibility for maintaining system frequency for that electrical geographic area, monitors the load, and ensures generation availability to meet load requirements. Some control centers within these control areas are highly computerized, automatically loading the generating facilities as needed and maintaining the system at the correct operating frequency. This is important because deviations in the scheduled power flows or from the standard system frequency can automatically cause compensating changes in the output at the generating plants. These deviations can mean there has been a loss or gain of a customer load, a plant or line has suffered a forced outage, or some plant or line has been returned to the system. Any of these changes can require some review or action by these control centers.

Stabilizing system frequency is made easier by coordination with other electric systems and by drawing from a larger base of on-line capability. Load changes are absorbed by all the electrical systems, and many of the increasing and decreasing load changes cancel out or offset each other, so that the effect on the entire interconnected electrical system is less than it would be on an isolated electric utility. Also, this integrated system frees each generating unit from the necessity to make continual large changes in production levels.

Integrating Nonutility Generators with the Bulk Electric System

Nonutility generation sources continue to be a growing portion of the U.S. electrical generation capacity. This role of NUGs reflects the changing structure of the electric supply system.

Integrating Nonutility Generators

NUGs present a challenge to the operators of the power grids because of their increasing numbers and growing contribution to wholesale generation. Matching customer load and generation for daily operations and future planning activities is becoming increasingly complex with the growing NUG role and increasing use of the transmission system. Electrical reliability concerns and the proper integration of NUGs into the supply system have become important issues.

The proper integration of NUGs into the electrical operations of interconnection and dispatching generation can be regarded as engineering problems for which technical solutions are available. However, there are institutional issues associated with the responsibility for serving customers and control of the electrical system. The increasing role of NUGs has altered the traditional view of participants in the electrical supply.

Utilities have three basic concerns involving the integration of NUGs with the bulk power system, relating primarily to the relationships of the NUGs, utilities, and customers:

- Utilities, with the principal responsibility to operate the system, do not always have full operating control over the NUGs.

- The forces that drive NUG development and operation do not necessarily coincide with the obligations of the utilities to serve customer demands.

- The fulfillment of NUG development plans to support the future generation requirements of the system are not controlled by the utilities, which are still obligated in most States to provide sufficient capacity.

The investor-owned utility obligation to serve is part of what was once called the "regulatory compact," which tied the utility exclusivity to a service territory franchise and requires that the rate of return and prices be set by a regulatory body. However, the obligation of NUGs to provide power tends to be contractual. This contractual obligation (power sales contract) must be satisfied to provide an adequate return on investment and to service debt.

The perspectives of some utility industry organizations and NUG participants on these obligations may differ. Some of these differences can be attributed to positions of the organizations in the market, with respect to their cost structures and existing capacity. Some utilities welcome the opportunity for potential cost savings and diversity of supply options offered by NUGs, others are more concerned about operations and overall system reliability.

In response to such concerns, the North American Electric Reliability Council (NERC), which the utility industry charged to oversee the reliability of the bulk electric supply, has established guidelines on the minimum operating considerations that all utility and nonutility generators must follow to ensure the continued reliability of the system.[235]

Impact of Nonutility Generation on the Supply System

The electric utility industry and nonutility industry have worked together to safely and reliably interconnect NUGs. Many utilities are increasingly relying on NUG power as an important source of power. Several factors which utilities may not control can influence the operation of the overall system. The overall level of increase in NUG capacity is just one element. The size of individual facilities has a direct bearing on the potential system impacts; small facilities are less likely to have the same impacts as large ones. At the same time, the locations of individual projects, even small ones, can be critical. Where a facility is sited can affect transmission line loadings and substation equipment operation. Similarly, the timing of power production from a NUG facility can affect the balance of power flows on the system. Moreover, the availability and reliability of NUG power can influence the operation of the system and the requirements for reserve capacity.

The electrical supply system is operated within closely watched tolerances and can require complex and real-time balancing of generation and transmission facilities with fluctuating demand. The substantial interrelationships of all the system components—utility and nonutility—suggest that generation capacity that falls outside the direct control of system operators increases their operational and planning challenges, and may affect system reliability. The extent to which operation, size, location, timing, availability and reliability of NUG power production can be coordinated with system operators will determine the impacts of NUG integration on the bulk electricity supply system.

Technically, all of these factors exert both positive and negative influences on the electrical system, depending on site-specific conditions and timing of actions. For example, a NUG facility could be located specifically to help a utility avoid a transmission or distribution bottleneck. Proper integration of NUGs into the daily operational control and management of the electrical power grid is critical for capturing the benefits and minimizing the disadvantages for all entities connected to the grid.

[235] North American Electric Reliability Council, *Integrating Nonutility Generators* (Princeton, New Jersey, January 1992). The specific guidelines now address both planning and operating considerations, and apply to all utility and nonutility sources. The guidelines address a range of needs, from specific design issues, to information needs, and data exchange requirements. The guidelines also cover how the generation sources would be brought on- and off-line during routine and emergency conditions.

Appendix E

Treatment of Stranded Costs in States as of April 30, 1998

- Arizona
- California
- Connecticut
- Illinois
- Maine
- Maryland
- Massachusetts
- Michigan
- Montana
- Nevada
- New Hampshire
- New Jersey
- New York
- Oklahoma
- Pennsylvania
- Rhode Island
- Vermont
- Virginia

Appendix E

Treatment of Stranded Costs in States as of April 30, 1998

Arizona

On December 26, 1996, the Arizona Corporation Commission (ACC or the Commission) approved "Electric Competition Rules" (or Rules) setting forth a framework for electricity restructuring in the State and for introducing a phased-in transition to a competitive retail power market beginning in 1999. These Rules also include a wide spectrum of issues, including the treatment of stranded costs. In connection therewith, affected utilities in the State will make available at least 20 percent of their 1995 system retail peak demand to all customer classes in 1999, 50 percent in 2001, and 100 percent by 2003.[236]

A special working group was created to develop recommendations for the analysis and recovery of stranded costs.[237] This Group, the Stranded Cost Working Group (the Group), submitted its final report and recommendations in September 1997.[238] The Group's recommendations to the Commission are based on a consensus on various stranded cost issues. However, the Group acknowledges that it achieved consensus on some issues but that many issues remain unresolved.

Consensus was reached on the following issues:

- Components of stranded cost should include generation assets, purchased power agreements, fuel contracts, regulatory assets, employment transition costs, and environmental mandates.

- All customers should pay stranded costs, including those who do not take competitive power.[239] Self-generation, demand-side management activities, or other modes of demand reduction by customers do not warrant stranded cost recovery. Customers should have the option of paying one lump sum in lieu of payments over a period of time.

- The Group noted that the *Electric Competition Rules* were silent on the subject of the specific recovery mechanism to be implemented. Mechanisms examined include a variable charge based on electricity usage, a fixed fee (including but not limited to an exit fee) independent of usage, and an access fee levied on competitive suppliers. In addition, there could be a nonbypassable usage surcharge with the option of an exit fee, or a fixed fee to be determined on a utility-by-utility basis.

[236] Arizona Corporation Commission, *In the Matter of the Competition in the Provision of Electric Services Throughout the State of Arizona, Decision and Amended Rules on Electric Competition, Opinion and Order*, Docket No. U-0000-94-165, Decision No. 59943 (December 26, 1996).

[237] As defined in Title 14, Section R14-2-1601 of the ACC Competition Rules (December 1996), "stranded cost" means the variable net difference between:

"a. The value of all prudent jurisdictional assets and obligations necessary to furnish electricity (such as generating plants, purchased power contracts, fuel contracts and regulatory assets), acquired or entered into prior to the adoption of this Article, under traditional regulation of Affected Utilities; and

b. The market value of those assets and obligations directly attributable to the introduction of competition under this Article."

[238] Arizona Corporation Commission, *Stranded Cost Working Group Report to the Commission* (September 30, 1997).

[239] These options were provided by the *Recovery Mechanism Subcommittee* in its report submitted to the Group on June 30, 1997. This Group, however, recommended that those remaining in the system and those opting out should be treated differently. In addition, the stranded cost charge should reflect energy and demand charges of the underlying stranded cost.

- The Commission should consider some variant of a rate cap as a part of the stranded cost recovery program. In addition, the recovery mechanism should correspond to the prevailing regulatory rate allocation scheme among existing customer classes.

The Group submitted the following for the Commission's further consideration:

- Clarification is needed on whether nuclear fuel costs should be included in stranded costs.

- Prudent and reasonable mitigation efforts should be handled on a case-by-case basis. The mitigation costs should be eligible for treatment as stranded costs.

- The "Net Revenues Lost" approach should be adopted for computing stranded costs. Under this approach, future revenue streams assuming continuation of regulations are compared with revenue streams likely to be generated in a competitive market.

- The issue of price determination under competition (including projections) should be carefully studied.

- Estimates of stranded costs should be periodically trued up.

- Stranded cost recovery should be limited to 10 years.

- The Commission should ensure that recoveries made to pay for stranded costs are in fact used to reduce existing liabilities.

- Parties advocating a price cap or the sharing of stranded costs by the equity holders should be asked to provide specific details.

The Group recommended that the Commission clarify rules so that the identification, quantification, and recovery of stranded costs minimizes tax write-offs. In addition, the Commission was requested to analyze issues related to tax-exempt bonds.

While the Commission and the Group have been grappling with stranded cost issues (besides a host of other issues), the two largest investor-owned utilities in Arizona—Arizona Power Service and Tucson Electric Power—filed lawsuits addressing the rulemaking completed by the ACC in December 1996. The Arizona Supreme Court upheld the restructuring rulemaking in a decision issued April 23, 1998.[240]

Subsequent evaluations made by the ACC staff acknowledge difficulties in recommending a single methodology that can be used by all utilities in the State to determine their stranded costs. Accordingly, the staff recommended three approaches: net revenues lost methodology, divestiture auction, and financial integrity methodology.[241]

Under the net revenues lost option, generation revenues with competition are compared to generation revenues without competition. The difference is treated as potential stranded costs to be allocated among ratepayers. The divestiture auction methodology determines stranded costs through auction of generating assets. The financial integrity methodology calls for financial viability of each utility to be maintained for 10 years following competition. These recommendations await the ACC's decision, after which the utilities have 30 days to file stranded cost plans.

California

In the wake of the Energy Policy Act of 1992, the California Public Utilities Commission (CPUC or the Commission) was one of the first State commissions to initiate electric industry restructuring studies, in early 1993.[242] In April 1994, the CPUC initiated a comprehensive rulemaking and investigation into restructuring and reforming regulation for California's electric service industry.[243]

[240] Arizona Commission Corporation Press Release, "Supreme Court Rejects Attack on Corporation Commission Authority to Restructure the Electric Industry" (April 23, 1998).

[241] Recommendations by ACC Hearing Officer entered on May 6, 1998 under Docket No. RE-00000C-94-0165.

[242] California Public Utilities Commission, Division of Strategic Planning, *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future* (February 1993). This publication—known as the Yellow Book—provides an in-depth discussion of the industry and the need for regulatory reform.

[243] California Public Utilities Commission, *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation*, Docket No. R.94-04-031, and *Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation*, Docket No. I.94-04-032 (April 20, 1994).

In the policy decision development proceedings that followed, the CPUC recognized "that in the transition to the new industry structure, certain utility generation-related capital and operating costs would prove to be uneconomic and would not be recovered through market revenues."[244] These uneconomic or stranded assets, to be called "transition costs," included generation assets, nuclear power plant settlements, power purchase agreements, qualifying facilities contracts, and the reasonable capital costs of early retirement or retraining programs for employees.[245] The estimated net book value of the utilities' non-nuclear costs eligible for transition recovery was established by the Commission at approximately $4 billion.[246]

The Commission proposed that transition costs are to be recovered through a nonbypassable competition transition charge (CTC) to be applied to all customers regardless of whether they get bundled service from their utility.[247] Customers opting to use power from alternative suppliers will still be required to pay the CTC to the distribution utility.

The CTC will be based on a customer's power consumption and will appear as a separate charge on the electricity bill. It will be calculated as the difference between the pool energy price, the unbundled cost of distribution and transmission, and the cost of ancillary services and energy tariffs filed by the utilities.[248] CTC recovery will start with the commencement of direct access and is projected to continue through a 4-year period until December 31, 2001.

In addition to using the CTC to collect stranded costs, the CPUC approved issuance by the investor-owned utilities of rate reduction bonds (RRBs) to securitize a total of $7.3 billion of stranded costs.[249] Issuance of these bonds will permit a rate reduction of 10 percent beginning March 31, 1998, and continuing until March 31, 2002. Rate reductions of 20 percent are anticipated after 2002.[250] The Utility Reform Network, a consumer group, has asked the California Supreme Court to overturn the CPUC's approval of the rate reduction bonds.[251]

Utilities in the State were directed to establish their level of transition costs as of the start of direct access by filing applications to the CPUC by September 2, 1996.[252] In determining transition cost levels for each utility, economic assets are to be netted out against uneconomic assets.[253] The CPUC will hold annual proceedings to determine the amount of recoverable stranded costs. With the objective to minimize transition costs, the Commission plans to rely on market forces (to the extent possible) in its determination.[254] The CTC level to be recovered will depend on the market-clearing price in

[244] California Public Utilities Commission, Decision 97-06-060 (June 11, 1997).

