906TH—MEETING—Continued

Item No.	Docket No.	Company
	Gas	
G–1	PL04–3–000	Natural Gas Interchangeability.
G–2	RM06–17–000	Natural Gas Supply Association.
G–3	RP05–618–002	Colorado Interstate Gas Company.
G–4	OMITTED.	
G–5	TS04–280–002	Jupiter Energy Corporation.
	TS05–10–000	Cotton Valley Compression, L.L.C.
	TS05–3–000	Texas Eastern Transmission, LP.
	TS05–19–000	Chandeleur Pipe Line Company.
	TS05–21–000	Sabine Pipe Line Company.
	TS05–17–000, OA05–1–000	Thumb Electric Cooperative.
	TS05–15–000	Discovery Gas Transmission Inc.
	Hydro	
H–1	P–12641–000	Mt. Hope Waterpower Project LLP.
H–2	P–4244–021	Northumberland Hydro Partners, L.P.
	P–10648–009	Adirondack Hydro Development Corporation.
H–3	P–12451–003	SAF Hydroelectric, LLC.
H–4	P–12462–003	Indian River Power Supply, LLC.
	P–12430–002	Alternative Light and Hydro Associates.
H–5	P–2118–011	Pacific Gas and Electric Company.
H–6	P–1962–136	Pacific Gas and Electric Company.
	Certificates	
C–1	RM06–12–000	Regulations for Filing Applications for Permits to Site Transmission Facilities.
C–2	RM05–23–000, AD04–11–000	Rate Regulation of Certain Natural Gas Storage Facilities.
C–3	RM06–7–000	Revisions to the Blanket Certificate Regulations and Clarification Regarding Rates.
C–4	CP05–130–000, CP05–130–001, CP05–130–002	Dominion Cove Point LNG, LP.
	CP05–132–000, CP05–132–001	Dominion Cove Point LNG, LP.
	CP05–131–000, CP05–131–001	Dominion Transmission, Inc.
C–5	CP05–360–000	Creole Trail LNG, L.P.
	CP05–357–000, CP05–357–001, CP05–357–002, CP05–358–000, CP05–359–000.	Cheniere Creole Trail Pipeline, L.P.
C–6	CP05–396–000	Sabine Pass LNG, L.P.
C–7	CP04–411–000	Crown Landing LLC.
	CP04–416–000	Texas Eastern Transmission, LP.
C–8	CP05–83–000	Port Arthur LNG, L.P.
	CP05–84–000, CP05–84–001, CP05–85–000, CP05–86–000.	Port Arthur Pipeline, L.P.
C–9	CP05–395–000	Dominion Cove Point LNG, LP.
C–10	CP06–26–000	Dominion Cove Point LNG, LP.
C–11	OMITTED.	

Magalie R. Salas,
Secretary.

A free webcast of this event is available through *www.ferc.gov.* Anyone with Internet access who desires to view this event can do so by navigating to *www.ferc.gov's* Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit *www.CapitolConnection.org* or contact Danelle Perkowski or David Reininger at 703–993–3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in Hearing Room 2. Members of the public may view this briefing in the Commission Meeting overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

[FR Doc. 06–5415 Filed 6–9–06; 3:54 pm]

BILLING CODE 6717–01–U

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD05–17–000]

Electric Energy Market Competition Task Force; Notice Requesting Comments on Draft Report to Congress on Competition in the Wholesale and Retail Markets for Electric Energy

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice.

SUMMARY: Section 1815 of the Energy Policy Act of 2005 requires the Electric Energy Market Competition Task Force

to conduct a study and analysis of competition within the wholesale and retail market for electric energy in the United States and to submit a report to Congress within one year. Section 1815 further requires that the Task Force publish its draft report in the **Federal Register** for public comment 60 days prior to submitting its final report to the Congress. The Federal Energy Regulatory Commission, as an agency with a representative on the Task Force, is publishing this notice providing the draft report and seeking public comment on behalf of the Task Force.

DATES: Comments are due on or before 5 p.m. Eastern Time June 26, 2006.

ADDRESSES: Comments may be electronically filed by any interested person via the e-Filing link on the Federal Energy Regulatory Commission's Web site at *http://www.ferc.gov* for Docket No. AD05–17–000. Persons filing electronically do not need to make a paper filing. Persons that are not able to file electronically must send an original of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT: Moon Paul, Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. 202–502–6136.

SUPPLEMENTARY INFORMATION: Section 1815 of the Energy Policy Act of 2005 established an interagency task force to conduct a study and analysis of competition within the wholesale markets and retail markets for electric energy in the United States. The task force has 5 members: (1) An employee of the Department of Justice, appointed by the Attorney General of the United States; (2) an employee of the Federal Energy Regulatory Commission, appointed by the Chairperson of that Commission; (3) an employee of the Federal Trade Commission, appointed by the Chairperson of that Commission; (4) an employee of the Department of Energy, appointed by the Secretary of Energy; and (5) an employee of the Rural Utilities Service, appointed by the Secretary of Agriculture.

The Electric Energy Market Competition Task Force consulted with and solicited comments from the States, representatives of the electric power industry and the public, in accordance with a notice requesting public comment published in the **Federal Register** on October 19, 2005 at 70 FR 60819. A full listing of the persons or entities that have met with the task force or submitted comments in response to the notice will be listed as an attachment to the final report.

The draft report of the Electric Energy Market Competition Task Force is attached to this notice as Appendix A. The appendices to the draft report will not be published in the **Federal Register**, but will be available online, as follows. The draft report is also available at each of the following Web sites of the Task Force members' agencies:

Department of Justice: *http://www.usdoj.gov/atr*

Federal Energy Regulatory Commission: *http://www.ferc.gov/legal/staff-reports/epact-competition.pdf*

Federal Trade Commission: *http://www.ftc.gov*

Department of Energy: *http://www.oe.energy.gov*

Department of Agriculture: *http://www.usda.gov/rus/electric/competition/index.htm*

Members of the public are invited to comment on the draft report and encouraged to file comments as soon as is practicable in order to maximize the time available to the task force to consider these comments. Comments will be received by the Federal Energy Regulatory Commission and available for public review. A final report will be delivered to Congress on or before August 8, 2006 in accordance with the statutory deadline.

How To File Comments

Any interested person may submit a written comment and it will be made part of the public record of the Task Force maintained with the Federal Energy Regulatory Commission. Comments may be filed electronically via the e-Filing link on the Federal Energy Regulatory Commission's Web site at *http://www.ferc.gov* for Docket No. AD05–17–000.

Most standard word processing formats are accepted, and the e-Filing link provides instructions for how to Login and complete an electronic filing. First-time users will have to establish a user name and password. User assistance for electronic filing is available at 202–208–0258 or by e-mail to efiling at ferc.gov. Comments should not be submitted to the e-mail address. Persons filing comments electronically do not need to make a paper filing. Persons that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov*, using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov*, or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: June 5, 2006.

Magalie R. Salas,

Secretary, Federal Energy Regulatory Commission.

Appendix A—Draft Report of the Electric Energy Market Competition Task Force

Report to Congress on Competition in the Wholesale and Retail Markets for ELectric Energy

Draft

June 5, 2006.

By The Electric Energy Market Competition Task Force.

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Executive Summary

Congressional Request

Section 1815 of the Energy Policy Act of 2005 (the Act) requires the Electric Energy Market Competition Task Force (Task Force) to conduct a study of competition in wholesale and retail markets for electric energy in the United States.[1] Section 1815(b)(2)(B) of the Act requires the Task Force to publish a draft final report for public comment 60 days prior to submitting the final version to Congress. This **Federal Register** notice fulfills this statutory obligation. The Task Force seeks comment on the preliminary observations contained in this draft report.

Task Force Activities

In preparing this report, the Task Force undertook several activities, as follows:

- Section 1815(c) of the Energy Policy Act of 2005 required the Task Force to ''consult with and solicit comments from any advisory entity of the task force, the States, representatives of the electric power industry, and the public.'' Accordingly, the Task Force published a **Federal Register** notice seeking comment on a variety of issues related to competition in wholesale and retail electric power markets to comply with this statutory obligation. The Task Force received over 80 comments that expressed a variety of opinions and analyses. The list of parties who submitted comments is attached as Appendix A.
- The Task Force met and discussed competition-related issues with a variety of representatives of the electric power industry in October/November 2005. These groups are listed in Appendix B.
- The Task Force prepared an annotated bibliography of the public cost/benefit studies that have attempted to analyze the status of wholesale and retail competition. Appendix C contains this bibliography.
- The Task Force researched and analyzed the relevant features of seven states that have implemented retail competition. The states include: Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas. These seven states represent the various approaches that states have used to introduce retail competition where retail competition programs are active. Appendix D contains these individual state profiles.
- The Task Force reviewed the information gleaned from comments, interviews, and further research. They then produced draft documentation of the resulting observations and findings. These drafts were circulated among task force members for comments and revised. No outside contractors were hired to conduct this work.

Federal and several state policymakers generally introduced competition in the electric power industry to overcome the perceived shortcomings of traditional cost-based regulation. In competitive markets, prices are expected to guide consumption and investment decisions to bring about an efficient allocation of resources.

Observations on Competition in Wholesale Electric Power Markets

For almost 30 years, Congress has taken steps to encourage competition in wholesale electric power markets. The Public Utility Regulatory Policies Act of 1978, the Energy Policy Act of 1992, and the Energy Policy Act of 2005 all sought to promote competition by lowering entry barriers, increasing transmission access, or both. Federal electricity policies seek to strengthen competition but continue to rely on a combination of competition and regulation.

In responding to its statutory charge, the Task Force has sought to answer the following question:

> Has competition in wholesale markets for electricity resulted in sufficient generation supply and transmission to provide wholesale customers with the kind of choice that is generally associated with competitive markets?

To answer this question, the Task Force examined whether competition has elicited consumption and investment decisions that were expected to occur with wholesale market competition.

The Task Force found this question challenging to address. Regional wholesale electric power markets have developed differently since the beginning of widespread wholesale competition. Each region was at a different regulatory and structural starting point upon Congress' enactment of the Energy Policy Act of 1992. Some regions already had tight power pools, others were more disparate in their operation of generation and transmission. Some regions had higher population densities and thus more tightly configured transmission networks than did others. Some regions had access to fuel sources that were unavailable or less available in other regions (e.g., natural gas supply in the Southeast, hydro-power in the Northwest). Some regions operate under a transmission open-access regime that has not changed since the early days of open access in 1996, while other regions have independent provision of transmission services and organized day-ahead exchange markets for electric power and ancillary services. These differences make it difficult to single out the determinants of consumption and investment decisions and thus make it difficult to evaluate the degree to which more competitive markets have influenced such decisions. Even the organized exchange markets have different features and characteristics.