[245] Uneconomic cost (or asset) was defined as the difference between the book value and the market value of an asset at the time of divestiture, spinoff, or appraisal. Ongoing uneconomic costs were those that were greater than the market clearing price at the power exchange.

[246] An independent audit was performed to estimate the level of non-nuclear stranded costs for each of the three investor-owned utilities. For Pacific Gas and Electric Company (PG&E), $2.8 billion, Southern California Edison Company (SCE), $1.1 billion, and San Diego Gas & Electric Company (SDG&E), $130 million. California Public Utilities Commission News Release (November 19, 1997).

[247] California Public Utilities Commission, *Preferred Policy Decision*, D.96-01-009 (January 10, 1996), p. 109.

[248] A market rate forecast of 2.4 cents per kilowatthour will be used to estimate transition costs for 1998. This rate may be useful to the utilities in developing rate reduction bond proposals.

[249] Bond issue authority was issued as follows: PG&E, $3.5 billion, SCE, $3.0 billion, SDG&E, $0.8 billion (CPUC Press Release, September 3, 1997, CPUC 123). PG&E's stranded cost estimates are between $8 and $14 billion (CPUC Decision 97-09-055). SDG&E and Edison estimate their stranded costs as at least "four times greater than the aggregate principal amount of the proposed issuance of RRBs," according to CPUC Decisions 97-09-056 and 97-09-057. In each case, "a bond sizing model would be applied. . .to determine the precise amount of rate reduction bonds needed to finance a 10-percent rate reduction for residential and small commercial consumers" (CPUC Decision 97-09-054).

[250] The RRBs are to be repaid by an additional charge of less than 2 cents per kilowatthour on residential and small business customers. Despite this charge, estimated net savings of up to $970 million are projected over approximately a 10-year period. California Public Utilities Commission Press Release, CPUC-096 (September 3, 1997).

[251] "Group Petitions California High Court to Disallow Rate Reduction Bonds," *Electric Utility Week* (October 27, 1997), pp.14-15.

[252] January 1, 1998, was the original date for electric restructuring to begin in California. Note that the filing date for transition cost estimations was changed to August 31, 1997.

[253] Valuation of generation-related assets must be completed by the year-end 2001.

[254] The Commission viewed this approach to be superior to other ways of calculating transition costs. The market-based approach, which derives its value from observation of the collective actions of buyers and sellers, eliminates the need for forecasting based on assumptions that can be contested. Note that estimates of overall transition costs in California range from a *negative* $8 billion to $32 billion. California Public Utilities Commission, Decision 96-01-009 (January 10, 1996).

the State-wide power exchange on the date direct access begins.[255]

Divestiture is an important first step in the market-based valuation of assets. Once the assets are divested, the CPUC has a figure upon which to track appropriate stranded cost recovery. Two of the State's utilities—Pacific Gas and Electric and Southern California Edison—were required to divest at least 50 percent of their generating assets.[256] The Commission authorized the utilities to go ahead with proposed sales.[257] Although not required, San Diego Gas and Electric has announced plans to auction off 2,778 megawatts of capacity and contracts and will ask the CPUC for approval.

For eligible costs that are not divested, their value is "compared to the Power Exchange market clearing price on an ongoing basis in order to determine the uneconomic portion."[258] Regardless of whether an asset is market valued through divestiture or comparison, the utilities will track CTC revenue and offset stranded costs through transition accounts. The main account will repay generation-related stranded costs. Revenues above planned levels will be used to pay stranded costs, and as a result stranded cost recovery could take less than the originally planned 4 years. Pacific Gas and Electric, Edison, and San Diego Gas and Electric have been directed to "establish subaccounts as placeholders in their transition cost balancing accounts to track recorded employee related and restructuring implementation costs."[259] According to the CPUC, one purpose of these accounts "is to track the going forward costs and market revenues for particular assets and to verify that market revenues which are greater than costs are credited appropriately to the transition cost balancing account."[260] Annually, a transition cost proceeding will develop necessary adjustments. Additionally, since all the generation stranded costs are to be recovered by December 31, 2001, they will be deferred until after that date.

For some of the initiatives proposed by the Commission, legislative authority was required for implementation purposes. Assembly Bill 1890, signed into law on September 23, 1996, endorsed the Commission's basic decisions and enlarged upon others. AB 1890 provides for freezing electric rates at the June 10, 1996, levels and recovery of a major share of transition costs over a 4-year period by December 31, 2001. The stipulated rate freeze will end if recovery is accomplished before 2001.[261] The legislation also provides for additional categories of transition costs to be recovered.[262] Finally, the CPUC was empowered to implement these directives.

Connecticut

Restructuring legislation in Connecticut calls for 35 percent of customers in Connecticut to have electric service provider choice by January 1, 2000, and for all customers to have provider choice by July 1, 2000.[263] Among other issues, the legislation also details how stranded costs in the State are to be handled.

Responsibility for determination of utility-specific stranded costs eligible for recovery rests with the Department of Public Utility Control (DPUC). For utilities to be eligible to recover stranded costs, they are required to submit a plan that includes divestiture of all non-nuclear generating assets through a public

[255] Direct access was originally planned to begin January 1, 1998, but due to operational problems, the date was delayed until March 31, 1998.

[256] Pacific Gas and Electric Company plans to auction and sell its Morro Bay Power Plant, Moses Landing Power Plant, and Oakland Power Plant. These plants have a combined generating capacity of 3,632 megawatts—about 45 percent of the utility's fossil generation capacity (California Public Utilities Commission Press Release, September 3, 1997, CPUC 74 and CPUC 553). Southern California Edison Company sold 10 of 12 of its gas-fired electric generation plants for $1.1 billion, more than twice their book value. The utility still has plans to sell the two remaining plants ("Edison Unloads 10 Gas-Fired Plants for $1.1 billion," *San Diego Union-Tribune*, November 25, 1997).

[257] California Public Utilities Commission, Press Release (September 3, 1997), CPUC 553 and 74.

[258] California Public Utilities Commission, Interim Opinion, Decision 96-08-001 (September 19, 1997), p. 20.

[259] California Public Utilities Commission, Decision 96-08-001, Interim Opinion: Transition Cost Eligibility (September 19, 1997), p. 4.

[260] *Ibid.*, p. 54.

[261] This requirement is primarily for recovery of transition costs relating to generation-related assets and obligations. However, if costs to implement *direct access*, the *power exchange*, and the *independent system operator* reduce the ability of the utilities to collect generation-related transition costs by December 31, 2001, these may continue to be recovered with no set time limit. Costs associated with power purchase contracts, including contracts with qualified facilities in place as of December 31, 1995, are to be collected for the duration of the contract.

[262] AB 1890 includes the following additional categories: transition cost recovery of Biennial Resource Proceeding Update settlement costs, capital additions for units existing as of December 20, 1995 and which the CPUC may consider necessary for maintaining until 2002, Southern California Edison's fixed fuel contracts, and an expanded definition of employee-related transition costs.

[263] Connecticut HB 5005, Public Act 98-28, *An Act Concerning Electric Restructuring* (April 29, 1998).

auction.[264] Utilities are also required to take all possible steps to mitigate potential stranded costs. Subject to these conditions being met to the satisfaction of the DPUC, generation assets (to include nuclear and other generating assets), generation-related regulatory assets, long-term power purchase contract costs, and others qualify for inclusion in stranded cost determinations. A periodic "true-up" process will adjust the assessment annually, or more often if necessary.

Stranded costs will be recovered by imposing a competitive transition assessment (CTA) on all customers, beginning January 1, 2000. The legislation also provides for issuance of rate reduction bonds (RRBs) covering specific stranded costs. Savings from the RRBs must be directly passed on to customers through lower rates. RRBs are to be retired with the proceeds of the CTA prior to December 31, 2011.

Illinois

The Electric Service Customer Choice and Rate Relief Law of 1997 (HB 362), enacted on December 16, 1997, provides choice of electric supplier to non-residential customers by December 31, 2000, and to residential customers by May 1, 2002. All customers will receive rate reductions, with Illinois Power's customers getting the largest reduction of about 20 percent.

Stranded costs are the amount of "revenues lost" by a utility when the electric industry transitions to a competitive environment. These costs will be determined by reviewing net revenues before and after competition, with considerations for mandated rate cuts and mitigation factors. Transition charges will be calculated by taking the base rate and subtracting the following: a 20-percent rate reduction, the mitigation factor,[265] the delivery service charge, and the market price of electricity. The transition period will begin at the onset of competition and continue through 2006. However, a utility may petition the Illinois Commerce Commission to allow a 2-year extension if certain criteria are met.

Stranded cost values will be verified by comparing actual and expected revenues, a procedure which "strengthens monitoring of 'lost revenue' recovery."[266]

Limited securitization is allowed to refinance debt, as long as the bonds mature by the end of 2008.

Maine

Active movement toward electric competition in Maine began in 1995, when a legislative resolve to study the issue was enacted.[267] The Maine Public Utilities Commission (MPUC or the Commission) later submitted recommendations to the State legislature in December 1996 detailing their approach to restructuring the electric industry. MPUC's plan provides all ratepayers the option to select their power suppliers by January 1, 2000.

The Commission's recommendations on stranded costs state that "electric utilities should have a reasonable opportunity to recover legitimate, verifiable, and unmitigable costs stranded as a result of retail access."[268] The Commission plans to design rates permitting utilities an opportunity for cost recovery comparable to that under the current regulation without providing a guarantee for recovery.

According to the Commission, stranded costs consist of above-market costs associated with utility generation, with generation-related contracts, and with regulatory assets.[269] Costs that were incurred imprudently or costs that are not mitigated aggressively will not be entitled to recovery.[270] In fact, the Commission expects the utilities

[264] Utilities may not be able to divest all non-nuclear generation units even with an auction. It is also possible that the non-nuclear assets may sell for more than their embedded cost. Resulting gains are to be used as offsets in determining total recoverable stranded costs. In addition, the legislation stipulates that all generating assets (including nuclear generation assets) be divested by 2004.

[265] The mitigation factor is applied to the base rate less the 20-percent rate reduction. Residential mitigation factors are: 2002, 6 percent; 2003 and 2004, 7 percent; 2005, 8 percent; 2006, 10 percent. Non-residential mitigation factors are 8 percent for the years 1999 through 2002, 10 percent for the years 2003 and 2004, 11 percent for 2005, and 12 percent for 2006 (Illinois Commerce Commission, Summary of HB 362, December 1997).

[266] *Ibid.*

[267] Resolve 1995, Chapter 48, "Resolve to Require a Study of Retail Competition in the Electric Industry," directed the Maine Public Utilities Commission to develop a retail competition plan.

[268] Maine Public Utilities Commission, Docket No. 95-462, *Electric Utility Restructuring: Report and Recommended Plan* (December 31, 1996), p. 105.

[269] According to the MPUC, not all costs that become unrecoverable are "stranded" by retail competition. Customers may undertake conservation, self-generation, fuel-switching, or production cutbacks without the initiation of competition at the retail level.

[270] Among the various options indicated by the MPUC, sale of generation assets offers an opportunity to reduce stranded costs. Note that this approach enables sale of assets that command valuation higher than their book valuation to provide a relief. The Commission did not recommend bankruptcy as a tool to reduce costs.

to obtain the highest value from their generation assets and contracts. Recovery of stranded costs would generally be limited to obligations incurred prior to March 1995.[271]

The Commission plans to estimate stranded costs (using market information to the greatest extent) for each electric utility in the State prior to 2000.[272] These estimates will be used to develop the stranded cost rates to be charged by each utility for transmission and distribution.[273] Since the market price for power will be a critical element in the estimation of stranded costs, the rates so established may be reexamined and readjusted (in 2003 and 2006) on a going-forward basis for each utility separately.

Stranded cost recovery is predicated on the requirement that the State's investor-owned utilities transfer all generation-related assets and activities to corporations distinct from their transmission and distribution businesses by January 1, 2000.[274] Central Maine Power Company and Bangor Hydro-Electric Company are further required to divest all their generation assets by January 2006, or earlier.[275] IOUs are required to file divestiture plans by January 1, 1999, and there will be separate proceedings for each plan.

The MPUC plan was used to help craft legislation. "An Act to Restructure the State's Electric Industry" was signed into law May 29, 1997.[276] The legislation opens the market to competition by March 1, 2000, and closely follows the recommendations of the Commission. Stranded costs are defined as the "verifiable and unmitigable costs made unrecoverable as a result of the restructuring of the electric industry."[277]

Estimates of stranded costs in Maine are not yet complete. Maine Public Service Corporation estimates the costs at $68 million, and Central Maine Power Company's estimate is $2 billion.[278] These estimates will be subjected to MPUC's review.

Maryland

An initial determination made by the Maryland Public Service Commission (MPSC) in 1995 concluded that retail wheeling was not in the public interest at that time.[279] However, in recognition of the rapidly changing nature of the electric industry and issuance of Orders 888 and 889 by the Federal Energy Regulatory Commission, the MPSC opened a staff investigation in October 1996, calling for a detailed report to be submitted by June 1997.[280] Based on the recommendations of the staff report submitted in May 1997,[281] the MPSC opted in favor of a phased-in retail competition beginning in April 1999 and to be fully available to all Maryland residents by April 2001.[282] After the December 3, 1997, order was released, the Maryland Office of People's Counsel filed a Reconsideration Application with the MPSC, raising a number of issues surrounding the Order. The MPSC did reconsider the implementation

[271] Exceptions include the creation of regulatory assets and obligations mandated by the Commission or after the March 1995 date.

[272] The MPUC plans to conduct adjudicatory proceedings to determine stranded costs for each utility and establish transition charges for recovery. These proceedings are to be completed by July 1, 1999. Rate design is to be completed by October 1, 1999.

[273] MPUC stated that it would not establish exit fees or similar charges during restructuring. Depending on the total level of stranded costs determined, customers could see "a half-cent per kilowatt hour credit" or "an additional 1.5 to 2 cents per kilowatt hour charge," according to *The Bangor Daily News* (August 27, 1997).

[274] Maine has three investor-owned utilities (IOUs): Central Maine Power Company, Bangor Hydro-Electric Company, and Maine Public Service Company. The first two are required to sell the rights to the capacity and energy associated with their power purchase contracts. Maine Public Service Company would transfer these rights to its generation affiliate. Consumer-owned utilities in the State are not required to divest or structurally separate generation from transmission and distribution activities. However, certain limitations on their operations have also been imposed.

[275] Maine's utilities will not be required to divest ownership in Maine Yankee—a nuclear power plant—unless its operating life extends significantly beyond 2008.

[276] State of Maine Legislature, H.P. 1274-L.D. 1804 (May 29, 1997).

[277] *Ibid.*, § 3208, 2 (A,B,C).

[278] United States Securities and Exchange Commission, Form 10-K, Maine Public Service Company (September 30, 1997), and Form 10-Q, Central Maine Power Company (March 31, 1997).

[279] Maryland Public Service Commission, Order No. 72136, Case No. 8678, *In the Matter Of the Commission's Inquiry Into The Provision And Regulation of Electric Service, 1995 Regulatory Policies Order* (August 18, 1995).

[280] Maryland Public Service Commission, Order No. 72938, Case No. 8678, *In the Matter Of the Commission's Inquiry Into The Provision And Regulation of Electric Service, 1996 Initiating Order* (October 9, 1996).

[281] Maryland Public Service Commission Staff Report, *A Framework for Customer Choice and the Future Regulation of Electric Services in Maryland*, Case No. 8738 (May 30, 1997).

[282] Maryland Public Service Commission, Order No. 73834, Case 8738, *In the Matter of the Commission's Inquiry into the Provision and Regulation of Electric Service* (December 3, 1997).

dates, and changed the phase-in schedule to begin on July 1, 2000, and to be complete by July 1, 2002.

Estimated stranded costs for Maryland investor-owned utilities are relatively low, at about $1 billion. MPSC staff defines stranded costs as "the difference between the book value of a utility asset and what that asset is worth in a competitive market."[283] Recoverable categories of stranded costs include the unrecoverable capital costs of generating assets, regulatory assets (such as social programs and demand-side management initiatives) and finally, restructuring costs. The Staff report opposes inclusion of nuclear plant decommissioning costs as a component of stranded costs, arguing that these costs should be viewed as operating costs to be recovered from the market selling price of nuclear power output.

The market valuation approach to measuring stranded costs is recommended by the MPSC staff, because it avoids errors from projected future market prices. The Order also recommends that the Commission seek legislative authority for the sale of generation assets.

Utilities in Maryland will be directed to file restructuring plans with the MPSC, including a quantification of stranded costs and the proposed time frame and mechanism to recover costs. In addition, the MPSC recommends a "proxy method for stranded cost level determination to be used in the initial phase-in period should adjudication not be complete at that time."[284] Utilities may propose any methodology for estimating stranded costs, provided they justify the plan adequately reflects the long-term valuation of assets.

Utilities must exercise all "reasonably available measures to mitigate stranded costs."[285] Some suggested mitigation measures include:

- Sale of excess generating capacity
- Sale of SO_2 and NO_x allowances
- Sale of non-developed sites for generating plants included in the rate base
- Accelerated depreciation of assets
- Allowing no new regulatory assets
- Reduced returns on uneconomic assets
- Buyout or renegotiation of existing contractual power purchase agreements with nonutility generators.

The methods for recovery of stranded costs could include a competitive transition charge (wires charge), an exit fee, and securitization. Whatever combination of recovery methods is approved, a true-up process could be included to ensure that recovery is not over or under the level of stranded costs. Utilities are "urged" to include bonds in their future filings if it will save consumers money.[286]

The legislature is planning to take up this issue during the 1998 session. According to former MPSC Chair Russell Frisby, the MPSC has the "authority to move forward on this order without the General Assembly's explicit approval."[287] However, the General Assembly plans to work on legislation during the 1998 session. In the meantime, the Maryland Office of People's Council (OPC) has challenged whether the MPSC has the authority to implement plans for industry restructuring. The MPSC plans to "consider the remainder of OPC's Reconsideration Application at an appropriate time."[288]

Massachusetts

Restructuring of the Massachusetts electric industry began with an order to investigate electric utility restructuring in 1995. A regulatory order was subsequently issued by the Massachusetts Department of Public Utilities, now known as the Department of Telecommunications and Energy (MDTE), on December 30, 1996.[289] Legislation enabling the MDTE to go forward with the order was enacted on November 26, 1997. Customers receive a 10-percent rate cut when competition begins on March 1, 1998.

[283] *Ibid.*, p. 74.
[284] *Ibid.*, p. xvi.
[285] *Ibid.*, pp. 76-77.
[286] *Ibid.*, p. 86.
[287] "Maryland Panel Acts to End Electric Monopolies," *The Washington Post* (December 4, 1997), p. E1.
[288] Maryland Public Service Commission, Case No. 8738, Order No. 73901, *In the Matter of the Commission's Inquiry Into the Provision And Regulation of Electric Service* (December 31, 1997), p. 5.
[289] Massachusetts Department of Public Utilities (now known as the Department of Telecommunications and Energy), *Electric Industry Restructuring Plan: Model Rules and Legislative Proposal*, Order 96-100 (December 30, 1997).

According to the MDTE, stranded costs are "losses which may result from subjecting electric company generation to the pressures of a competitive market."[290] These stranded costs include nuclear decommissioning costs, above-cost purchased power contractual commitments, utility-owned generation assets, and regulatory assets. Stranded cost calculations are to be based on "administrative determinations or market valuation of generating assets, or combinations of the two."[291]

The order allows for full recovery of stranded costs over a 10-year transition period.[292] All stranded costs must be on the books prior to March 15, 1995. However, according to the order, "the obligation of companies to maximize their mitigation of embedded costs is an inseparable component of the Department's policy decision to allow companies a reasonable opportunity to recover stranded costs."[293] Divestiture of assets is preferred by the MDTE since it is the "cleanest way to establish an objective determination of asset value and obtain a maximum level of mitigation."[294] Reconciliation of such costs will take place at the end of years 2, 5, and 10 to compensate for market price changes.[295]

The next step of the MDTE plan required utilities to file restructuring plans, including provisions for stranded costs. Restructuring plans of major utilities in the State have been approved. Massachusetts Electric Company, a subsidiary of the New England Electric System, has an agreement allowing for an initial 2.8 cent per kilowatthour access charge, with this rate being adjusted for changes in the market value of divested assets and estimated costs.[296] Commonwealth Energy System affiliates (COM/Electric) introduced "Competitive Challenge," a plan to minimize the amount of stranded costs by selling its 18 power contracts and its generating assets.[297] Eastern Edison Company's competition plan, settled January 1997, provides for full stranded cost recovery and requires divestiture of the company's assets. In addition, Eastern Edison must separate its distribution system from the parent company's transmission system.[298]

Throughout 1997, a legislative joint committee introduced several bills to deregulate the State's electric industry. The Massachusetts Senate passed H.B. 5117[299] on November 23, 1997, and Governor Paul Cellucci signed the bill into law two days later. The legislation provides a 10-percent cost reduction and allows for the recovery of stranded costs. The MDTE is instructed to complete a comprehensive audit for each investor-owned utility no later than December 31, 1998, to establish what costs are eligible for recovery. Once approved, the transition costs will be subject to a true-up process at least every 18 months, which is a shorter period of time than proposed in the MDTE order. However, the legislation dictates that only the following transition costs be allowed:

- Generation-related assets and obligations that become uneconomic in a competitive electric market
- Nuclear decommissioning costs not recoverable from the funds administered by FERC
- Unrecovered amounts of the reported book balances of generation-related regulatory assets
- The amount of costs over the market price for contractual commitments for purchased power, when the contracts are restructured, renegotiated, or terminated
- Employee-related transition costs.

[290] *Ibid.*, p. 222.
[291] *Ibid.*, p. 289.
[292] The plan acknowledges that "there is no clear legal entitlement to stranded cost recovery." According to the Decision (96-100), "costly litigation of the electric companies' legal challenges to any attempted denial of stranded costs would significantly delay the benefits of competition for consumers."
[293] *Ibid.*, p. 298.
[294] *Ibid.*, p. 297.
[295] *Ibid.*, p. 309.
[296] Department of Telecommunications and Energy, DPU Docket Nos. 96-100 and 96-25, "Restructuring Settlement Agreement" (February 26, 1997).
[297] Com/Electric Press Release, "Commonwealth Energy System Affiliate Moves 'Competitive Challenge' Ahead to Offer Customer Choice in Power Supply" (April 10, 1997).
[298] Eastern Utilities Press Release, "Massachusetts Approves Settlement Agreement for Eastern Edison Competition Plan" (January 5, 1998).
[299] State of Massachusetts, *Bill Relative to Restructuring the Electric Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protection Therein*, H.B. 5117.

H.B. 5117's passage has sparked efforts to repeal the bill. A referendum campaign has been launched to suspend the legislation, and the issue will be put on the November 1998 ballot for possible repeal. If the legislation is repealed, the MDTE will not be able to implement the restructuring order.

Michigan

The Michigan Public Service Commission (MPSC or the Commission) was directed to review and initiate actions to promote competition in electricity by Governor John Engler in January 1996.[300] To meet this requirement, the MPSC staff met informally with numerous interest groups and stakeholders and also held public hearings. These efforts led to the submission of a staff report in December 1996.[301] In June 1997, the MPSC issued its order based on recommendations in the staff report and inputs from stakeholders detailing electricity restructuring promotion in the State.[302] A rehearing of the June order was issued January 14, 1998.

The Commission's definition of stranded costs includes costs that were incurred during a regulatory regime and that will be above market prices during competition. In addition, costs that are incurred to facilitate transition will also be included. Costs that become eligible for recovery will be the sum of these two costs.[303]

Based on the above definition of stranded (or transition) costs, the Commission stipulated that costs that would become eligible for recovery would be limited to five categories:

- Regulatory assets, including unrecovered costs of demand-side management programs, plant abandonment costs, unfunded pension and health benefit liabilities, deferred tax liabilities, and other similar costs
- Capital costs of nuclear plants[304]
- Contract capacity costs arising from power purchase agreements
- Employee retraining costs
- Costs related to implementing restructuring, including implementing a direct access program, establishing an independent system operator, and creating new billing and metering systems.

Full recovery of stranded costs in the above five categories is to be allowed. Recovery, according to the Staff Report, may either be through securitization or through a transition charge that would begin when the customer takes direct access and continue through 2007, or through both. However, the Commission did not specifically recommend securitization other than stating that it may be a viable option if it would bring about a reduction in customer rates.[305]

Utilities operating in Michigan made informational filings with the MPSC indicating the amount of stranded costs to be recovered by each, together with the transition charges (with or without securitization) to be imposed. The two largest utilities in the State—Detroit

[300] Michigan Jobs Commission's report—*A Framework for the Electric and Gas Utility Reform*—submitted to Governor Engler in December 1995 identified the cost of power in Michigan as a negative factor discouraging new businesses from moving into the State. With a view to remedy this situation, the report contained recommendations to be adopted by the Michigan Public Service Commission. It was this report that the Governor forwarded to the MPSC for review and action. (Letter dated December 20, 1995, from the Michigan Jobs Commission to Governor John Engler and letter dated January 8, 1996, from the Governor to the MPSC.)

[301] Staff of the Michigan Public Service Commission, *Staff Report on Electric Industry Restructuring* (December 19, 1996).

[302] Michigan Public Service Commission, *In the Matter, on the Commission's Own Motion, to Consider the Restructuring of the Electric Utility Industry*, Case No. U-11290 (June 5, 1997).

[303] The *Staff Report* states that the stranded (or transition) costs include "regulatory assets, societal costs (costs incurred for various social programs), restructuring costs (those incurred specifically to allow competition to proceed, such as the cost of creating an independent system operator), and above-market cost of purchased power contracts previously approved by the Commission, and power supply facilities acquired under the "obligation to serve" principle. Staff of the Michigan Public Service Commission, *Staff Report on Electric Industry Restructuring* (December 19, 1996), p. 13 .