Despite the difficulty of directly answering the question at hand, the Task Force's examination of wholesale competition has yielded some useful observations, as presented below. The Task Force seeks comment on these observations.

Observations on Competitive Market Structures

1. One approach to competition in wholesale markets is to base trades exclusively on bilateral sales directly negotiated between suppliers, rather than on a centralized trading and market clearing mechanisms. This approach predominates in the Northwest and Southeast. This bilateral format allows for somewhat independent operation of transmission control areas and, in the view of some market participants, better accommodates traditional bilateral contracts. However, the fact that prices and terms can be unique to each transaction and are not always publicly available can lead to less than efficient (not least cost) generation dispatch

[1] The Task Force consists of 5 members: (1) One employee of the Department of Justice, appointed by the Attorney General of the United States; (2) one employee of the Federal Energy Regulatory Commission, appointed by the Chairperson of that Commission; (3) one employee of the Federal Trade Commission, appointed by the Chairperson of that Commission; (4) one employee of the Department of Energy, appointed by the Secretary of Energy; (5) one employee of the Rural Utilities Service (RUS), appointed by the Secretary of Agriculture.

scenarios. Also, it can be difficult to efficiently coordinate transmission when using this trading mechanism. The lack of centralized information about trades leaves the transmission owner with system security risks that necessitate constrained transmission capacity. In some of these markets, wholesale customers have difficulty gaining unqualified access to the transmission they would need to access competitively priced generation—thus limiting their ability to shop for least cost supply options.

2. Another approach to wholesale competition relies on entities which are independent of market participants to operate centralized regional transmission facilities and trading markets (Regional Transmission Organizations or Independent System Operators). Various forms of this approach have come to predominate in the Northeast, Midwest, Texas, and California. The market designs in these regions provide participants with guaranteed physical access to the transmission system (subject to transmission security constraints). These customers are responsible for the cost of that access (if they choose to participate), and thus are exposed to congestion price risks. This more open access to transmission can increase competitive options for wholesale customers and suppliers as compared to most bilateral markets. The transparency of prices in these markets can increase the efficiency of the trading process for sellers and buyers and can give clear price signals indicating the best place and time to build new generation. However, concerns have been raised about the inability to obtain long-term transmission access at predictable prices in these markets and the impact that this lack of long-term transmission can have on incentives to construct new generation. Some customers have raised concerns about high commodity price levels in these markets.

Observations on Generation Supply in Markets for Electricity

Several options may be used to elicit adequate supply in wholesale markets:

1. One possible, but controversial, way to spur entry is to allow wholesale price spikes to occur when supply is short. The profits realized during these price spikes can provide incentives for generators to invest in new capacity. However, if wholesale customers have not hedged (or cannot hedge) against price spikes, then these spikes can lead to adverse customer reactions. Unfortunately, it can be difficult to distinguish high prices due to the exercise of market power from those due to genuine scarcity. Customers exposed to a price spike often assume that the spike is evidence of market abuse. Past price spikes have caused regulators and various wholesale market operators to adopt price caps in certain markets. Although price caps may limit price spikes and some forms of market manipulation, they can also limit legitimate scarcity pricing and impede incentives to build generation in the face of scarcity. Not all the caps in place may be necessary or set at appropriate levels.

2. ''Capacity payments'' also can help elicit new supply. Wholesale customers make these payments to suppliers to assure the availability of generation when needed. However, where there are capacity payments in organized wholesale markets, it is difficult for regulators to determine the appropriate level of capacity payments to spur entry without over-taxing market participants and customers. Also, capacity payments may elicit new generation when transmission or other responses to price changes might be more affordable and equally effective. Depending on their format, capacity payments also may discourage entry by paying uneconomical generation to continue running when market conditions otherwise would have led to the closure of that generation.

3. Building appropriate transmission facilities may encourage entry of new generation or more efficient use of existing generation. But, transmission owners may resist building transmission facilities if they also own generation and if the proposed upgrades would increase competition in their sheltered markets. Another challenge with transmission construction is that it is often difficult to assess the beneficiaries of transmission upgrades and, thus, it is difficult to identify who should pay for the upgrades. This challenge may cause uncertainty both for new generators and for transmission owners. There can also be difficulties associated with uncertain revenue recovery due to unpredictable regulatory allowances for rate recovery.

4. Another option for ensuring adequate generation supply is through traditional regulatory mechanisms—regulatory control over electricity generators/suppliers. In this situation, Monopoly utility providers operate under an obligation to plan and secure adequate generation to meet the needs of their customers. Regulators allow the utilities to earn a fair rate of return on their investment, thereby encouraging utility investment. However, this approach is not without risk to the utility as regulators have authority to disallow excessive costs. Furthermore, these traditional methods are imperfect and can in some cases lead to overinvestment, underinvestment, excessive spending and unnecessarily high costs. These methods can distort both investment and consumption decisions. Furthermore, under traditional regulation, ratepayers (rather than investors) may bear the risk of potential investment mistakes.

Observations on Competition in Retail Electric Power Markets

The Task Force examined the implementation of retail competition in seven states in detail: Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas. The implementation of retail competition raises the question whether retail prices are higher or lower than they otherwise would be absent the introduction of this competition.

In most profiled states, retail competition began in the late 1990s. States implemented retail rate caps and distribution utility obligations to serve, which are now just ending, that make it difficult to judge the success or failure of retail competition. Few alternative suppliers currently serve residential customers, although industrial customers have additional choices. To the extent that multiple suppliers serve retail customers, prices have not decreased as expected, and the range of new options and services is limited. Since retail competition began, most distribution utilities in the profiled states have either sold most of their generation assets or transferred them to unregulated affiliates.

One of the main impediments to retail competition has been the lack of entry by alternative suppliers and marketers to serve retail customers. Most states required the distribution utility to offer customers electricity at a regulated price as a backstop or default if the customer did not choose an alternative electricity supplier or the chosen supplier went out of business—this is called ''provider of last resort (POLR) service.'' Many of these states capped the POLR service price for ''transitional'' multi-year periods that are now just ending. These caps have had the unintended effect of discouraging entry by competitive suppliers. Thus, it has been difficult for the Task Force to determine whether retail prices in the profiled states are higher or lower than they otherwise would be absent the introduction of retail competition. At the same time, there is some evidence that alternative suppliers have offered new retail products including ''green'' products that are more environmentally friendly

for residential and non-residential customers and customized energy management products for large commercial and industrial customers.

When the rate caps expire, states must decide whether to continue POLR for all customer classes and how to price POLR service for each class. Several states have rate caps that will expire in 2006 and 2007. The Task Force seeks comment on the observations about how POLR prices affect competition in retail electric power markets.

1. If regulators intend for the POLR service to be a proxy for efficient price signals, it must closely approximate a competitive price. The competitive price is based on supply and demand at any given time. If the POLR service price does not closely match the competitive price, it is likely to distort consumption and investment decisions.[2]

2. If POLR prices remain fixed while prices for fuel and wholesale power are rising, customers may experience rate shock when the transition period ends. This rate shock can create public pressure to continue the fixed POLR rates at below-market levels. One regulatory response may be to phase in the price increase gradually, by deferring recovery of part of the supplier's costs. Although this approach reduces rate shock for customers, it is likely to distort retail electricity markets both in the short-term (when costs are deferred) and in the long-term (when the deferred costs are recovered).

3. Some states have different POLR service designs for different customer classes. POLR prices for large commercial and industrial customers have reflected wholesale spot market prices more than have POLR prices for residential customers. This approach generally has led the large customers to switch suppliers more than the small customers have. Also, more suppliers have made efforts to solicit these large customers. Retail pricing that closely tracks wholesale prices provides efficient price signals to consumers. It creates incentives for customers to cut consumption during peak demand periods which, in turn, can reduce the risk that suppliers will exercise market power and can improve system reliability.

4. Some states have used auctions to procure POLR supply. Auctions may allow retail customers to get the benefit of competition in wholesale markets as suppliers compete to supply the necessary load.

5. One reason why retail competition for small customers may be slow to develop is that it is difficult for the consumer to find competitive supplier offers in the first place and to understand the terms and conditions of those offers. It also is unclear whether the effort to find this information is justified by the potential cost savings that can be realized. As and when there are more alternative suppliers, it may result in greater potential savings. But the need for clear and readily available information relating to competitive offers will remain.

Chapter 1—Industry Structure, Legal and Regulatory Background, Industry Trends and Developments

For the majority of the twentieth century, the electric power industry was dominated by regulated monopoly utilities. Beginning in the late 1960s, however, a number of factors contributed to a change in structure of the industry. In the 1970s, vertically-integrated utility companies (investor-owned, municipal, or cooperative) controlled over 95 percent of the electric generation. Typically, a single local utility sold and delivered electricity to retail customers under an exclusive franchise. Now, the electric power industry includes both utility and nonutility entities, including many new companies that produce and market electric energy in the wholesale and retail markets. This section will briefly describe the structural changes in the wholesale and retail electric power industry from the late 1960s until today. It provides a historical overview of the important legislative and regulatory changes that have occurred in the past several decades, as well as the trends seen over this time period that have led to increased competition in the electric power industry.

A. Industry Structure and Regulation

Participants in the electric power sector in the United States include investor-owned, cooperative utilities; Federal, State, and municipal utilities, public utility districts, and irrigation districts; cogenerators; nonutility independent power producers, affiliated power producers, and power marketers that generate, distribute, transmit, or sell electricity at wholesale or retail.

In 2004, there were 3276 regulated retail electric providers supplying electricity to over 136 million customers. Retail electricity sales totaled almost $270 billion in 2004. Retail customers purchased more than 3.5 billion megawatt hours of electricity. Active retail electric providers include electric utilities, Federal agencies, and power marketers selling directly to retail customers. These entities differ greatly in size, ownership, regulation, customer load characteristics, and regional conditions. These differences are reflected in policy and regulation. Tables 1–1 to 1–5 provide selected statistics for the electric power sector by type of ownership in 2004 based on information reported to the United States Department of Energy (DOE), Energy Information Administration (EIA).

1. Investor-Owned Utilities

Investor-owned utility operating companies (IOU) are private, shareholder-owned companies ranging in size from small local operations serving a customer base of a few thousand to giant multi-state holding companies serving millions of customers. Most IOUs are or are part of a vertically-integrated system that owns or controls generation, transmission, and distribution facilities/resources required to meet the needs of the retail customers in their assigned service areas. Over the past decade, under State retail competition plans many IOUs have undergone significant restructuring and reorganization. As a result, many IOUs in these states no longer own generation, but must procure the electricity they need for their retail customers from the wholesale markets.