[304] According to the Commission, the combination of performance-based regulation and mitigation efforts during the transition period would render it unnecessary to recognize the capital costs of other plants.

[305] Various operational procedures need to be in place for securitization to function besides the establishment of a trust fund and a legislative mandate for issuance of bonds. The Commission did not take a position on many of the issues associated with securitization other than conceding that it may be a viable option subject to certain requirements being met. Refer to Michigan Public Service Commission, *In the Matter, on the Commission's Own Motion, to Consider the Restructuring of the Electric Utility Industry*, Case No. U-11290 (June 5, 1997), p. 16.

Edison Company and Consumers Energy Company—propose to recover a total of over $5 billion in stranded costs. Claims of two other smaller utilities are less than $100 million in stranded costs.[306] In a rehearing of the June 5, 1997, Order, the Commission calculated stranded cost levels for both Detroit Edison and Consumers Energy. Detroit Edison's stranded costs are estimated at $1,755 million, and those of Consumers Energy at $2,483 million.[307]

Critics fault the approach used in estimating stranded costs for several reasons. They contend that the assumptions used for the market price of power tend to inflate utilities' stranded cost estimates; that "stranded benefits" of low-cost generating plants remain unaccounted; and that incentives to mitigate costs—even though acknowledged—are missing. Several commenters asserted the view that the procedures for stranded cost recovery may result in the guaranteed full recovery of all costs even if they were not prudently incurred.

In its Order, the Commission stated that imprudent costs will not be included in the determination of stranded costs. Plans for a true-up mechanism to adjust stranded cost estimates annually were also initiated by requiring Detroit Edison and Consumers Energy to file proposals for establishing the mechanism. The process involves verifying that estimated stranded costs reflect actual costs. Thus, distortions introduced by lower market prices of power could be eliminated.

An interesting feature of the Commission's Order is the phase-in schedule to be implemented in the State. The Commission's original June 5, 1997, Order envisions that approximately 2.5 percent of each utility's retail load will become eligible in 1997, with an additional 2.5 percent of load eligible in each of the years from 1998 through 2001. By the end of the phase-in period, 12.5 percent of each utility's retail load will be eligible for customer choice. However, in the rehearing of the Order,[308] the phase-in schedule was delayed to begin on March 31, 1998. By January 1, 2002, all customers are eligible to participate in this access plan. If a utility receives more applications for load than contemplated in the phase-in, an allocation of the available capacity will take place. The Staff Report recommended "the use of a bidding process in which customers would submit a sealed bid indicating the amount, above or below the stated transition charge, that they would pay instead of that charge until all customers in their class are eligible for direct access. At that time, the customers begin to pay a cost-based transition charge and all bid amounts collected would be used to offset stranded costs."[309] Transition charge amounts were determined January 14, 1998. Consumers Energy's charge to its customers will be 1.20 cents per kilowatthour, and Detroit Edison's charge was set at 1.25 cents per kilowatthour. The Commission did not favor a faster phase-in schedule as it would increase the potential magnitude of stranded costs. By 2002, all customers will have the option of choosing an alternative supplier.

The Commission's Order has not been without controversy. Commissioner John Shea filed a dissenting opinion, questioning the Commission's authority to issue the Order. Consumer groups expressed their disappointment at the length of the transition period and phase-in rates. Utilities' informational filings were also contested. The actual "ground rules" for the restructuring were ordered on October 29, 1997. [310] Orders on retail access tariffs, stranded cost true-ups, performance-based ratemaking, and power supply cost reviews were approved, with the dissention of Commissioner Shea. The retail access tariff orders for Detroit Edison and Consumers Energy required both to submit revised direct access tariffs within 14 days of the October 29, 1997, order.[311] Both companies are petitioning for a rehearing of the tariff orders and have refused to submit revised tariffs by the deadline of November 12, 1997. Without modifications to the orders, Detroit Edison "declines to participate" in the program as ordered.[312] The January 14, 1998, Order requires Consumers and Detroit Edison to file revised tariff sheets by January 28,

[306] Consumers Energy and Detroit Edison were required to submit informational filings prior to March 7, 1997, to give the MPSC a clear view of the status of stranded costs in Michigan. Other utilities were not required to file, but could file if they chose. In addition to the two required filings, Alpena Power Company and Wolverine Power Corporation voluntarily submitted reports.

[307] Michigan Public Service Commission, *In the Matter, on the Commission's Own Motion, to Consider the Restructuring of the Electric Utility Industry*, Case No. U-11290 (January 14, 1998), p. 14. These figures assume the market price of electricity to be 2.9 cents per kilowatthour and that all residents of Michigan will choose to participate in the open access plan.

[308] *Ibid.*, p. 10.

[309] Michigan Public Service Commission, *In the Matter, On the Commission's Own Motion, to Consider the Restructuring of the Electric Utility Industry*, Case U-11290, Opinion and Order (June 5, 1997).

[310] Michigan Public Service Commission News Release (October 29, 1997). Orders were issued in six contested cases in order to continue introducing competition into the Michigan electric market.

[311] Michigan Public Service Commission, Decisions 11451 and 11452 (October 29, 1997).

[312] "Detroit Ed., Consumers Energy Attack PSC Retail-Access Orders, Ask Review," *Electric Utility Week* (November 17, 1997), pp. 13-14.

1998.[313] This rehearing of the June and October 1997 Orders is expected to be appealed by several parties.[314]

It should, however, be noted that the Commission's Order is essentially a first step in the restructuring process. The rest is up to the State legislature, where restructuring legislation has not yet been introduced.

Montana

The Montana Electric Utility Industry Restructuring and Consumer Choice Act, SB 390, was signed into law by Governor Marc Racicot on May 2, 1997. This bill directs the Montana Public Service Commission (PSC) to implement electric competition in Montana no later than July 1, 2002. The legislation also includes a 2-year rate freeze beginning July 1, 1998, and an additional 2-year rate freeze on energy components of bills for residential and commercial customers. Investor-owned utilities must functionally separate their electric supply, transmission, and distribution services, but without the requirement to divest assets.

SB 390 defines "transition" costs as a public utility's net verifiable generation-related and electricity supply costs (including costs of capital) that become unrecoverable as a result of transition to competition.[315] The legislation gives examples of these transition costs, including:

- Regulatory assets
- Nonutility and utility power purchase contracts, including qualifying facility contracts
- Generation investments and supply commitments
- Costs of renegotiation or buyout of existing nonutility and utility power purchase contracts, including qualifying facility contracts and fees related to issuing transition bonds
- Cost of refinancing and retiring debt or equity capital of the utility.

Investor-owned utilities in the State are mandated to prepare applications for recovery of transition (stranded) costs for approval by the PSC. After a review and hearing, the PSC will issue an order approving, denying, or modifying the utilities' requests for recovery. Individual utility approval of stranded cost recovery is predicated on the successful demonstration that all reasonable efforts to mitigate costs have been exhausted.

Valuation of transition charges should be reasonably quantified and determined on a net basis. This determination may be based on (but not limited to) one of the following:

- Estimated future market values of electric energy and ancillary services produced by a utility
- Appraised values by an independent third party
- A competitive bid.

The legislation stipulates that recovery of costs approved by the PSC will be through a nonbypassable charge on all customers. However, loads served by customers' self-generation or new customers with loads of 1,000 kilowatts or greater, that were first served by the utility after December 31, 1996, will be exempt from collection of this charge.

Recovery of transition costs would be limited to a period determined by the PSC on case-by-case basis. SB 390 stipulates the recovery period to begin on July 1, 1998, and to end on July 1, 2002, unless otherwise extended. As stated earlier, utilities will be required to implement a rate moratorium during the transition cost recovery period. During the period of transition cost recovery, utilities have been permitted to exercise certain changes in accounting procedures so that a 9.5-percent return on equity is maintained.

The legislation also permits utilities to apply for recovery of certain transition costs through the issuance of transition bonds or securitization, subject to the PSC's approval on a case-by-case basis. These bonds are to be secured through the revenues of a nonbypassable charge on all customers. In order for the request to issue a bond to be considered, the utility must demonstrate the resulting savings benefit for the ratepayers.

A special legislative session to consider delaying the restructuring of the electric industry was contemplated

[313] Michigan Public Service Commission, *In the Matter, on the Commission's Own Motion, to Consider the Restructuring of the Electric Utility Industry*, Case No. U-11290 (January 14, 1998), p. 30.

[314] "S&P Update on Michigan Electric Utility Restructuring," *Business Wire* (January 16, 1998).

[315] SB 390, *The Montana Electric Utility Industry Restructuring and Consumer Choice Act*, Section 3, No. 22 (A-B) (May 2, 1997).

by some Montana lawmakers. However, the legislature voted not to hold a special session and affirmed the restructuring. In the meantime, Montana Power begins its asset sale during 1998.

Nevada

Electric industry restructuring legislation was enacted in Nevada in July 1997 and sets December 1999 as a target date for electric competition. Assembly Bill 366 empowers a newly reorganized Public Utilities Commission (NPUC) to initiate rulemaking on issues to be resolved prior to the start of competition. "Shareholders of a vertically integrated electric utility must be compensated fully" for past costs that may become unrecoverable in a competitive environment, according to the legislation.[316] The NPUC is responsible for identifying and estimating unrecoverable past costs.[317]

The legislation requires the NPUC to consider the following in determining the level of "recoverable costs" in Nevada:[318]

- Extent to which the utility was legally required to incur asset and obligation costs
- Extent to which the market value of utility assets and obligations may exceed the embedded costs under competition
- Results of mitigation techniques adopted by the utilities in reducing the recoverable cost levels and the extent to which equity holders have been compensated by NPUC's rate setting policies in the past.

The legislation is silent on some relevant issues, including uneconomic power purchase costs and whether securitization will be permitted.[319] These omissions may not pose a problem given the low level of potential stranded costs in the State. In the meantime, the NPUC has opened a docket on implementing various provisions of AB 366.[320]

New Hampshire

In May 1996, New Hampshire enacted legislation requiring the New Hampshire Public Utilities Commission (NHPUC or the Commission) to develop and implement a State-wide electric utility restructuring plan.[321] The legislation makes retail choice available to all customers by January 1, 1998. For this objective to be achieved, the General Court provided a list of restructuring principles together with guidance regarding implementation.

The legislation also provides the NHPUC with tools and guidance to address stranded cost recovery claims in a manner that balances "the interests of ratepayers and utilities during and after the restructuring process."[322] New Hampshire's HB 1392 defines stranded costs as "costs, liabilities, and investments, such as uneconomic assets, that electric utilities would reasonably expect to recover if the existing regulatory structure with retail rates for the bundled provision of electric service continued and that will not be recovered as a result of restructured industry regulation that allows retail choice of electricity suppliers, unless a specific mechanism for such cost recovery is provided." The legislation limits elements of stranded costs to include existing commitments or obligations, renegotiated commitments, and new mandated commitments. Procedures to be adopted for recovery of stranded costs are also specified.[323] Utilities are, however, obligated to take all reasonable measures to mitigate stranded costs.

Following the enactment of HB 1392, the NHPUC issued a *Preliminary Plan* in September 1996 seeking stakeholder input on various key goals (including the recovery of stranded costs) of industry restructuring in New

[316] "Past Costs" are costs that have not yet been recovered and were incurred in the past for customers whom the utilities were legally obligated to serve. Past costs and unrecoverable costs both are terms used in place of the more widely used term "stranded costs."

[317] Known as Public Service Commission of Nevada prior to October 1997.

[318] Assembly Bill 366, *An Act Relating to Governmental Administration*, Enacted Version (July 16, 1997), Section 46.

[319] A study undertaken by the NPUC includes the following categories of costs: generation and power supply contract costs, regulatory assets, and public policy costs. *The Structure of Nevada's Electric Industry: Promoting the Public Interest*, Chapter 6 (June 1996).

[320] Public Service Commission of Nevada, Docket No. 97-8001 (October 1997).

[321] New Hampshire House Bill 1392 (RSA Chapter 374-F), *An Act Restructuring The Electric Utility Industry in New Hampshire and Establishing a Legislative Oversight Committee*, was enacted on May 16, 1996. HB 1392 consists of policy principles that the NHPUC is required to implement. Critical among the issues are system reliability, customer choice, unbundling of services and rates, recovery of stranded costs, environmental improvement, and near-term rate relief.

[322] New Hampshire HB 1392, Chapter 374-F:3.

[323] Two recovery mechanisms—for the long and short term—by which stranded costs could be recovered are also detailed in the legislation.

Hampshire.[324] During the next few months, the Commission reviewed written comments, evaluated briefs, held hearings, and provided information in public forums on various issues with respect to proposed industry restructuring in the State. These activities culminated in issuance of the *Final Plan* by the Commission on February 28, 1997.[325]

The preliminary and the final plans announced by the NHPUC are unique in articulating a policy decision denying full recovery of transition-related stranded costs.[326] The Commission linked recovery of a utility's stranded costs to the average electricity prices in the New England region. Utilities at or below the regional average electricity cost will be allowed a greater opportunity to recover net, verifiable, nonmitigable stranded costs than utilities with electricity prices above the regional average.

Elements of the Commission plan for recovery of stranded costs include the following:

- Recovery of stranded costs is to be based on a determination of responsibility regarding the acquisition of resources (or assets). Full recovery would be permitted only in those cases where the utility management discretion over resource acquisition was reduced or eliminated by government mandates. In all other cases, where utility management was responsible for resource acquisition decisions, stranded cost recovery would be limited.

- The Commission defined stranded cost on the basis of "net" sunk generation cost (including generation-related regulatory assets) that may not be recoverable when consumers are allowed the choice of reaching alternative suppliers.

- After taking into account various approaches to measure stranded costs, the Commission concluded that a sale or spinoff of generation assets would be the most accurate and reliable method.[327]

- All jurisdictional utilities in the State are required to submit plans by December 31, 1997, to accomplish divestiture by the end of the 2-year period following the implementation of competition.

- In line with the provisions of HB 1392 (requiring the utilities to pursue maximum mitigation of stranded costs), the Commission stressed options for mitigation strategies, to include: maximization of the value of assets and contracts through sale or spinoff, the financial management of stranded costs, and the application of other company value to reduce residual stranded costs.

- With respect to stranded costs from assets (like regulatory assets) that have no market value, the Commission suggested strategies to include writedowns, reamortization, and securitization.[328] The Commission, however, recommended that the Legislature should carefully weigh the benefits and drawbacks to securitization.[329]

- Determination of stranded costs (that jurisdictional utilities will be allowed to recover) would be tied to the competitive regional electric rates in the New England region. Utilities with rates higher than the regional average will not be able to recover all their stranded costs. In prescribing this mode, the Commission made the following points: less than full stranded cost recovery is fair; less than full stranded cost recovery is not

[324] New Hampshire Public Utilities Commission, Docket No. 96-150, *Restructuring New Hampshire's Electric Utility Industry: A Preliminary Plan* (September 10, 1996).

[325] New Hampshire Public Utilities Commission, Docket No. 96-150, *Restructuring New Hampshire's Electric Utility Industry: Final Plan* (February 28, 1997).

[326] The *Final Plan* advocates a market structure to provide customers with the opportunity to purchase their electricity directly from competitive suppliers. Stranded cost and public policy issues are the two critical adjuncts of the proposed transition.

[327] The Commission claims that applying this approach allows elimination of vertical market power.

[328] Writedowns and reamortization involve changing the timing and return on collections. Securitization aims to reduce stranded cost charges by off-balance-sheet financing with higher debt security and consequently lower cost financing. Securitization may be used to reamortize indebtedness as well.

[329] One of the main benefits of securitization is that it permits the utilities to lower costs immediately due to a reduction in financing costs. It also lends them security with regard to recovery of assets with no market value. On the negative side, it reduces incentives for mitigation in the future. NHPUC noted that securitization further institutionalizes costs which could otherwise be mitigated or absorbed during a possible industry reconsolidation (mergers or acquisitions).

economically inefficient; and full recovery of stranded costs has anti-competitive effects.[330]

- Based on State legislation, the Commission did not lend its support to imposing exit fees to recover stranded costs. As an alternative, recoverable costs should be allocated fairly and consistently among customer classes. Stranded cost charges—in conformity with the legislative mandate in HB 1392—are nonbypassable and nondiscriminatory. These charges, however, may not apply to self-generation customers leaving the grid.

- Interim stranded cost charges, to be determined for each jurisdictional distribution utility, will be effective for a 2-year period following the implementation of a company's compliance filing. Interim stranded cost charges will be calculated as a function of the prevailing average price in the New England region.[331] The guiding principles articulated by the State legislature are to be applied in setting interim stranded costs.[332]

The Commission's approach to the handling of stranded costs (in conformity with the legislative directives in HB 1392) has proved to be controversial. The Public Service Company of New Hampshire (PSNH), a subsidiary of Northeast Utilities, sought a restraining order to prevent the restructuring plan from being implemented.[333] An attempt to resolve the outstanding issues with the help of a mediator has since failed, and the NHPUC is proceeding with a rehearing. A new proposal submitted by the State to help end the restructuring deadlock would allow PSNH to recover 90 percent of its stranded costs using a cost-based approach. Stranded cost recovery would be stretched over 12 instead of 10 years and would use securitization for a 20-percent rate cut.[334] Details of the arrangement are still being negotiated.[335] The target date for the restructuring plan, originally January 1, 1998, has since been delayed due to the legal entanglements related to stranded cost recovery.

New Jersey

In its April 1997 report presented to the Governor and the New Jersey State Legislature, the New Jersey Board of Public Utilities (BPU) provided specific findings and recommendations to restructure the electric power industry in the State, with the intent to open the electric market to all retail customers by July 2000.[336] In promoting restructuring and the transition to competition, one of the critical issues that confronted the BPU was how to deal with the utilities' stranded costs. These are costs, "related to the generating capacity in utility rates, which the utility is at risk of being unable to recover if the supply market is opened to competition."[337]

Stranded costs in New Jersey, according to BPU, are driven by two factors: the high construction and operating costs of nuclear power plants in the State and the long-term, high-cost supply contracts with nonutility generators and independent power producers. Depending on the assumptions made regarding the future market price for electricity in New Jersey, estimates of stranded costs in the State range "from \$7 to \$17 billion."[338]

[330] The Commission released an extensive legal analysis (as an adjunct to the Final Plan documentation) that supports limiting recovery of stranded costs by applying the regional average price in New England utilities as a benchmark. The operational impact of this procedure is to allow jurisdictional utilities with rates lower than the regional average in the New England region to fully recover their stranded costs. The Commission, however, agreed to permit full recovery of nonmitigable costs of purchasing power from small power producers unless the purchases were discretionary.

[331] On October 16, 1996, the NHPUC determined in Order 22,364 that the setting of interim stranded costs involved issues of facts and as a result would be the subject of adjucative style hearings. The Commission also retained La Capra Associates—a consulting firm—to provide estimates of long-term and interim stranded costs for each jurisdictional utility in New Hampshire. See La Capra Associates, *Estimates of Electric Utility Stranded Costs Associated with the Introduction of Retail Competition in the New Hampshire Generation Service Market* (Boston, January 3, 1997).

[332] HB 1392 authorizes that the stranded cost charges are to be determined in the context of rate proceedings and must be: (a) equitable, appropriate and balanced, (b) in public interest, and (c) substantially consistent with restructuring principles contained in HB 1392. For purposes of setting interim stranded cost charges, the legislation permits the Commission to make preliminary determinations

[333] Note that the overall level of estimated long-term stranded costs for all electric utilities in the State range from \$2.0 billion to \$2.6 billion depending on the assumptions made. However, nearly 78 percent of these costs are recoverable by the PSNH, with the remaining amount unevenly distributed among four other utilities. Refer to La Capra Associates, *Estimates of Electric Utility Stranded Costs Associated with the Introduction of Retail Competition in the New Hampshire Generation Service Market* (Boston, January 3, 1997), pp. 35-36.

[334] "New Hampshire Concedes to Higher Stranded Cost Recovery for PSNH," *Electric Utility Week* (October 13, 1997), p. 11.

[335] New Hampshire Public Utilities Commission, Decision 96-150, Order No. 22,875 (March 20, 1998).

[336] New Jersey Board of Public Utilities, *Restructuring the Power Industry in New Jersey, Findings and Recommendations,* Docket No. EX94120585Y (April 30, 1997).

[337] *Ibid.*, p. 9.

[338] *Ibid.*, p. 10.

With a view to prevent a drastic deterioration in the financial health and viability of the utilities, the BPU proposed that the utilities be given an opportunity, for a limited number of years, to recover generation-related stranded costs through electricity rates. Other sources of stranded costs like regulatory assets, social programs, and restructuring costs (including downsizing) were deemed to be not at risk due to the introduction of competition and could be addressed through traditional ratemaking mechanisms. Nuclear decommissioning costs were also excluded, because industry restructuring did not jeopardize this funding in the future.

Without offering 100 percent recovery, eligibility for recovery of stranded costs was qualified by a number of conditions. Utilities operating in the State are required to offer a near-term rate reduction benefit to a minimum of 5 to 10 percent to the State's customers concurrent with unbundling of rates.[339] Subject to this condition being met, determination of the actual levels of stranded costs and the proposed recovery amount will be decided on a case-by-case basis for each utility.[340]

The State has made modifications to the existing method of tax collection from utilities to permit further lowering of electricity rates. The Energy Tax Reform Bill, enacted on July 14, 1997, reduces existing energy tax rates by 45 percent over 5 years.[341] Instead of paying the gross receipts and franchise tax, energy consumers in New Jersey will now pay a sales tax, a corporation business tax, and a transitional energy facility assessment (TEFA). The TEFA will then be phased out over 5 years, and by January 2003, energy tax rates should decrease from 13 percent to 7 percent, saving consumers 6 percent on their energy costs. Combined with the mandatory 5- to 10-percent rate reduction and possible securitization, the tax savings should bring consumers total savings of between 10 and 15 percent.[342]

Utilities are also obligated to use all possible measures to mitigate the level of stranded costs, including the sale of excess generating capacity, accelerated depreciation of assets, reduced return on uneconomic assets, and the buyout or renegotiation of existing power purchase contracts. Tax implications resulting from such measures are also to be taken into account.

The BPU also considered securitization as a mechanism in addressing stranded costs.[343] The operational impact of introducing this method of mitigation results in significant interest cost savings, which can be passed on to ratepayers in the form of lower rates. The BPU, however, noted that the resulting savings should not serve as the sole source for rate reductions that were projected or being sought.

Implementing securitization would, however, require enabling legislation and would offer only a partial solution to the stranded cost problem. An upper limit would have to be placed on securitized debt. Proceeds from securitized bonds must be used to reduce generation-related stranded costs and not to subsidize any other activity. In the event that securitization is authorized, recovery of necessary revenues will be reflected in a separate surcharge.[344]

The BPU's position thus envisages recovery of some but not all components of stranded costs. A specific, non-bypassable market transition charge (MTC) established for each utility will be used to recover approved stranded costs, with its duration ranging between 4 to 8 years.[345] The MTC will be a separate component of a customer's bill.

Determining an MTC level and period of duration depends on estimates of stranded costs. One process of establishing estimates is to find the market value through a divestiture of utility generation assets. However, the BPU did not mandate this method for adoption even though GPU plans to implement a partial

[339] Utilities may also be allowed to finance rate reductions through securitization as approved by the State Assembly.

[340] *Ibid.*

[341] New Jersey Board of Public Utilities Press Release, "BPU Implements Energy Tax Reform Law That Will Cut Energy Tax Rates by 45 Percent Over 5 Years," December 17, 1997.

[342] New Jersey Board of Public Utilities, *Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations*, Docket No. EX94120585Y (January 16, 1997), p. 12.

[343] *Ibid.*, p. 11. Securitization involves, as discussed elsewhere in this report, the financing of stranded costs, up to a specified limit, by issuance of debt and subsequently liquidating it through a surcharge on the utility's customers.

[344] In restructuring plans submitted in July 1997, "all four of New Jersey's power providers—Public Service Electric & Gas Co., GPU Inc., Atlantic City Electric Company, and Rockland Electric Company—support the idea of borrowing to recoup stranded costs." The bulk of the securitization is proposed by Public Service Electric & Gas Co., which filed to securitize $2.5 billion of its estimated $5.5 billion in stranded costs." "New Jersey's Private Utilities May Use Debt to Cushion Stranded Costs," *American Banker* (July 18, 1997).

[345] Utilities will no doubt prefer a surcharge that would coincide with the life of outstanding power purchase contracts. Where such contacts cannot be renegotiated, extensions to the MTC charge may be necessary.

divestiture of its generating assets in Pennsylvania and New Jersey.[346]

Enabling legislation is required for the BPU to implement its recommendations, because the Board does not have the authority to establish competitive rates. Herbert Tate, BPU President, has said that "we would like to see the legislation supporting the new competitive marketplace enacted no later than July of 1998."[347]

New York

The New York Public Service Commission (NYPSC or the Commission) commenced proceedings to investigate the future regulatory regime for the provision of electricity in the State in early 1993.[348] Within the framework of proceedings that followed, the Commission found stranded costs to be the most contentious issue.

On May 20, 1996, the Commission's investigations led to the issuance of a decision aimed to increase competition in the electric industry in the State.[349] Stranded costs are defined as "those costs incurred by the utilities that may become unrecoverable during the transition from regulation to competitive market for electricity."[350] These include "prudent and verifiable expenditures and commitments made pursuant to [utilities'] legal obligations" in a regulatory environment.[351] This characterization enables the inclusion of operation and maintenance expenses, fuel costs, and purchasing power costs (in addition to investments that are prudent and verifiable) that may also become unrecoverable in a fully competitive market.