IOUs continue to be a major presence in the electric power industry. In 2004 there were 220 IOUs serving approximately 94 million retail distribution customers, accounting for 68.9 percent of all retail customers and 60.8 percent of retail electricity sales. IOUs directly own about 39.6 percent of total electric generating capacity and generated 44.8 percent of total generation in 2004 to meet their retail and wholesale sales.

IOUs provide service to retail customers under state regulation of territories, finances, operations, services, and rates. States generally regulate bundled retail electric rates of IOUs under traditional cost of service rate methods. In states that have restructured their IOUs and IOU regulation, distribution services continue to be provided under monopoly cost-of-service rates, but retail customers are free to shop for their electricity supplier. IOUs operate retail electric systems in every state but Nebraska.

Under the Federal Power Act, the Federal Energy Regulatory Commission (FERC) regulates the wholesale

[2] Theoretically, competitive prices provide efficient incentives for all resource allocation (supply and consumption) decisions, and thus encourage efficient allocation of resources, including use of existing capacity, new investment by incumbent suppliers, entry by new suppliers, consumption, new investments by consumers.

electricity transactions (sales for resale) and unbundled transmission activities of IOUs (except in Alaska, Hawaii, and the ERCOT region of Texas).

2. Public Power Systems

The more than 2,000 public power systems include local, municipal, State, and regional public power systems, ranging in size from tiny municipal distribution companies to large systems like the Power Authority of the State of New York. Publicly owned systems operate in every State but Hawaii. About 1,840 of these public power systems are cities and municipal governments that own and control the day to day operation of their electric utilities.[3] Public power systems served over 19.6 million retail customers in 2004, or about 14.4 percent of all customers. Together, public power systems generated 10.3 percent of the Nation's power in 2004, but accounted for 16.7 percent of total electricity sales, reflecting the fact that many public systems are distribution-only utilities and must purchase their power supplies from others. Public power systems own about 9.6 percent of total generating capacity. Public power systems are overwhelmingly transmission- and wholesale-market-dependent entities. According to the American Public Power Association, about 70 percent of public power retail sales were met from wholesale power purchases, including purchases from municipal joint action agencies by the agencies' member systems. Only about 30 percent of the electricity for public power retail sales came from power generated by a utility to serve its own native load.

Regulation of public power systems varies among States. In some States, the public utility commission exercises jurisdiction in whole or part over operations and rates of publicly owned systems. In most States, public power systems are regulated by local governments or are self-regulated. Municipal systems are usually governed by the local city council or an independent board elected by voters or appointed by city officials. Other public power systems are operated by public utility districts, irrigation districts, or special State authorities.

On the whole, state retail deregulation/restructuring initiatives left untouched retail services in public power systems. However, some states allow public systems to adopt retail choice alternatives voluntarily.

[3] American Public Power Association.

3. Electric Cooperatives

Electric cooperatives are privately-owned non-profit electric systems owned and controlled by the members they serve. Members vote directly for the board of directors. In 2004, about 884 electric distribution cooperatives provided retail electric service to almost 16.6 million customers. In addition to these 884 distribution cooperatives, about 65 generation and transmission cooperatives (G&Ts) own and operate generation and transmission and secure wholesale power and transmission services from others to meet the needs of their distribution cooperative members and other rural native load customers. G&T systems and their members engage in joint planning and power supply operations to achieve some of the savings available under a vertically integrated utility structure for the benefit of their customers. Electric cooperatives operate in 47 States. Most electric cooperatives were originally organized and financed under the Federal rural electrification program and generally operate in primarily rural areas. Electric cooperatives provide electric service in all or parts of 83 percent of the counties in the United States.[4]

In 2004, electric cooperatives sold more than 345 million megawatt hours of electricity, served 12.2 percent of retail customers and accounted for 9.7 percent of electricity sold at retail. Nationwide electric cooperatives generated about 4.7 percent of total electric generation. Electric cooperatives own approximately 4.2 percent of generating capacity.

While some cooperative systems generate their own power and make sales of power in excess of their own members needs, most electric cooperatives are net buyers of power. Cooperatives nationwide generate only about half of the power needed to meet the needs of retail customers. Cooperatives secured approximately half of their power needs from other wholesale suppliers in 2004. Although cooperatives own and operate transmission facilities, almost all cooperatives are dependent on transmission service by others to deliver power to their wholesale and/or retail customers.

Regulatory jurisdiction over cooperatives varies among the States, with some States exercising considerable authority over rates and operations, while other States exempt cooperatives from State regulation. In addition to State regulation, cooperatives with outstanding loans under the Rural Electrification Act of 1936 also are subject to financial and operating requirements of the U.S. Department of Agriculture, which must approve borrower long-term wholesale power contracts, operating agreements, and transfer of assets.

Cooperatives that have repaid their RUS loans and that engage in wholesale sales or provide transmission services to others have been regulated by FERC as public utilities. EPACT 05 provided FERC additional discretionary jurisdiction over the transmission services provided by larger electric cooperatives.

[4] National Rural Electric Cooperative Association.

4. Federal Power Systems

Federally owned or chartered power systems include the Federal power marketing administrations, the Tennessee Valley Authority (TVA), and facilities operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, the Bureau of Indian Affairs, and the International Water and Boundary Commission. Wholesale power from federal facilities (primarily hydroelectric dams) is marketed through four Federal power marketing agencies: Bonneville Power Administration, Western Area Power Administration, Southeastern Power Administration, and Southwestern Power Administration. The PMAs own and control transmission to deliver power to wholesale and direct service customers. PMAs may also purchase power from others to meet contractual needs and sell surplus power as available to wholesale markets. Existing legislation requires that the PMAs and TVA give preference in the sale of their generation output to public power systems and to rural electric cooperatives.

Together, Federal systems have an installed generating capacity of approximately 71.4 gigawatts (GW) or about 6.9 percent of total capacity. Federal systems provided 7.2 percent of the Nation's power generation in 2004. Although most Federal power sales are at the wholesale level, they do engage in some end-use sales of generation. Federal systems nationwide directly served 39,845 retail customers in 2004, mostly industrial customers and about 1.2 percent of retail load.

5. Nonutilities

Nonutilities are entities that generate or sell electric power, but that do not operate retail distribution franchises. They include wholesale non-utility affiliates of regulated utilities, merchant generators, and PURPA qualifying facilities (industrial and commercial combined heat and power producers).

Power marketers that buy and sell power at wholesale or retail, but that do not own generation, transmission, or distribution facilities are also included in this category.

Non-QF (qualifying facilities) wholesale generators engaged in wholesale power sales in interstate commerce are subject to FERC regulation under the FPA. Power marketers that sell at wholesale are also subject to FERC oversight. Power marketers that sell only at retail are subject to State jurisdiction and oversight in the States in which they operate.

As retail electric providers, 152 power marketers reporting to EIA served about 6 million retail customers or about 4.4 percent of all retail customers and reported revenues of over $28 billion, on about 11.6 percent of retail electricity sold.

Nonutilities are a growing presence in the industry. In 2004 nonutilities owned or controlled approximately 408,699 megawatts or 39.6 percent of all electric generation capacity. In 1993 they owned only about 8 percent of generation. It is estimated that about half of nonutility generation capacity is owned by non-utility affiliates or subsidiaries of holding companies that also own a regulated electric utility.[5] Nonutilities accounted for about 33 percent of generation in 2004. Tables 1–1 through 1–5 summarize this information.

TABLE 1–1.—U.S. RETAIL ELECTRIC PROVIDERS 2004

Ownership	Number of electricity providers	Percent of total	Number of customers			Percent of total
			Full service	Delivery only	Total	
Publicly-owned utilities	2,011	61.4	19,628,710	6,125	19,634,835	14.4
Investor-owned utilities	220	6.7	90,970,557	2,879,114	93,849,671	68.9
Cooperatives	884	27	16,564,780	12,170	16,576,950	12.2
Federal Power Agencies	9	0.3	39,843	2	39,845	0.03
Power Marketers	152	4.6	6,017,611	0	6,017,611	4.4
Total	3,276	100	133,221,501	2,897,411	136,118,912	100.0

Source: American Public Power Association, 2006–07 Annual Directory & Statistical Report, from Energy Information Administration Form EIA–861, 2004 data.

Notes: Delivery-only customers represent the number of customers in a utility's service territory that purchase energy from an alternative supplier.

Ninety-eight percent of all power marketers' full-service customers are in Texas. Investor-owned utilities in the ERCOT region of Texas no longer report ultimate customers. Their customers are counted as full-service customers of retail electric providers (REPs), which are classified by the Energy Information Administration as power marketers. The REPs bill customers for full service and then pay the IOU for the delivery portion. REPs include the regulated distribution utility's successor affiliated retail electric provider that assumed service for all retail customers that did not select an alternative provider. Does not include U.S. territories.

TABLE 1–2.—U.S. RETAIL ELECTRIC SALES 2004

[Sales to ultimate consumers in thousands of MWhs]

	Full service	Energy only	Total	Percent
Publicly-owned utilities	525,596	65,466	591,062	16.7
Investor-owned utilities	2,148,351	3,359	2,151,720	60.8
Cooperatives	344,267	890	345,157	9.7
Federal Power Agencies	41,169	352	41,521	1.2
Power Marketers	207,696	203,202	410,898	11.6
Total	3,267,089	273,269	3,540,358	100.0

Source: American Public Power Association, 2006–07 Annual Directory & Statistical Report, from Energy Information Administration Form EIA–861, 2004 data.

Notes: Energy-only revenue represents revenue from a utility's sales of energy outside of its own service territory. Total revenue shows the amount of revenue each sector receives from both bundled (full service) and unbundled (retail choice) sales to ultimate customers. Eighty-five percent of the energy-only revenue attributed to publicly owned utilities represents revenue from energy procured for California's investor-owned utilities by the California Department of Water Resources Electric Fund. Ninety-eight percent of power marketers' full-service sales and revenues occur in Texas. Investor-owned utilities in the ERCOT region of Texas no longer report sales or revenue to ultimate consumers on EIA 861.

TABLE 1–3.—U.S. RETAIL ELECTRIC PROVIDERS 2004, REVENUES FROM SALES TO ULTIMATE CONSUMERS

	Sales in $ millions			Total
	Full service	Energy only	Delivery	
Publicly-owned utilities	$37,734	$5,787	$27	$43,548
Investor-owned utilities	162,691	128	8,746	171,565
Cooperatives	25,448	37	7	25,492
Federal Power Agencies	1,211	13	1	1,224
Power Marketers	17,163	11,000	0	28,162
Total	244,247	16,965	8,761	269,992

Source: American Public Power Association, 2006–07 Annual Directory & Statistical Report, from Energy Information Administration Form EIA–861, 2004 data.

[5] Edison Electic Institute.

TABLE 1–4.—U.S. ELECTRICITY GENERATION 2004

Electricity Generation 2004	Generation (thousands of MWhs)	% of Total
Publicly-owned utilities	397,110	10.3
Investor-owned utilities	1,734,733	44.8
Cooperatives	181,899	4.7
Federal Power Agencies	278,130	7.2
Power Marketers	42,599	1.1
Non-utilities	1,235,298	31.9
Total	3,869,769	100.0

Source: American Public Power Association, 2006–07 Annual Directory & Statistical Report, from Energy Information Administration Form EIA–861 and EIA–906/920 for generation. Data are for 2004, adjusted for joint ownership.

TABLE 1–5.—U.S. ELECTRIC GENERATION CAPACITY 2004

Ownership	Nameplate capacity (in MWs)	% of Total
Publicly-owned utilities	98,686	9.6
Investor-owned utilities	408,699	39.6
Cooperatives	43,225	4.2
Federal Power Agencies	71,394	6.9
Non-utilities	409,689	39.7
Total	1,031,692	100.0

Source: American Public Power Association, 2006–07 Annual Directory & Statistical Report, from Energy Information Administration Form EIA–860 for capacity, including adjustments for joint ownership. Data are for 2004.

B. Growth of the Electric Power Industry

1. Electric Power Characterized as a Natural Monopoly

The early electric power industry has been characterized as a natural monopoly.[6] This idea was, in part engendered by the work of Thomas Edison's protégé, Samuel Insull who acquired monopoly ownership over all central station electricity production in Chicago. Insull went on to publicly characterize electricity production as a ''natural monopoly'' and promote the idea of the public granting monopoly franchises to integrated generation/transmission utilities whose profits would be monitored and regulated.[7]

Over the years, experts have debated whether or not Samuel Insull was right. But he made a compelling argument, and the industry structure developed as if electricity was a natural monopoly. States granted monopoly franchises to vertically-integrated utilities. These franchises controlled the generation, transmission, and distribution of electricity. Public utility commissions were established to regulate the retail prices the electric utilities could charge.

Electric rates were set to cover the companies' reasonable costs plus a fair return on their shareholders' investment. Retail customers were charged a price based on the average system cost of production (including the investors' fair return on investment). In some circumstances, the public chose to establish publicly owned municipal utilities and cooperatives.

Most utilities began by building their own generation plants and transmission systems, primarily due to the cost and technological limitations on the distance over which electricity could be transmitted.[8] In the beginning, the federal role in the electric power industry was limited. Under the Federal Power Act of 1935 (FPA), the Federal Government regulated the price of IOUs' interstate sales of wholesale power (*e.g.*, sales of power between utility systems) and the price and terms of use of the interstate transmission system, which was used in these interstate sales of wholesale power. When this act was passed, interstate sales of electricity were limited. Over time utilities became more interconnected via high-voltage transmission networks that were constructed primarily for purposes of reliability but facilitated more robust interstate trade. However, this trade was slow to develop. Entry into these markets by nonutility generators was limited.

Until the late 1960s, this system appeared to work reasonably well. Utilities were able to meet increasing demand for electricity at decreasing prices, due to advances in generation technology that increased economies of scale and decreased costs.[9]

2. The Energy Crisis, Shift from Utility-Dominated Generation: Effects of PURPA on the Expansion of Nonutility Generation and Wholesale Power Markets

Several changes during the 1970s created a shift to a more competitive marketplace for wholesale power. Mainly, the large vertically integrated utility model became less profitable. Additional economies of scale were no

[6] Vernon Smith, *Regulatory Reform in the Electric Power Industry* (1995) (working paper, on file with the Department of Economics, University of Arizona).

[7] *See* Richard F. Hirsch, *Power Loss: The Origins of Deregulation and Restructuring in the American Electric Utility System*, MIT PRESS (1999); SHARON BEDER, POWER PLAY: THE FIGHT TO CONTROL THE WORLD'S ELECTRICITY, W.W. Norton (2003).

[8] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21,540, FERC Stats. & Regs. ¶ 31,036, 31,639 (1996), *order on reh'g*, Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 (1997); *order on reh'g*, Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC*, 225 F..3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC*, 535 U.S. 1 (2002)[hereinafter Order No. 888].

[9] *See* U.S. Dep't of Energy, Energy Info. Admin., *The Changing Structure of the Electric Power Industry: 1970–1991*, at 57 (March 1993), *available at http://tonto.eia.doe.gov/FTPROOT/electricity/0562.pdf* [hereinafter EIA 1970–1991].

longer being achieved; large generating units needed greater maintenance and experienced longer downtimes. Thus a bigger generation facility was no longer considered the most cost-efficient format.[10] Periods of rapid inflation and higher interest rates increased the costs of operating large, baseload generation plants,[11] and a more elastic-than-expected demand or load led to decreasing profits for large utilities.[12] Significant improvements in technology allowed smaller generation units to be constructed at lower costs.[13] As a result, lower cost generation sources could reach systems where customers were captive to high cost generators.[14] In addition, these technological advances made it more feasible for generation plants hundreds of miles apart to compete with each other [15] and for nonutility generators to enter the market; physically isolated systems became a thing of the past. Criticism of the cost-based regime also increased during this period with suggestions for alternate approaches to regulation and changes in industry structure. Critics of cost-based regulation argued that the industry structure provided limited opportunities for more efficient suppliers to expand and placed insufficient pressure on less efficient suppliers to improve their performance.[16]

Other events also influenced these changes. First, a major power blackout in the Northeastern U.S. in 1965 raised concerns about the reliability of weakly coordinated transmission arrangements among utilities.[17] Second, from October of 1973 to March of 1974, the Arab oil-producing nations imposed a ban on oil exports to the United States. The Arab oil embargo resulted in significantly higher oil prices through the 1970s, adding to inflation.[18]

Congress enacted the Public Utility Regulatory Policy Act of 1978 (PURPA)[19] as a response to the energy crises of the 1970s. A major goal of PURPA was to promote energy conservation and alternative energy technologies and to reduce oil and gas consumption through use of technology improvements and regulatory reforms. PURPA further created an opportunity for nonutilities to emerge as important electric power producers.[20] PURPA required electric utilities to interconnect with and purchase power from certain cogeneration facilities and small power producers meeting the criteria for a qualifying facility (QF). PURPA provided that the QF be paid at the utility's incremental cost of production, which FERC, in a departure from cost-based regulation, defined as the utility's avoided cost of power.[21] Box 1–1 discusses how the implementation of PURPA encouraged nonutilities generation suppliers by guaranteeing a market for the electricity they produced.[22] PURPA changed prevailing views that vertically integrated public utilities were the only sources of reliable power [23] and showed that nonutilities could build and operate generation facilities effectively and without disrupting the reliability of transmission systems.[24]

Box 1–1: State Implementation of PURPA

PURPA required states to define the utility's own avoided cost of production. This cost was used to set the price for purchasing a QF's output. Several states, including California, New York, Massachusetts, Maine, and New Jersey, enacted regulations that required utilities in these states to sign long-term contracts with QFs at prices that ended up being much higher than the utilities' actual marginal savings of not producing the power itself (avoided costs). The result of these regulations was that many utilities entered into long-term purchase contracts that ultimately proved uneconomic, and thus distorted the development of competitive wholesale markets. The costs of such contracts were subsequently reflected in retail rates as cost pass-throughs. The experience added to the dissatisfaction with retail utility service and regulation. *See* Joskow, Deregulation at 18.

PURPA was largely responsible for creating an independent competitive generation sector.[25] The response to PURPA was dramatic.

Before passage of PURPA, nonutility generation was primarily confined to commercial and industrial facilities where the owners generated heat and power for their own use where it was advantageous to do so. Although nonutility generation facilities were located across the country, development was heavily concentrated geographically with about two thirds located in California and Texas. Nonutility generation development advanced in States where avoided costs were high enough to attract interest and where natural gas supplies were available. Federal law largely precluded electric utilities from constructing new natural gas plants during the decade following enactment of PURPA, but nonutility generators faced no such restriction.

Annual QF filings at FERC rose from 29 applications covering 704 megawatts in 1980 to 979 in 1986 totaling over 18,000 megawatts. From 1980 to 1990 FERC received a total of 4610 QF applications for a total of 86,612 megawatts of generating capacity.[26]

Following PURPA, there were economic and technological changes in the transmission and generation sectors that further contributed to an influx of new entrants in wholesale generation markets who could sell electric power profitably with smaller scale technology than many utilities.[27] In addition to QFs, other non-utility power producers that could not meet QF criteria also began to build new capacity to compete in bulk power markets to meet the needs of load serving entities.[28] These entities were known as merchant generators or

[10] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,640–41.

[11] *Id.* at 31,639.

[12] Consumers reacted to electricity price increases, and growth in demand fell sharply below projections. See U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition* 39, OTA–E–409 (Washington, DC: U.S. Government Printing Office, May 1989) [hereinafter U.S. Congress, Office of Technology Assessment].

[13] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,641.

[14] *Id.*

[15] Severin Borenstein & James Bushnell, *Electricity Restructuring: Deregulation or Reregulation?*, 23 REGULATION 46, 47 (2000).

[16] Paul L. Joskow, *The Difficult Transition to Competitive Electricity Markets in the U.S.* 6–7 (AEI-Brookings Joint Ctr. for Regulatory Studies, Working Paper No. 03–13, 2003), available at *http://www.aei-brookings.org/admin/authorpdfs/page.php?id=271* [hereinafter Joskow, Difficult Transition].

[17] The response to the blackout included the formation of regional reliability councils and the North American Electric Reliability Council (NERC) to promote the reliability and adequacy of bulk power supply. U.S. Dept. of Energy, Energy Info. Admin., *The Changing Structure of the Electric Power Industry 2000: An Update*, at 109 (October 2000), *available at http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/update2000.pdf* [hereinafter EIA 2000 Update].

[18] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,639, n.9.

[19] Pub. L. No. 95–617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

[20] *See* EIA 1979–1991 at 22.

[21] PURPA specifically set forth criteria on who and what could qualify as QFs (mainly technological and size criteria). Two types of QFs were recognized: cogenerators, which sequentially produce electric energy and another form of energy (such as heat or steam) using the same fuel source, and small power producers, which use waste, renewable energy, or geothermal energy as a primary energy source. These nonutility generators are ''qualified'' under PURPA, in that they meet certain ownership, operating, and efficiency criteria. *See* EIA 1970–1991 at 5.

[22] *Id.* at 24.

[23] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,642.

[24] Joskow, Deregulation at 19.

[25] *Id.* at 17.

[26] CONG. RESEARCH SERV., COMM. ON ENERGY AND COMMERCE, 102D CONG., ELECTRICITY A NEW REGULATORY ORDER? 92 (Comm. Print 1991).

[27] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,644.