However, full recovery of stranded costs is not guaranteed. Rather, the Commission's focus is on the reasonable expectations of utility shareholders in obtaining recovery of their past investments.[352] In addition, the Commission expects utilities and independent power producers to creatively reduce the amount of strandable costs before they are considered for recovery. For example, Niagara Mohawk Power Corporation plans to sell its $1 billion fossil-fueled and hydroelectric generating assets to decrease debt.[353] The adoption of mitigation strategies assumes a critical role in the recovery process. Stakeholders and the Commission have suggested a variety of creative ways to reduce (or mitigate) potentially strandable costs. Establishment of incentives and restructuring of above-cost power purchase contracts are included as possible options.[354]

While the Commission recognized alternative ways of measuring strandable costs, it also noted that the State's investor-owned utilities differ considerably in strandable costs, mostly due to the level of investment in nuclear plants and the amounts of above-market power purchase contracts. Accordingly, the "calculation, the amount to be recovered from ratepayers, and the timing of the recovery" would be left to individual rate cases beginning in 1996.[355] As such, the level of stranded cost recovery will depend on the specifics of each utility. In adopting this approach, the Commission's objective is to create a balance between customer and utility interests and expectations.

Recognizing that the long-run projections of market prices and asset valuations become "highly contestable" beyond a 3-year point, the Commission recommended

[346] GPU opened an auction for 5,320 megawatts of 26 fossil and hydro plants in Pennsylvania and New Jersey on April 15, 1998. See "GPU Markets Its Power Generation Assets to Bidders," *Asbury Park Press* (April 16, 1998).

[347] A.S. Twyman "Energy Deregulation Has Language All Its Own for New Jersey Lawmakers," *The Star-Ledger* (December 31, 1997).

[348] New York Public Service Commission, Case 93-M-0229, *Proceedings on Motion of the Commission to Address Competitive Opportunities Available to Customers of Electric and Gas Service and Develop Criteria for Utility Responses*, Order Instituting Proceeding (March 19, 1993). The case number was subsequently changed to 94-E-0952 to reflect that the subject matter is limited to electric service.

[349] New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Opinion and Order (May 20, 1996).

[350] *Ibid.*, p. 46.

[351] New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Opinion 95-7: Opinion and Order Adopting Principles to Guide the Transition to Competition (June 7, 1995), Appendix C, p. 2.

[352] New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Staff Position Paper (October 25, 1995), p. 38.

[353] The auction is part of the restructuring plan worked out with Niagara Mohawk in October 1997 and filed with the Public Service Commission on December 1, 1997. The NYPSC approved the restructuring plan in February 1998.

[354] The Commission staff estimated that the above-market costs of power purchase contracts (by the utilities in the State) account for nearly 38 percent of the estimated stranded costs. Somewhat lower estimates of above-market power purchase costs were provided by the Energy Association. See New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Recommended Decision (December 21, 1995), Vol. I, p. 77.

[355] New York Public Service Commission, Case No. 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Recommended Decision (December 21, 1995), Vol. I, p. 108.

that calculations of reasonable and verifiable strandable costs be subjected to revisions at specific intervals.[356] Such revisions of stranded costs would permit modification and implementation of mitigation strategies to conform to opportunities arising with the passage of time.

Recovery of nonmitigable stranded costs will be accomplished by a nonbypassable access charge or wires charge imposed by the distribution company.[357] Exit fees were not considered due to their perceived anticompetitive effects.[358] Keeping the recovery period as short as possible in order to accelerate the advent of market prices was a preferred option recommended by the Commission staff.[359]

The Commission's method of handling stranded costs did not find favor with the State's utilities. In September 1996, the Energy Association (EA) of New York State and its seven electric utility members filed a petition in the New York Supreme Court challenging the Commission's decision regarding the treatment of stranded cost recovery (among other issues). EA claimed that the utilities were entitled, as a matter of law, to recover all competitive losses, implying that the utilities should be able to recover every dollar lost in transition to competition. The Supreme Court ruling rejected EA's claims on November 25, 1996.[360] This ruling has been appealed. In the meantime, the Commission is continuing to move the restructuring effort forward as planned.

The preliminary NYPSC estimate of total stranded costs is $16.8 billion, including $3.1 billion for utility generation assets, $6.4 billion associated with power purchase contracts, and $7.3 billion for regulatory assets.[361] For various reasons, however, the accuracy of these estimates is difficult to establish due to the assumptions used in their derivation. Other estimates of strandable costs in New York range from $14 billion to $25 billion.[362] Securitization has been discussed as a possible option to reduce the level of transition costs. Legislation supporting securitization was proposed in June 1996. The proposal would securitize nonmarketable, intangible expenditures into "intangible property."[363] The cost of repaying securitized debt would be added to the cost of providing transmission and distribution services to all users. Enactment of the legislation would allow utilities to borrow money on the strength of a State guarantee, lowering the interest rate. This would permit rates to be lowered immediately as the cost of borrowing for the utilities declines.[364]

Critics view the legislative proposal to securitize differently and observe that the bill has a number of problems as initially submitted, including the perpetuation of high rates and a delay of competition.[365] The magnitude of projected rate savings attributable to securitization is also stated to be questionable. The legislation failed to secure passage but is likely to be introduced again.

In the meantime, utilities have filed their restructuring plans with the Commission.[366] Each utility included a

[356] As an example, the Commission staff and the Energy Association presented independent estimates of the magnitude of strandable costs in the State from transition to competition. These two estimates initially indicated an approximate difference of nearly $12.5 billion. Refer to New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Brief on Exceptions (January 19, 1996), p. 33 and Appendix B-2.

[357] The Commission rejected a clarification sought by the Municipal Electric Utilities Association that recovery of stranded costs be through a distribution surcharge on a departing customer. Rather, the Commission would prefer to retain the flexibility to design a mechanism for recovery in accordance with the specific situation existing with each utility. State of New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Opinion No. 96-17: Opinion and Order Deciding Petitions and Clarification and Rehearing (July 17, 1996), p. 11.

[358] New York Public Service Commission, Case 94-E-0952, Recommended Decision, *In the Matter of Competitive Opportunities Regarding Electric Service*, Volume I, p. 77.

[359] New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Recommended Decision (December 21, 1995), Vol. I, p. 80.

[360] *In the Matter of The Energy Association, et al. vs. Public Service Commission*, New York State Supreme Court, Decision 5830-96 (November 25, 1996).

[361] New York Assembly, "Competition Plus: Energy 2000" (March 1996), p. 15.

[362] New York Public Service Commission, Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service: Brief on Exceptions* (January 19, 1996), Appendix B-1.

[363] New York State Assembly, *Shedding the Light on Securitization: A Briefing Paper on Moving to Competition in the Electric Industry* (January 1997).

[364] In testimony before the New York State Senate Energy Committee, the New York State Consumer Protection Board stated that securitization would bring about a 5- to 10-percent rate cut.

[365] A number of arguments opposing the proposed bill can be found in the Assembly briefing paper. Refer to New York State Assembly, *Shedding the Light on Securitization: A Briefing Paper on Moving to Competition in the Electric Industry* (January 1997).

[366] Lilco was not required to file a plan due to its pending merger with Brooklyn Union. The merger has since been approved.

discussion of the stranded costs that they request be recovered. Most would like to dedicate earnings in excess of a given rate to be used in writing down asset valuations. Consolidated Edison Company, New York State Electric and Gas Company, Niagara Mohawk Company, and Orange and Rockland Utilities will divest assets in order to determine stranded costs stemming from generating facilities. Rochester Gas & Electric, however, is not required to divest, but will use revenues over a certain percentage to offset stranded costs. Assets for Long Island Lighting Company are expected to be acquired by the Long Island Power Authority. These plans differ in details and are based on the specifics of each case. How these plans will be treated if the legislation fails to enact securitization remains to be seen.

Oklahoma

Oklahoma Governor Frank Keating signed S.B. 500 into law on April 25, 1997, mandating retail choice for all customers by 2002.[367] The bill sets goals and forms a framework for a restructured electric industry in Oklahoma. In addition, the legislation directs the Oklahoma Corporation Commission (OCC) to undertake studies of various relevant subjects pertinent to the transition of the industry. Reports will be completed by task forces within the OCC and are due in 1998, 1999, and 2000.

The legislation recognizes problems stemming from the existence of stranded costs. Defining stranded costs as investments and contracts which may be unrecoverable under competition, the legislation directs that procedures for the identification and quantification of such costs be established by the OCC. It further directs that mechanisms be proposed for recovery of an appropriate amount of prudently incurred, unmitigable, and verifiable stranded costs and investments. Each utility will be required to propose a recovery plan including a limited recovery period. The plans are subject to the requirement that the proposed recovery does not lead to an increase in electric rates and that recovery costs be paid for by all customers, not just those switching suppliers.[368]

Direct access by retail customers to the competitive market for generation is to be implemented by July 1, 2002. As such, the OCC has until the end of 1999 to submit its final reports. Many significant changes could take place in the intervening period.

Pennsylvania

The Electricity Generation Customer Choice and Competition Act enacted in December 1996 provided a detailed legislative scheme for electricity restructuring in Pennsylvania.[369] This legislation, among other things, allows one-third of Pennsylvania retail customers to choose their electricity suppliers starting January 1, 1999, two-thirds by the year 2000, and all customers by January 1, 2001.

To facilitate this transition to competition, all utilities in the State are required to file restructuring plans with the Pennsylvania Public Utilities Commission (PPUC or the Commission) between April 1, 1997, and September 30, 1997.[370] The utilities must also unbundle their services for transmission, distribution, and generation services.

The legislation establishes procedures and standards for recovery of stranded costs. "Transition or stranded costs" are costs related to supplying electricity that utilities can recover under regulation but may not be recoverable in a competitive generation electric market.[371] Utilities will be given the opportunity to recover these costs subject to legislation that does not guarantee full recovery.

For each utility, the recovery mechanism takes into account the process that led the utility to incur the stranded costs that it claims. Recovery is subject to

[367] Oklahoma State Senate Bill 500, *Electric Restructuring Act of 1997* (April 25, 1997).

[368] Oklahoma Constitutional Article 9, Section 18, OCC Rules 165:35 discusses rules when more than one utility is eligible to service customers in an incorporated town. When a customer in this service area decides to switch electric companies, the new utility must pay exit fees to the old utility. In March 1996, the Oklahoma Supreme Court ruled this practice unconstitutional, setting precedent for the plan to have all customers share in paying for stranded costs through a nonbypassable charge.

[369] Enacted as House Bill 1509, Sections 3-4, Title 66 Pennsylvania Consolidated Statutes, Sections 2801-2812 (December 3, 1996). Section 4 of the House Bill 1509 amends Title 66 by adding a Chapter 28 entitled "Restructuring of the Electric Utility Industry." This is now known as the "Electricity Generation Customer Choice and Competition Act" or the "Customer Choice Act." Note that the legislation was the product of investigations, comment and negotiations involving various stakeholders and the legislators in the State. Refer to Pennsylvania Public Utility Commission, *Report and Recommendation to the Governor and General Assembly on Electric Competition* (July 3, 1996).

[370] Each utility plan, which would be subject to review and approval by the PPUC, would describe how the utility would allow its customers to choose their electricity suppliers.

[371] Title 66 of the Pennsylvania Consolidated Statutes, Section 4, *The Electricity Generation Customer Choice and Competition Act*, Chapter 28: Restructuring of the Electric Utility Industry, Section 2802, p. 4.

mitigation and will be allowed for costs stemming from mandated regulatory actions, including:

- Regulatory assets
- Other deferred charges (like the unfunded portion of a utility's projected nuclear decommissioning costs and cost obligations with nonutility generating projects)
- Prudently incurred costs related to renegotiation of nonutility generation.[372]

Stranded costs resulting from a utility's discretionary actions will be decided by an evidentiary hearing where the Commission will determine the "just and reasonable amount" of recovery. This category includes stranded costs related to a utility's net investments in existing generation plants and facilities, its disposal of spent nuclear fuel, long-term power purchase commitments, retirement costs of existing power plants, and other transition costs.[373]

Aggregate mandated and discretionary stranded costs as determined by the Commission become eligible for recovery provided utilities adopt mitigation strategies to reduce stranded costs.[374] Mitigation strategies recommended for adoption in the legislation include:[375]

- Acceleration of depreciation and amortization of existing rate base generation assets
- Minimization of new capital spending for existing assets
- Reallocation of depreciation reserves
- Reduction of book assets
- Maximization of market revenues from existing ratebase generation assets.

In each case, the Commission will consider the extent to which the utility has taken steps to mitigate stranded costs or to moderate customer rates in the past.

Based on the composition of stranded costs and their determination by the Commission, recovery is proposed through a competitive transition charge (CTC) that each customer accessing the transmission or distribution network pays to the appropriate incumbent distribution company. Allocation of CTC will be designed to prevent cost shifting among customer classes.

Unless otherwise determined by the Commission, CTC recovery may not exceed 9 years after the effective date of the legislation.[376] The legislation caps the customers' total charges at their 1997 levels during the first 54 months of the recovery period (January 1997 to mid-2001) if a utility is still collecting stranded costs via the CTC. After mid-2001, and until the end of 9 years, the cap applies only to the generation portion of the rates. Circumstances allowing the Commission to grant exceptions to these provisions are also stipulated in the legislation. During the time a utility collects the CTC, it continues to be the supplier of last resort.