[28] Joskow, Deregulation at 19.

Independent Power Producers (IPPs).[29] By 1991, nonutilities (QFs and IPPs) owned about six percent of the electric power generating capacity and produced about nine percent of the total electricity generated in the United States,[30] and nonutility generating facilities accounted for one-fifth of all additions to generating capacity in the 1980s.[31]

FERC allowed many new utility and non-utility generators to sell electric power supply at wholesale market, rather than regulated rates.[32]

In 1988 FERC solicited public comments on three notices of proposed rulemaking (NOPRs) concerning the pricing of electricity in wholesale transactions: (1) Competitive bidding for new power requirements; (2) treatment of independent power producers; and (3) determination of avoided costs under PURPA.[33] These proposals would have moved towards greater use of a ''non-traditional'' market-based pricing approach in ratemaking as opposed to the agency's ''traditional'' cost-based approach. These FERC NOPRs proved controversial, and efforts to establish formal rules or policies adopting them were abandoned as commission membership changed. However, with the support of several Commission members and key FERC staff, the overall policy goals were still pursued on a case-by-case basis.

FERC laid the foundation for greater reliance on market-based mechanisms for Federal oversight of wholesale electricity prices on a case-by-case basis. Between 1983 and 1991, FERC considered more than 31 cases concerning approval of non-traditional rates involving independent power producers, power brokers/marketers, utility-affiliated power producers, and traditional franchised utilities. FERC approved all but four of these applications.[34] FERC staff wrote: ''The Commission has accepted non-traditional rates where the seller or its affiliate lacked or had mitigated market power over the buyer, and there was no potential abuse of affiliate relationships which might directly or indirectly influence the market price and no potential abuse of reciprocal dealing between the buyer and seller.'' [35]

In its process of determining whether the seller could exercise market power over the buyer, the FERC considered whether the seller or its affiliates owned or controlled transmission that might prevent the buyer from accessing other sources of power. A seller with transmission control might be able to force the buyer to purchase from the seller, thus limiting competition and significantly influencing the price the buyer would have to pay. The FPA does not allow rates to reflect an exercise of such market power.[36]

The potential for control of transmission to create market power, and the challenge that such control created in moving to greater reliance on market-based rates, was recognized. ''Because the Commission's very premise of finding market-based rates just and reasonable under the FPA is the absence or mitigation of market power, or the existence of a workably competitive market, and because the FPA mandates that the Commission prevent undue preference and undue discrimination, we believe the Commission is legally required to prevent abuse of transmission control and affiliate or any other relationships which may influence the price charged a ratepayer.'' [37]

Despite these developments, two limitations at that time were perceived to discourage development of competitive wholesale generation markets. First, IPPs and other generators of cheaper electric power could not easily gain access to the transmission grid to reach potential customers.[38] Under the FPA as then written, FERC authority to order transmission access was limited. FERC would subsequently find that ''intervening'' transmitting utilities would deny or limit transmission service to competing suppliers of generation service in order to protect demand for wholesale power supplied by their own generation facilities.[39] Second, unlike QFs that enjoyed a statutory exemption under PURPA, IPPs were subject to the Public Utility Holding Company Act of 1935 (PUHCA), which discouraged non-utilities from entering the generation business.[40]

3. Energy Policy Act of 1992 and FERC Order Nos. 888 and 889

Congress enacted the Energy Policy Act of 1992 (EPACT 92) [41] and amended the FPA and PUHCA to address two major limitations on the development of a competitive generation sector. First, EPACT 92 created a new category of power producers, called exempt wholesale generators (EWGs).[42] A EWG was an entity that directly, or indirectly through one or more affiliates, owned or operated facilities dedicated exclusively to producing electric power for sale in wholesale markets.[43] EWGs were exempted from PUHCA regulations, thus eliminating a major barrier for utility-affiliated and nonaffiliated power producers that wanted to compete to build new non-rate-based power plants.[44] EPACT 92 also expanded

[29] Order No. No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,642.

[30] EIA 1970–1991 at vii.

[31] *Id.* at 27.

[32] *See* Order No. No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,643.

[33] *See Regulations Governing Bidding Programs*, Notice of Proposed Rulemaking, 53 FR 9,324 (March 22, 1988), FERC Stats. & Regs. ¶ 32,455 (1988) (modified by 53 FR 16,882 (May 12, 1988)). This proposal would have adopted competitive bidding into the process of acquiring and pricing power from QFs and would have largely abandoned the prior avoided cost purchase rates.

See Regulations Governing Independent Power Producers, Notice of Proposed Rulemaking, 53 FR 9,327 (March 22, 1988), FERC Stats. & Regs. ¶ 32,456 (1988) (modified by 53 FR 16882 (May 12, 1988)). This proposal would have relaxed rate review and regulation of wholesale sales by independent power producers, and other public utilities that did not operate retail distribution systems.

See Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Notice of Proposed Rulemaking, 53 FR 9,331 (March 22 1988), FERC Stats. & Regs. ¶ 32,457 (1988) (modified by 53 FR 16882 (May 12, 1988)). This proposal would have revised the elements used in making administrative determinations of avoided costs for rates for utilities' PURPA QF purchases.

[34] *Hearing on National Energy Security Act of 1991 (Title XV) Before the S. Comm. on Energy and Natural Resources*, 102d Cong. 97 (1991) (Statement of Cynthia A. Marlette, Associate General Counsel for Hydroelectric and Electric, Federal Energy Regulatory Commission).

[35] *Id.* at 100.

[36] *Id.*

[37] *Id.* at 102.

[38] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,642–43.

[39] Joskow, Deregulation at 21. *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,644.

[40] Joskow, Deregulation at 23. Under PUHCA, those public utility holding companies that did not qualify for an exemption were subject to extensive regulation of their financial activities and operations. These regulations limited the availability of exemptions and the growth and expansion of electric utility companies. PUHCA restricted utility operations to a single integrated public-utility system and prevented utility holding companies from owning other businesses that were not reasonably incidental or functionally related to the utility business. Further, registered holding companies had to obtain Securities and Exchange Commission (SEC) approval for the sale and issuance of securities, for transactions among their affiliates and subsidiaries and for services, sales, and construction contracts, and they were required to file extensive financial reports with the SEC.

Although PUHCA provided for limited exemptions, it was long criticized as discouraging new investment in the electric utility industry by non-utility entities. Mergers and acquisitions of utilities subject to PUHCA have largely been by other domestic and foreign utilities. Investment by entities outside the industry has been limited, as these entities avoid the extensive regulations imposed by PUHCA.

[41] Pub. L. No. 102–486, 106 Stat. 2776 (1992), codified at, among other places, 15 U.S.C. 79z–5a and 16 U.S.C. 796(22–25), 824j–l.

[42] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,645.

[43] Joskow, Deregulation at 24.

[44] *See EIA 1970–1991* at 30; Joskow, Deregulation at 23.

FERC's authority to order transmitting utilities to provide transmission service for wholesale power transmission to any electric utility, Federal power marketing agency, or any person generating electric energy in wholesale electricity markets.[45] The amendment provided for orders to be issued on a case by case basis following a hearing if certain protective conditions were met. Though FERC implemented this new authority, it ultimately concluded that procedural limitations limited its reach and a broader remedy was needed to effectively eliminate pervasive undue discrimination in the provision of transmission service.

Thus, in April 1996, FERC adopted Order No. 888 in exercise of its statutory obligation under the FPA to remedy undue transmission discrimination to ensure that transmission owners do not use their transmission facility monopoly to unduly discriminate against IPPs and other sellers of electric power in wholesale markets. In Order No. 888, the FERC found that undue discrimination and anticompetitive practices existed in the provision of electric transmission service by public utilities in interstate commerce, and determined that non-discriminatory open access transmission service was one of the most critical components of a successful transition to competitive wholesale electricity markets. Accordingly, FERC required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access transmission tariffs (OATTs) containing certain non-price terms and conditions and to ''functionally unbundle'' wholesale power services from transmission services.[46] To functionally unbundle, a public utility was required to: (1) Take wholesale transmission services under the same tariff of general applicability as it offered its customers; (2) state separate rates for wholesale generation, transmission and ancillary services; and (3) rely on the same electronic information network that its transmission customers rely on to obtain information about the utility's transmission system.[47]

Concurrent with the issuance of Order No. 888, FERC issued Order No. 889[48] that imposed standards of conduct governing communications between the utility's transmission and wholesale power functions, to prevent the utility from giving its power marketing arm preferential access to transmission information. Order No. 889 requires each public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Sametime Information System, to provide information regarding available transmission capacity, prices, and other information that will enable transmission service customers to obtain open access non-discriminatory transmission service.[49]

FERC, through Order No. 888, also encouraged grid regionalization through the formation of Independent Systems Operator (ISOs). Participating utilities would voluntarily transfer operating control of their transmission facilities to the ISO to ensure independent operation of the transmission grid.[50] The ISO also could achieve coordination, reliability, and efficiency benefits by having regional control of the grid.[51] Participation in an ISO remained voluntary, however, and it only occurred in some areas of the country. It was not implemented in other areas.[52] Together, Order Nos. 888 and 889 serve as the primary federal foundation for providing transmission service and information about the availability of transmission service.[53]

4. Restructuring Initiatives in Retail Markets: State-Authorized Retail Electricity Competition

Beginning in the early 1990s, several states with high electricity prices began to explore opening retail electric service to competition. With retail competition, customers could choose their electric supplier, but the delivery of electricity would still be done by the local distribution utility.

Substantial rate disparity existed among and between utilities in different states. For example, customers in New York paid more than two and one-half times the rates paid by customers in Kentucky in 1998. Rates in California were well over twice the rates in Washington.[54] Some of this disparity in price from state to state can be attributed to different natural resource endowments across regions—most important the hydroelectric opportunities in the Northwest and some states such as Kentucky and Wyoming with abundant coal reserves—and the resulting diverse costs of fuel used for generation by utilities. Another reason for the price disparity may be that some states required utilities to enter into PURPA contracts that subsequently resulted in prices higher than the cost to acquire power in the wholesale market.[55] Utilities' QF contract costs were included as part of the bundled service provided to retail customers; ultimately the cost of these high-cost PURPA contracts was reflected in the regulated retail prices.[56] Additionally, utilities in some states invested heavily in large, new nuclear power plants, and coal plants, which turned out to be more expensive than anticipated, adding to the retail rate shock.

Not only were there large disparities in utility rates among states, but many industrial customers contended that they subsidized lower rates for residential customers. For example, a survey by the Electricity Consumers Resource Council in 1986 contended that industrial electricity consumers paid more than $2.5 billion annually in subsidies to other electricity customers (*e.g.*, commercial and residential customers). By allowing industrial customers to choose a new supplier, it was presumed that these subsidies could be avoided and industrial customer electricity prices would decrease.[57]

This rate disparity provided an impetus for states to initiate their restructuring efforts; thus it is not surprising that many of the states that led the restructuring movement were those with higher prices.[58] As of 2004 the disparity in retail prices among the states persisted, as illustrated in Figure 1–1, below.