After the Commission has made its determination of the stranded costs that a utility is entitled to recover, it can issue a qualified rate order authorizing the utility to collect a guaranteed nonbypassable charge called an intangible transition charge (ITC) from every retail customer.[377] This action will permit the utilities to issue (with PPUC approval) transition bonds with a maturity of 10 years or less. Proceeds from the issuance of transition bonds could be used to reduce stranded costs and related capitalization.[378] In addition, the utility could reduce its rates or its CTC to reflect the impact of issuing transition bonds.

While restructuring plans have been submitted by all utilities within the stipulated time period, the Commission has so far acted on a securitization application filed by the PECO Energy Company.[379] In its order

[372] Renegotiation may include cancellation, buyout, or buydown of nonutility generation projects.

[373] Other costs are a catch-all for all costs that a utility may not be able to recover due to transition. The legislation currently provides for transition costs related to employees and costs associated with plants that are no longer used and useful.

[374] The legislation is silent on the methodology to be used by utilities in determining the level of stranded costs each may be allowed to recover.

[375] Each utility plan would be subject to review and approval by the PPUC would describe how the utility would allow its customers to choose their electricity suppliers (Section 2806, p. 51).

[376] The effective date of legislation is January 1, 1997.

[377] The revenue from the ITC will pay principal, interest, and other costs of transition bonds.

[378] The utilities are required to provide information regarding the planned use of proceeds from securitization.

[379] Pennsylvania Public Utility Commission, Opinion and Qualified Rate Order, Docket Nos. R-00973877, R-00973877C0001, and R-00973877C0002 (May 22, 1997). PECO's application for securitization was filed in advance of the final approval of its restructuring plan in January 1997.

issued in May 1997, the Commission concluded that PECO is permitted to securitize an amount of $1.1 billion and that this amount may be recovered from PECO's customers through an intangible transition charge as provided in the legislation.

The above decision was contested, and a consumer advocacy group filed a lawsuit challenging the constitutionality of the electric competition decision, seeking to overturn the May 1997 decision on securitization. In August 1997, PECO reached a negotiated settlement with various interveners in an attempt to end the litigation. The settlement provides consumers with a 10-percent rate reduction and full retail competition for all customers by the year 2000.[380] In addition, PECO would also write off $2 billion in stranded costs, thereby defusing the most contentious issue. In response to this rate reduction, the consumer groups dropped the litigation. Approval by the Commission of the consumer settlement has been complicated by other developments, and the matter was reviewed in December 1997.[381] Larger savings will be realized by consumers in light of the PPUC's December 11, 1997, decision. This revised plan will give consumers up to a 15-percent rate decrease. A revised settlement, approved May 14, 1998, permits PECO to recover $5.26 billion in stranded assets through 2010 and permits securitization of up to $4 billion. Final decisions on remaining restructuring filings are due from the administrative law judge during the first half of 1998.

Rhode Island

Rhode Island was the second State to enact legislation ordering a move from electric utility monopolies to a competitive electric market.[382] *The Utility Restructuring Act of 1996*, enacted August 7, 1996, opens the electric market in Rhode Island for competition. The phase-in schedule is gradual, and by July 1, 1998,[383] all consumers will have access to a competitive electric market.

Stranded costs are defined as "transition costs associated with commitments prudently incurred in the past pursuant to their legal obligations to provide reliable electric service at reasonable costs," according to one of seven findings by the Rhode Island State Legislature. The following transition costs are authorized by the legislation:[384]

- Above-market payments associated with power purchase contracts, plus buyout or buydown payments
- Regulatory assets, including those of fuel suppliers, and obligations for post-retirement health care costs
- Nuclear obligations, including decommissioning costs and costs independent of operation
- Net unrecovered costs of generating plants.[385]

The legislation also gives the Public Utilities Commission (PUC) authority to decide on other specifics, such as the determination of approved transition costs for each utility.

Stranded costs will be recovered through a nonbypassable transition charge paid by all electric customers. An initial transition charge of 2.8 cents per kilowatthour was set for July 1, 1997, through December 31, 2000. Nuclear stranded costs will be accounted for separately. After the year 2000, the transition charges recoverable from customers will be adjusted for any over or under recoveries of the contract termination fees occurring during July 1, 1997, through December 31, 2000. These transition costs can be collected until December 31, 2009. After the initial 3 years have passed, 15 percent of the utilities' generation assets must be sold. The value of the assets as determined by the sale will be used to adjust the stranded investment recovery amount for later years.[386] However, active divestiture beyond the

[380] R. Heidorn,"PECO: Settlement to Include 10 Percent Rate Cut Next Year," *Philadelphia Inquirer* (August 28, 1997).

[381] However, the PPUC is reviewing its May 1997 decision in view of a subsequent counter offer by Enron Corporation, which promises a 20-percent savings for Pennsylvania customers in addition to reimbursing PECO for $5.41 billion in stranded costs.

[382] New Hampshire passed legislation in May 1996. Rhode Island enacted legislation in August 1996.

[383] By July 1, 1997, the following will be able to select nonregulated power producers: all new commercial and industrial customers with an average annual demand greater than 200 kilowatts, all existing manufacturing customers with an average annual demand of 1,500 kilowatts or greater, and all accounts in the name of the State of Rhode Island. Choice is expanded to all customers in Rhode Island "within three months after retail access is available to 40 percent or more of the kilowatt-hour sales in New England." If retail access is not available in New England, then all customers will be able to choose their power producer by July 1, 1998. State of Rhode Island, 96-H 8124 B, *An Act Relating to the Utility Restructuring Act of 1996,* Section 39-1-27.2(a-b) (August 7, 1996).

[384] State of Rhode Island, 96-H 8124 B, *An Act Relating to the Utility Restructuring Act of 1996,* Section 39-1-27.3.

[385] *Ibid.*

[386] Transition cost and recovery information is found in Section 39-1-27.3 of the *Utility Restructuring Act of 1996.*

required 15 percent is encouraged. New England Electric System and Narragansett Electric announced in August 1997 that an affiliate of Pacific Gas and Electric is buying its 18 power plants for $1.59 billion.[387] The Utility Restructuring Act of 1996 required utilities to file their market valuation implementation methodology. Narragansett Electric Company, jointly with the New England Power Company (NEP), filed their proposal with the PUC. Instead of simply finding methods to evaluate stranded costs, they decided to sell all of their non-nuclear generation assets. This approach was approved by the PUC, which will now monitor the process of divestiture as the transition period continues.[388] The State Assembly also passed a securitization bill on June 27, 1997, allowing utilities to finance "contract termination fees" through transition bonds.[389]

Vermont

The Vermont Public Service Board (PSB or the Board) organized a working group to study electric industry restructuring in December 1994. Two years later, on December 31, 1996, a final regulatory order was completed, opening Vermont's electric market to competition. Since many key features of this plan could only be accomplished with legislative action, the State Senate introduced S. 62, *An Act Relating to Electric Industry Restructuring and Electric Price Stabilization.* The Act passed the Senate in March 1997, but stalled in the House. It is expected that the legislation will be revisited in the 1998 session.

The Board's plan evolved after 2 years of meetings, workshops, and conferences involving utility managers, business leaders, consumer advocates, government officials, and other technical experts. The final order contains nine restructuring principles, one of which is to "provide equitable treatment of stranded costs."[390] Stranded costs are defined "as the value of existing regulated utility assets that are in excess of their fair market value."[391] The stranded cost subcommittee developed a State-wide analysis of the level of stranded costs. The preliminary figures ranged from $352 million to $1.4 billion, depending on the market price of electricity. Approximately 60 percent of the stranded costs are the result of purchase power contracts.[392] The order promotes various mitigating actions, such as innovative financing, renegotiation of above-market contractual commitments, and asset sales. According to the order, "companies that succeed in mitigating a significant portion of their current, legitimate above-market costs and that can commit to competitive prices will have the greatest likelihood of recovering their total remaining stranded cost exposure."[393]

The order calls for a three-step plan to guide the transition period, with stranded cost recovery to be completed no later than December 31, 2001. The first step is to estimate stranded costs for each utility, using a "bottom-up" approach. Utilities must submit their stranded cost estimates, and "each claim for recovery of stranded costs will be balanced against the potential to mitigate those costs."[394] Step two, the adjusting of stranded cost estimates, will begin once the market is open to competition. In this phase, the initial administrative estimates of stranded costs will be adjusted for other factors, including mitigation efforts (such as the sale of generation assets) and electricity prices. By the start of 2001, a final valuation of stranded costs will be completed.

A nonbypassable competitive transition charge (CTC) will be collected from all retail customers in Vermont to pay for the recovery of identified stranded costs. Securitization is under consideration, with the report and order concluding "we believe that a substantial portion of the final stranded cost recovery amount can be financed through specially-authorized utility revenue bonds, secured through the assignment of CTC receipts."[395]

The Board's plans now await further action of the legislature to begin full implementation of this plan. A committee of the Vermont House of Representatives voted against crafting retail competition legislation in

[387] New England Electric System Press Release, "New England Electric System Sells Generating Business to PG&E Corporation's U.S. Generating Company" (August 6, 1997).

[388] Public Utilities Commission, *In RE: Narragansett Electric Company and New England Power Company-Market Valuation Implementation Methodology,* Docket 2540 (May 2, 1997).

[389] H. 7003, *An Act Relating to Public Utility Securitization* (June 27, 1997).

[390] State of Vermont Public Service Board Final Report and Order, Docket 5854 (December 31, 1996), p. 11.

[391] *Ibid.*, p. 51.

[392] *Ibid.*, p. 53.

[393] *Ibid.*, p. 12.

[394] *Ibid.*, p. 80.

[395] *Ibid.*, p. 87.

October 1997. The legislature, did, however call for a bill to be developed for performance-based ratemaking.

Virginia

A roadmap for restructuring Virginia's electric power industry was set in place through the enactment of *An Act to Establish a Schedule for Virginia's Transition to Retail Competition in the Electric Utility Industry.* This legislation is effective July 1, 1998, and it opens Virginia's electric market to competition beginning January 1, 2002. By January 1, 2004, the transition to full competition will be complete. This roadmap does not provide all details on how this transition will take place, but future legislation by the Virginia Assembly and Orders from the State Corporation Commission (SCC) will ensure the details leading to competition are in place.

Just and reasonable net stranded costs will be recoverable and appropriate consumer safeguards related to stranded costs will be implemented. Estimates of stranded costs, recovery mechanisms, mitigation strategies and other stranded cost related issues still need to be determined.

Appendix F

Electricity Restructuring Bills Introduced in the 105th Congress as of May 31, 1998

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House Bills

H.R. 338
Ratepayer Protection Act
Introduced on January 7, 1997, by Representative Clifford Stearns (R-FL).

- Mandates that the Public Utility Regulatory Policies Act of 1978 (PURPA) Section 210 requirement that electric utilities enter into contracts to purchase electricity from certain "qualified" cogeneration and small power production facilities shall expire after January 7, 1997, so that no such utility shall be required to enter into any such contract after that date.

- Mandates that Section 210 contracts which were in effect up to January 7, 1997, shall 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 prior to January 7, 1997.

H.R. 655
Electric Consumers' Power to Choose Act of 1997
Introduced on February 10, 1997, by Representative Daniel Schaefer (R-CO).

- Sets December 15, 2000, as the deadline by which all electric utility retail customers will have the right to purchase retail electric energy services from a supplier of their choice. Protects prior State actions in promoting retail choice, if such actions meet certain criteria.

- States may elect, within 6 months of enactment of this statute, to implement retail electric service choice, to be structured and implemented in accordance with the requirements of this statute, by December 15, 2000. FERC shall implement such retail competition in any State that does not make this election. Requirements for such retail service include customer right to choose among providers, provider access to local distribution facilities on a "comparable" basis, flexible pricing and incentive-based rate regulation, prohibition of cross-subsidies from noncompetitive services, cessation of traditional rate regulation upon establishment of competition, and consideration of reliability, stranded costs, efficiency, conservation, and environmental concerns.

- Provides continued customer protection guarantees.

- Permits nonregulated utilities to adopt retail electric service competition.

- Clarifies FERC's authority to require transmission operators to provide transmission services under terms and conditions comparable to those under which the transmission utility uses its own system.

- Mandates minimum renewable portfolio requirements (2 percent by 2001, 3 percent by 2005, and 4 percent by 2010).

- Repeals Public Utility Holding Company Act of 1935 (PUHCA) application and PURPA mandatory purchase obligations in States in which retail competition is established.

- Requires providers of retail transmission or distribution to obtain FERC determinations as to which of their facilities are FERC jurisdictional and which are State jurisdictional.

- Directs States to consider as a part of their election to retail service choice whether to allow recovery of stranded costs.

H.R. 1230
Consumers Electric Power Act of 1997
Introduced by Representative Thomas DeLay (R-TX) on April 8, 1997.

- Guarantees all retail customers the right to choose their electric supplier by January 1, 1999.

- Retains State and local government authority concerning their obligation to connect customers to the local distribution system and to ensure its maintenance, reliability, and safety. States also retain authority to provide for the continuation of universal service and programs covering conservation, renewables, research and development, and other matters.

- Mandates that vertically integrated utilities maintain "organizational separation" between transmission and distribution operation and provision of service.

- Empowers FERC to regulate distribution access and services, but directs FERC to defer to States in regard to certain distribution-related matters.