[45] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,645.

[46] *Id.* at ¶ 31,654.

[47] *Id.* Order No. 888 also clarified FERC's interpretation of the Federal/state jurisdictional boundaries over transmission and local distribution. While it reaffirmed that FERC has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, it nevertheless recognized the legitimate concerns of state regulatory authorities for the development of competition within their states. FERC therefore declined to extend its unbundling requirement to the transmission component of bundled retail sales and reserved judgment on whether its jurisdiction extends to such transactions. The United States Supreme Court affirmed this element of Order No. 888. *New York* v. *FERC*, 535 U.S. 1 (2002).

[48] *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 61 FR 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 at 31,583 (1996), *order on reh'g,* Order No. 889–A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g,* Order No. 889–B, 81 FERC ¶ 61,253 (1997).

[49] Joskow, Deregulation at 29.

[50] EIA 2000 Update at 66.

[51] *Id.* at 66, 68, 80.

[52] *Id.* at 67.

[53] Joskow, Deregulation at 27–28.

[54] EIA 2000 Update at ix.

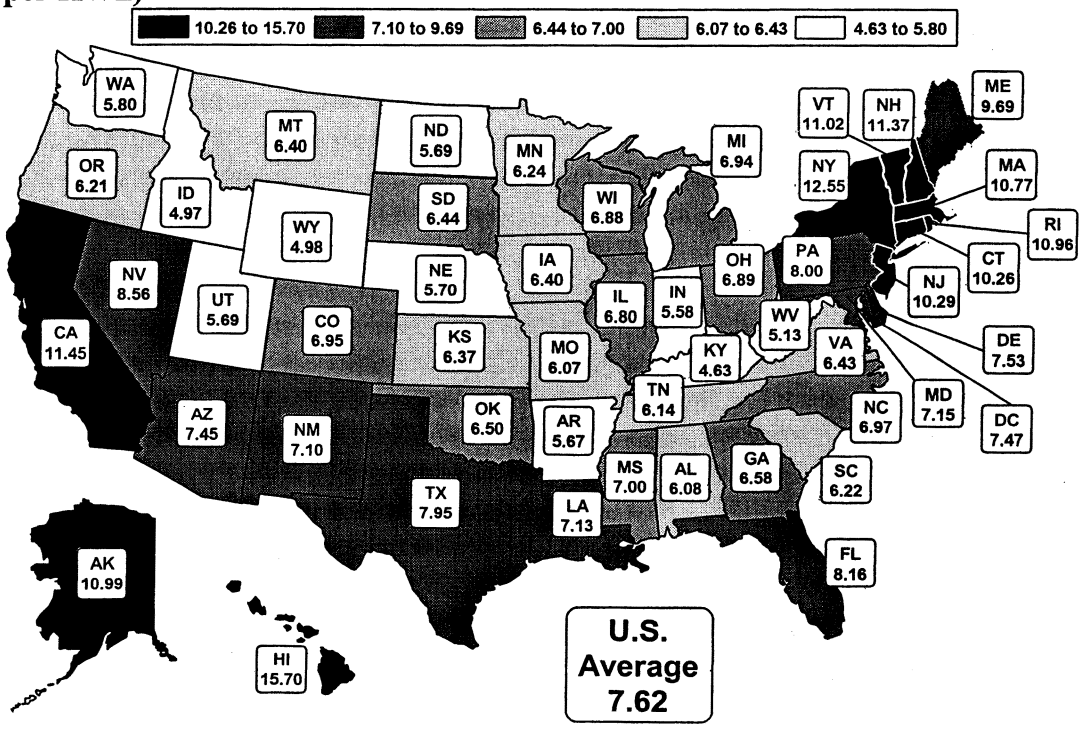
[55] *See* discussion *infra*, Box 1–1.

[56] Joskow, *Deregulation* at 19.

[57] Electricity Consumers Resource Council, Profiles in Electricity Issues: Cost-of-Service Survey (Mar. 1986).

[58] *EIA 2000 Update* at 43.

Figure 1-1: U.S. Electric Power Industry, Average Retail Price of Electricity by State, 2004 (cents per KWh)



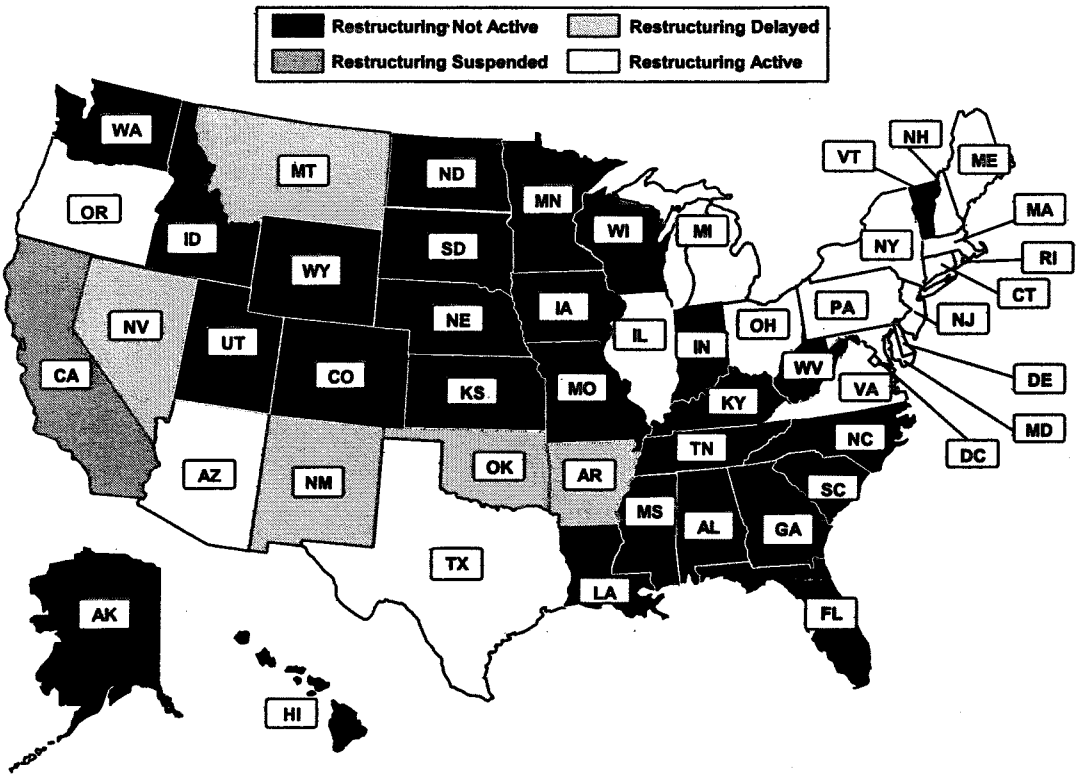
Source: EIA, Electric Power Annual 2004, Figure 7.4

Not all state commissions adopted retail competition plans, although most of them considered the merits and implications of competition, deregulation, and industry restructuring. States such as California and those in New England and the mid-Atlantic region, with high electricity rates, were among the most aggressive in adopting retail competition in the hope of making lower rates available to their retail customers. As of July 2000, 24 states and the District of Columbia had enacted legislation or passed regulatory orders to restructure their electric power industries. Two states had legislation or regulatory orders pending, while 16 states had ongoing legislative or regulatory investigations. There were only eight states where no restructuring activities had taken place.[59] Since 2000, however, no additional states have announced plans to implement retail competition programs, and several states that had introduced such programs have delayed, scaled back, or cancelled their programs entirely (see Figure 1–2 below).[60] The California energy crisis is widely-perceived to have halted interest by states in restructuring retail markets. These issues are further discussed in Chapter IV, Retail Competition.

[59] *Id.* at 81–82.

[60] Paul L. Joskow, *Markets for Power in the United States: An Interim Assessment*, ENERGY J. 2 (2006) [hereinafter Joskow, Interim Assessment].

Figure 1-2: Status of State Electric Industry Restructuring Activity, 2003



Source: EIA, available at http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf

5. Development of Regional Transmission Organizations and Regional Wholesale Markets

Even after issuance of Order Nos. 888 and 889, FERC continued to receive complaints about transmission owners discriminating against independent generating companies. Transmission customers remained concerned that electric utilities' implementation of functional unbundling did not produce complete separation between operating the transmission system and marketing and selling electric power in wholesale markets. Also, there were concerns that Order No. 888 changes made some discriminatory behavior in transmission access more subtle and difficult to identify and document.

The electric industry continued to transform since FERC issued Order Nos. 888 and 889, in response to competitive pressures and state retail restructuring initiatives. Utilities today purchase more wholesale power to meet their load than in the past and are expanding reliance on availability of other utility transmission facilities for delivery of power. Retail competition increased significantly in the years following adoption of Order No. 888. These state initiatives brought about the divestiture of generation plants by traditional electric utilities. In addition, this period saw a number of mergers among traditional electric utilities and among electric utilities and gas pipeline companies, large increases in the number of power marketers and independent generation facility developers entering the marketplace, and the establishment of ISOs as managers of large parts of the transmission system. Trade in wholesale power markets has increased significantly and the Nation's transmission grid is being used more heavily and in new ways.

In response to continuing complaints of discrimination and lack of transmission availability and in the wake of an expanding competitive power industry, in December 1999, FERC issued Order No. 2000.[61] This order recognized that Order No. 888 set the foundation upon which to attain competitive electric markets, but did not eliminate the potential to engage in undue discrimination and preference in the provision of transmission service.[62] Thus, FERC concluded that regional transmission organizations (RTOs) could eliminate transmission rate pancaking,[63] increase region-wide reliability, and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. Accordingly, FERC encouraged the voluntary formation of RTOs.

RTOs are entities set up in response to FERC Order Nos. 888 and 2000 encouraging utilities to voluntarily enter into arrangements to operate and plan regional transmission systems on a nondiscriminatory open access basis. RTOs are independent entities that control and operate regional electric transmission grids for the purpose of

[61] *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 16 (1999), *order on reh'g*, Order No. 2000–A, FERC Stats. & Regs. ¶ 30,092, 65 FR 12,088 (2000), *aff'd, Public Utility District No. 1* v. *FERC*, 272 F.3d 607 (DC Cir. 2001) [hereinafter Order No. 2000].

[62] In Order No. 2000, FERC found that ''opportunities for undue discrimination continue to exist that may not be remedied adequately by [the] functional unbundling [remedy of Order No. 888].'' Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,105.

[63] The term ''rate pancaking'' refers to circumstances in which a transmission customer must pay separate access charges for each utility service territory crossed by the customer's contract path.

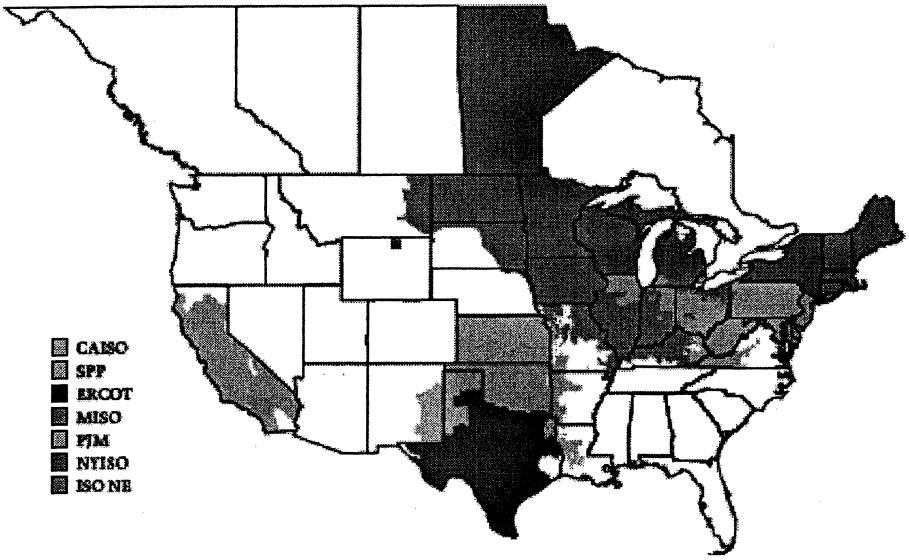
promoting efficiency and reliability in the operation and planning of the transmission grid and for ensuring non-discrimination in the provision of electric transmission services.

FERC has approved RTOs or ISOs in several regions of the country including the Northeast (PJM, New York ISO, ISO-New England), California, the Midwest (MISO) and the South (SPP), as shown in Figure 1–3 below. By the end of 2004, regions accounting for 68 percent of all economic activity in the United States had chosen the RTO option.[64]

In 2004 and 2005, the PJM grid expanded substantially to include several additional service territories in the Midwest. In 2004, the territories serviced by Commonwealth Edison (ComEd), American Electric Power (AEP), and Virginia Electric and Power (VEPCO) joined PJM. The expansion continued in 2005 with the addition of Duquesne Light. The area now in PJM covers about 18 percent of total electricity consumption in the United States.[65] In most cases, RTOs have assumed responsibility to calculate the amount of available transfer capability (ATC) for wholesale trades across the footprint of the RTO. RTOs also are responsible for regional planning, at least for facilities necessary for reliability above a certain voltage.

As of 2004, all of the RTOs in operation coordinate dispatch of the generators in their systems and provide transmission services under a single RTO open access tariff. In addition, RTOs operate regional organized energy markets, including a short-term market which prices energy, congestion, and losses. RTOs in the East all offer day-ahead and real-time markets, while California and Texas offer real-time market alone. Further, all RTOs in current operation use or plan to use some form of locational pricing and have independent market monitors.[66]

Figure 1-3: RTO Configurations in 2004



Source: FERC State of the Market Report for 2004, Figure 2, Page 53

6. August 2003 Blackout

On August 14, 2003, an electrical outage in Ohio precipitated a cascading blackout across seven other states and as far north as Ontario, leaving more than 50 million people without power.[67] The August 2003 blackout was the largest blackout in the history of the United States, leaving some parts of the nation without power for up to four days and costing between $4 billion and $10 billion.[68] The 2003 blackout was the eighth major blackout experienced in North America since the 1965 Northeast Blackout.

A Joint U.S.-Canada Power System Outage Task Force issued a final Blackout Report in April 2004. The Blackout Report identified factors that were common to some of the eight major outage occurrences from the 1965 Northeast Blackout through the 2003 Blackout, as shown below:

(1) Conductor contact with trees; (2) overestimation of dynamic reactive output of system generators; (3) inability of system operators or coordinators to visualize events on the entire system; (4) failure to ensure that system operation was within safe limits; (5) lack of coordination on system protection; (6) ineffective communication; (7) lack of ''safety nets;'' and (8) inadequate training of operating personnel.[69]

7. Recent Developments: Enactment of the Energy Policy Act of 2005

In 2005, Congress passed the Energy Policy Act of 2005 (EPACT 2005),[70] which amended the core statutes (FPA, PURPA, PUHCA) governing the electric

[64] Fed. Energy Regulatory Comm'n, Office of Mkt. Oversight and Investigations, *State of the Markets Report: An Assessment of Energy Markets in the United States in 2004*, at 51 (2005) [hereinafter FERC State of the Markets Report 2005], *available at http://www.ferc.gov/legal/staff-reports.asp.*

[65] *Id.* at 53.

[66] *Id.* at 52.

[67] U.S. Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and* Recommendations, April 2004, at 1.

[68] *Id.*

[69] *Id.* at 107.

[70] Pub. L. No. 109–58, 119 Stat. 594 (2005).

power industry. Several key provisions of EPACT 2005 are:

• Authorizes FERC to certify an Electric Reliability Organization to propose and enforce reliability standards for the bulk power system. EPACT 2005 authorized penalties for violation of these mandatory standards.

• Authorizes the Secretary of Energy to conduct a study of electricity congestion within one year of the enactment of the Energy Policy Act, and every three years thereafter. Authorizes the Secretary of Energy to designate ''National Interest Electric Transmission Corridors'' based on these congestion studies. EPACT 05 also authorizes FERC in limited circumstances to approve the siting of transmission facilities in these corridors, in states which lack such authority or do not exercise it in a timely manner. Proponents of this new federal authority have argued that it will facilitate the construction of new transmission lines and, thus, help alleviate transmission congestion that can impair competition in electric markets.

• Requires FERC to establish incentive-based rate treatments for public utilities' transmission infrastructure in order to promote capital investment in facilities for the transmission of electricity, attract new investment with an attractive return on equity, encourage improvement in transmission technology, and allow for the recovery of prudently incurred costs related to reliability and improved transmission infrastructure. Proponents of this authority contend it will encourage the expansion of transmission capacity and, thus, help foster greater competition in electric markets.

• Permits FERC to terminate, prospectively, the obligation of electric utilities to buy power from QFs, such as industrial cogenerators. FERC may do so when the QFs in the relevant area have adequate opportunities to make competitive sales, as defined by EPACT 2005. The premise is that growth in competitive opportunities in electric markets is negating the need for PURPA's ''forced sale'' requirements.

• Repeals PUHCA 1935 and replaces it with new PUHCA 2005, which provides FERC and state access to books and records of holding companies and their members and provides that certain holding companies or states may obtain FERC-authorized cost allocations for non-power goods or services provided by an associate company to public utility members in the holding company. PUHCA 2005 also contains a mandatory exemption from the Federal books and records access provisions for entities that are holding companies solely with respect to EWGs, QFs or foreign utility companies. The goal of these provisions is to reduce legal obstacles to investment in the electric utility industry and, thus, help facilitate the construction of adequate energy infrastructure.

C. Recent Trends Related to Competition in the Electric Energy Industry

Given the previous reviewed of electric industry legal and regulatory background, this section discusses several more recent electric industry policy developments and characteristics.

1. Technological Improvements in Generation and Transmission

Electric power industry restructuring has been largely sustained by technological improvements in gas turbines. No longer is it necessary to build a large generating plant to exploit economies of scale. Combined-cycle gas turbines reach maximum efficiency at 400 megawatts (MW), while aero-derivative gas turbines can be efficient at sizes as low as 10 MW. These new gas-fired combined cycle plants can be more energy efficient and less costly than the older coal-fired power plants.[71] Technological advances in transmission equipment have made transmission of electric power over long distances more economical. As a result, generating plants hundreds of miles apart can compete with each other and customers can be more selective in choosing an electricity supplier.[72]

Despite these increases in technology, the Edison Electric Institute reports that investment in transmission declined from 1975 through 1997. See Figure 1–4. Since 1998, transmission investment has increased annually, but remains below 1975 levels. Over that same period, electricity demand has more than doubled, resulting in a significant decrease in transmission capacity relative to demand. Box 1–2 discusses some suggested explanations for this trend of declining transmission investment.

Box 1–2: Decline in Transmission Investment

Transmission is the physical link between electricity supply and demand. Without adequate transmission capacity, wholesale competition cannot function effectively.

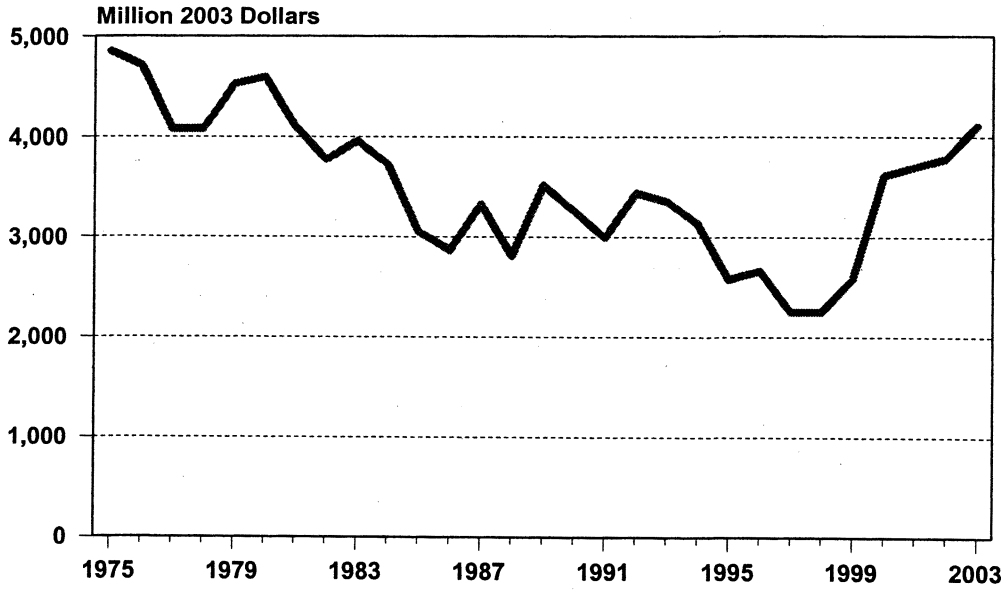
Some of the reasons suggested for the decline in transmission investment between 1975 and 1997 (see Figure 1–4) are: an overbuilt system prior to 1975, lack of available capital due to other investment activities by vertically-integrated utilities, the protection of vertically-integrated utility generation from competition and regulatory uncertainty.