- Mandates that transmission and distribution be operated in such fashion as to assure access to information.

- Prohibits Federal Government and States from granting any "preference" or "protection from competition" to any electric service provider, including subsidies and exit fees.

- Renders PURPA Section 210 and PUHCA inapplicable where competition is present.

- Empowers FERC to take steps ensuring that utilities do not exercise market power.

- Empowers FERC to impose nondiscriminatory access to transmission and distribution by eliminating "barriers to competition" imposed by "existing contracts and arrangements."

- Prohibits changes in providers without customers' approval.

- Mandates that States assign customers who fail to choose service providers to "one of a variety of . . . providers" on a nondiscriminatory basis.

H.R. 1359
To Amend the Public Utility Regulatory Policies Act of 1978 to Establish a Means to Support Programs for Electric Energy Conservation and Energy Efficiency, Renewable Energy, and Universal and Affordable Service for Electric Consumers
Introduced April 17, 1997, by Representative Peter DeFazio (D-OR).

- Amends PURPA to establish a National Electric System Public Benefits Fund to provide matching funds to States for supporting eligible public purpose programs like conservation and energy efficiency and renewable energy, universal and affordable service, or research and development.

- Creates a National Electric System Public Benefits Board to manage the Fund, with oversight responsibilities entrusted to the Secretary of Energy.

- Requires each electric power generation facility owner or operator, as a condition of transmitting power to any transmitting utility, to contribute funds (based on kilowatthours transmitted and not exceeding 2 mills per kilowatthour) necessary to generate half of required revenues.

- Authorizes States to create additional public purpose programs and seek matching funds.

H.R. 1960
The Electric Power Competition and Consumer Choice Act of 1997
Introduced on June 19, 1997, by Representative Edward Markey (D-MA).

- Requires each State to initiate retail competition rulemaking proceedings.

- Declares PUHCA inapplicable to holding company systems which are in compliance with certain specific standards and requirements of competition and public benefits programs under PURPA.

- Exempts utilities which obtain certification of competition from PURPA requirement to purchase electricity from qualified cogenerators and small power production facilities.

- Sets limits upon use of customer information by utilities.

- Amends PURPA by authorizing States to include incremental environmental costs in their avoided cost computations.

- Mandates that the Securities and Exchange Commission (SEC) may not exempt acquisition by a registered holding company of energy-related entities from prior approval, and that the SEC may not permit a registered holding company to invest in foreign utility operations in excess of 50 percent of consolidated retail earnings, except with a certification of competition.

- Prohibits utilities which have exclusive service territories from offering any services outside their territories unless such services are also available, on comparable terms, to customers within their territories.

- Directs FERC to establish parameters governing mergers, acquisitions, market concentration, and affiliate relationships and diversification.

- Authorizes FERC to remove situations which are "inconsistent with effective competition."

- Amends the Federal Power Act of 1935 (FPA) by directing FERC to promulgate rules establishing tariffs to ensure development of competitive electricity markets, ensure full recovery of prudent transmission costs, prevent multiple transmission charges, and prevent electricity sellers from gaining advantage over competitors by reason of ownership or control of facilities.

- Renders FERC open access transmission rules applicable to non-public utilities, including Power Marketing Administrations (PMAs).

- Requires each electric utility and transmitting utility to become a member of a self-regulated regional reliability council overseen by FERC.

- Requires the Federal Trade Commission (FTC) to regulate disclosure of information to consumers, to assist them in making informed choices regarding utility services.

- Requires FERC to prescribe rules to assure that no electric provider may gain "any competitive advantage" by reason of ownership of facilities that are not subject to certain emissions limitations.

- Promotes renewables by creating a renewable energy trading system managed by the Department of Energy (DOE) that requires all electricity generators to submit renewable energy credits increasing from 3 percent to 10 percent of total sales by the year 2010.

- Creates a Federal-State Joint Board to recommend universal service support mechanisms.

H.R. 2909

To Amend the Federal Power Act To Establish Requirements Regarding the Operation of Certain Electric Generating Facilities, and for Other Purposes

Introduced November 7, 1997, by Representative Frank Pallone, Jr. (D-NJ).

- 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 standard for oxides of nitrogen and 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 oxides of nitrogen 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 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."

H.R. 3548
Environmental Priorities Act of 1998
Introduced March 25, 1998, by Representative Robert E. Andrews (D-NJ).

- Establishes a Fund for Environmental Priorities to be funded by a portion of savings resulting from retail electricity choice, and for other purposes.

- Proposes establishing a "National Environmental Priorities Board," to create and administer various programs relating to environmental issues. Such programs may include direct loans, loan guarantees, enhancing river buffer zones, mitigating deleterious effects of electricity production on air quality, and supporting the preservation of open space.

- Calls for 10 percent of "consumer savings" under competition to be contributed to the "Environmental Priorities Board."

- Sets out a methodology for derivation of "consumer savings."

- Provides a start date for each State based on establishment of retail electric service, but not earlier than January 1, 2001.

H.R. 3927
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 May 21, 1998, by Representative Phil English (R-PA).

- 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 a limited area.

H.R. 3976
A Bill to Repeal the Public Utility Holding Company Act of 1935, to Enact the Public Utility Holding Act of 1998, and for Other Purposes
Introduced May 22, 1998, by W.J. (Billy) Tauzin (R-LA).

- Repeals the Public Utility Holding Company Act of 1935.

- Enacts the Public Utility Holding Company Act of 1998 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.

Senate Bills

S. 237
Electric Consumers Protection Act of 1997
Introduced by Senator Dale Bumpers (D-AR) on January 30, 1997.

- Mandates that, as of December 15, 2003, all customers shall have the right to buy retail electricity from any provider, and all providers shall have nondiscriminatory access to local distribution and retail transmission facilities. States may start the program earlier, and State legislation enacted prior to January 30, 1997, is grandfathered.

- Sets forth guidelines for (1) States' regulatory authority, (2) recovery of stranded costs by a retail electric energy provider or by a multi-State utility company, (3) universal service for customers unable to seek alternative suppliers, and (4) funding public benefits programs.

- Mandates that energy providers meet a portion of load via renewable resources. Required annual percentage starts at 5 percent in 2003 and rises to 12 percent by 2013.

- Directs FERC to establish transmission regions and to designate an independent system operator to manage and operate each region's system. If all States in a region join together to form a Regional Transmission Oversight Board, the Board shall have significant powers regarding rates, service, and transmission access.

- Amends FPA to prohibit electric utilities from acquiring facilities or securities of natural gas utilities.

- Mandates recovery of nuclear decommissioning costs from customers.

- Sets out various measures which together permit competition by and with the Tennessee Valley Authority (TVA).

- Repeals PUHCA one year after enactment while retaining certain of PUHCA's regulatory provisions.

- Permits aggregators to purchase retail electric energy.

- Repeals FPA Section 212(h) prohibition against FERC ordering retail wheeling in cases involving States that have authorized retail electric competition prior to December 15, 2003, and in all cases thereafter.

- Prospectively repeals PURPA provisions mandating that utilities purchase power from qualified cogenerators and small power producers.

- Instructs the Environmental Protection Agency (EPA) to report on the implications of differences in air pollution emission standards related to wholesale and retail electric competition, and their impacts on public health and the environment.

- Mandates procedures for determination and recovery of stranded costs related to "regional" generation facilities.

- Directs FERC to order various actions including physical connections of transmission facilities and divestiture of generation and transmission facilities to prevent any electric supplier from maintaining "a situation inconsistent with effective competition."

S. 621
Public Utility Holding Company Act of 1997
Introduced by Senator Alfonse D'Amato (R-NY) on April 22, 1997.

- Repeals PUHCA.

- Prescribes procedural guidelines for FERC and States to access records of public utility holding companies.

- Retains FERC and States' jurisdiction to determine whether electric or natural gas utilities may recover in rates any costs of affiliate transactions or affiliate activities.

- Grants FERC certain enforcement powers.

S. 687
Electric System Public Benefits Protection Act of 1997
Introduced by Senator James Jeffords (R-VT) on May 1, 1997.

- Directs the Secretary of Energy to establish a National Electric System Public Benefits Board to administer a fund to provide matching monies to States supporting renewable energy sources, universal electric service, energy conservation, and other public purposes.

- Prescribes funding for the Board via a nonbypassable wires charge of up to 2 mills per kilowatthour.

- Establishes minimum requirements for electricity generation from renewable sources as a portion of total electric sales, increasing gradually from 2.5 percent in 2000 to 20 percent in 2020.

- Requires FERC to issue renewable energy credits covering electricity produced from renewable sources.

- Repeals PURPA cogeneration and small power production provisions.

- Requires the EPA to promulgate nationwide emission standards (for generating facilities) for nitrogen oxide, sulfur dioxide, and carbon dioxide for the year 2005 and each year thereafter, sets out minimum standards, and entrusts the EPA with monitoring of compliance and issuance of emissions credits.

- Directs the DOE to establish disclosure requirements that enable customers to knowledgeably compare retail electric service offerings, based on generation and emissions data, price terms, and other factors, and sets penalties for nondisclosure.

S. 722
Electric Utility Restructuring Empowerment and Competitiveness Act of 1997
Introduced on May 8, 1997, by Senator Craig Thomas (R-WY).

- Amends the FPA to provide States with significant new powers to promote retail competition.

- Mandates wholesale and retail transmission reciprocity.

- Demarcates States' authority to establish and enforce reliability standards, promote renewable energy resources, recover stranded costs, encourage environmental programs, and support public benefit programs including assistance to low-income families.

- Reinforces States' authority to require electricity retailers to assist in providing universal service.

- Enlarges States' authority over wholesale sales by removing it from FERC's purview while retaining their authority over retail electric energy sales.

- Exempts sales of electric energy for resale from traditional FERC regulation.

- Instructs the Department of Treasury to report on the impact of specified tax provisions to foster a competitive retail electricity market.

- Repeals PURPA Section 210 requirement that utilities purchase power from qualified cogenerators and small power producers.

- Repeals PUHCA but retains certain PUHCA regulatory provisions.

S. 1276
The Federal Power Act Amendments of 1997
Introduced by Senator Jeff Bingaman (D-NM) on October 8, 1997.

- Clarifies FERC jurisdiction over regulation of transmission and distribution.

- Places transmission systems of Federal power marketing agencies (including TVA), municipal utilities, and rural electric cooperatives under FERC's jurisdiction.

- Limits FERC's authority to order retail wheeling unless permitted or required by State law.

- Clarifies States' authority to require retail competition and unbundled local distribution service, and to require nondiscriminatory service or reciprocity in implementing competition.

- Instructs FERC to establish and enforce transmission reliability standards.

- Broadens FERC authority to order a transmitting utility to enlarge, extend, or improve its transmission facilities.

- Authorizes FERC to designate a national electric reliability council and regional reliability councils, which must meet certain requirements.

- Provides protection of existing PURPA Section 210 power purchase contracts by precluding nonrecovery of related costs.

- Authorizes FERC to order formation of regional transmission systems and appoint an oversight board to oversee such systems. This board shall appoint independent system operators to operate these systems.

S. 1401 [396]
Transition to Electric Competition Act of 1997
Jointly introduced by Senators Dale Bumpers (D-AR) and Slade Gorton (R-WA) on November 7, 1997.

- Mandates that, as of January 1, 2002, all consumers shall have the right to buy retail electricity from any provider, and all providers shall have nondiscriminatory access to local distribution and retail transmission facilities.

- Mandates that electricity providers meet a portion of load via renewable resources (5 percent in 2003, increasing to 12 percent in 2013).

[396] This legislation is a revision of previous legislation (S. 237) introduced by Sen. Bumpers in January 1997.

- Sets forth a FERC procedure to determine whether any particular electric energy transportation facility is Federal or State jurisdictional.

- Directs FERC to develop transmission regions and designate an independent system operator to manage and operate each region's system.

- Permits recovery of nuclear decommissioning costs via nonbypassable charges levied upon certain defined customer groups.

- Mandates State procedures for determination of retail stranded costs and provides right to recovery of all such stranded costs over a reasonable period of time, by means of a nonbypassable charge.

- Sets out various measures which together permit competition by TVA and with TVA.

- Repeals PUHCA one year after the date of the enactment but retains certain of PUHCA's regulatory provisions.

- Prospectively repeals PURPA Section 210 regarding mandatory power purchases from cogenerators and small power producers.

- Instructs EPA to report differences in air pollution emissions related to competition and their impacts on public health and the environment.

- Places transmission services of Bonneville Power Administration (BPA) under FERC's nondiscriminatory open access rules, and permits BPA to join an independent system operator.

- Directs FERC to order various actions including physical connection of transmission facilities and divestiture of generation and transmission facilities to prevent any electric supplier from maintaining "a situation inconsistent with effective competition."

- Mandates procedures for determination and recovery of stranded costs related to "regional" generation facilities.

S. 1483
To Amend the Internal Revenue Code of 1986 To Provide for the Treatment of Tax-Exempt Bond Financing of Certain Electrical Output Facilities
Introduced by Senator Frank Murkowski (R-AK) on November 8, 1997.

- Amends tax laws to permit municipal utilities to participate in open access plans without forfeiting the tax-exempt status of their current bonds.

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