Another explanation for the long decline in transmission investment is the difficulty of siting new transmission lines. Siting can bring long delays and negative publicity. NIMBY-based local opposition is usually strong. Also, many state processes require a showing of benefits to the state to site a transmission line. This can create barriers for transmission facilities that primarily benefit interstate commerce.

[71] EIA 2000 Update at ix. The size of the cost improvements depends on the underlying fuel prices.

[72] *Id.*

Figure 1.4: Transmission Expenditures of EEI Members, 1975-2003



Source: Edison Electric Institute

2. Increase in Nonutility Generation Suppliers

The market participation of utilities and other suppliers in the generation of electricity has changed over the past few decades. The change began with the passage of PURPA, when nonutilities were promoted as energy-efficient, environmentally-friendly, alternative sources of electric power. The change continued through the issuance of Order No. 888, which opened up the transmission grid to suppliers other than utilities.[73] Until the early 1980s, the electric utilities' share of electric power production increased steadily, reaching 97 percent in 1979.[74] By 1991, however, the trend had reversed itself, and the electric utilities' share declined to 91 percent.[75] By 2004, regulated electric utilities' share of total generation continued to decline (63.1 percent in 2004 versus 63.4 percent in 2003) as IPPs' share increased (28.2 percent versus 27.4 percent in 2003).[76]

This trend is illustrated by comparing the increases in capacity for utility and nonutility generation suppliers, as shown in Figure 1–5 below. While most of the existing capacity, and until the late 1980s, most of the additions to capacity, have been built by electric utilities, their share of capacity additions declined in the 1990s. Between 1996 and 2004, roughly 74 percent of electricity capacity additions have been made by independent power producers.

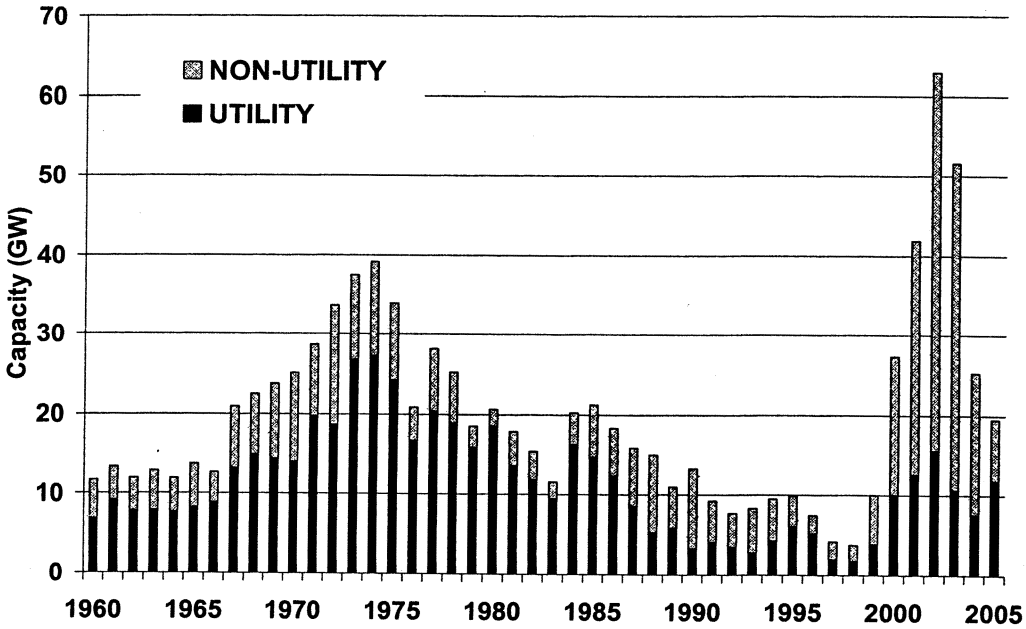
[73] *Id.* at 23.

[74] EIA 1970–1991 at vii.

[75] *Id.*

[76] U.S. Dept. of Energy, Energy Information Administration, *Electric Power Annual 2004*, at 2 (November 2005), *available at http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf [hereinafter EIA Electric Power Annual 2004].*

Figure 1-5: U.S. Electric Generating Capacity Additions: Non-Utility Growth Overtakes Utility in 2000-2004



Source: FERC Analysis of Platts PowerDat data

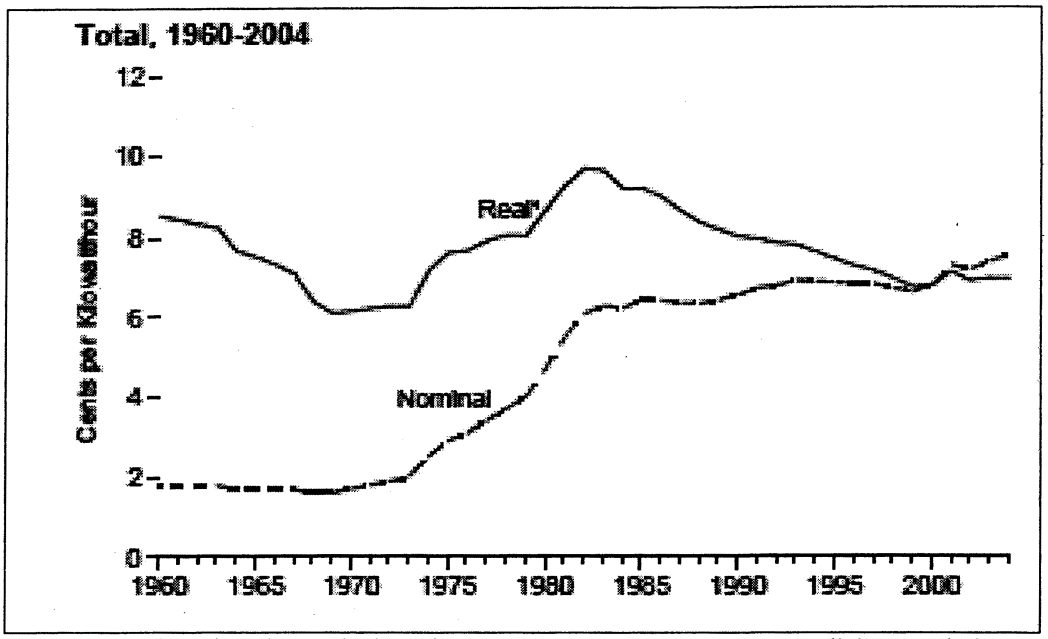
3. Retail Prices of Residential Electricity

As seen in Figure 1–6 below, between 1970 and 1985, national average residential electricity prices more than tripled in nominal terms, and increased by 25 percent (after adjusting for inflation) in real terms.[77] On a national level, real retail electricity prices began to fall after the mid-1980s until 2000–2001, as fossil fuel prices and interest rates declined and inflation moderated significantly.[78] Real retail prices have since stayed flat through 2004.

[77] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,640.

[78] Joskow, Difficult Transition at 7.

Figure 1-6: National Average Retail Prices of Electricity for Residential Customers



1- In chained (2000) dollars, calculated by using gross domestic product implicit price deflators.
Source: Energy Information Administration Annual Energy Review 2004

4. Changing Patterns of Fuel Use for Generation—Reaction to Increased Oil Prices and Clean-Air Environmental Regulations

For utilities, coal was the fuel most commonly used for many years, providing 46 percent of utilities' generation in 1970 and more than 50 percent since 1980. When world oil prices escalated in the 1970s, oil-fired and gasoline-fired generation's share of electricity supply began decreasing.

Hydroelectric power has also played a large role in the supply of electric power, but its use has declined relative to other major fuels mainly because there are a limited number of economical sites for hydroelectric projects. Nuclear power grew to be the second largest fuel source in 1991 but was not expected to continue to increase.[79]

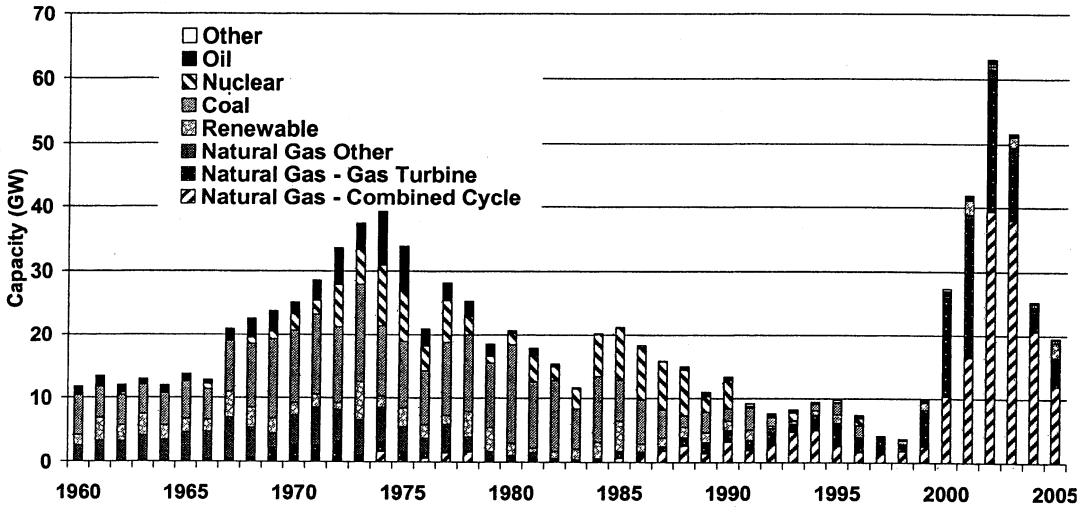
For nonutilities, natural gas has been the major fuel. Indeed, new capacity added in recent years shows the prevalence of natural gas to fuel new plants.[80] As shown in Figure 1–7, recent plant additions illustrate this change in fuel sources. This increased use of natural gas also is due, in part, to the Clean Air Act Amendments of 1990 (CAA) and state clean air requirements. The CAA sought to address the most widespread and persistent pollution problems caused by hydrocarbons and nitrogen oxides—both of which are prevalent with traditional coal and petroleum-based generating plants. The CAA fundamentally changed the generation business because it would no longer be costless to emit air pollutants. As a result of these requirements, many generation owners and new generation plant developers turned to cleaner-burning natural gas as the fuel source for new generation plants. California has been very dependent on gas-fired generation because of its specific air quality standards.[81]

[79] EIA 1970–1991 at 20.

[80] EIA Electric Power Annual 2004 at 2.

[81] Fed. Energy Regulatory Comm'n, *The Western Energy Crisis, The Enron Bankruptcy, & FERC's Response*, at 1, *available at http://www.ferc.gov/industries/electric/indus-act/wec/chron/chronology.pdf.*

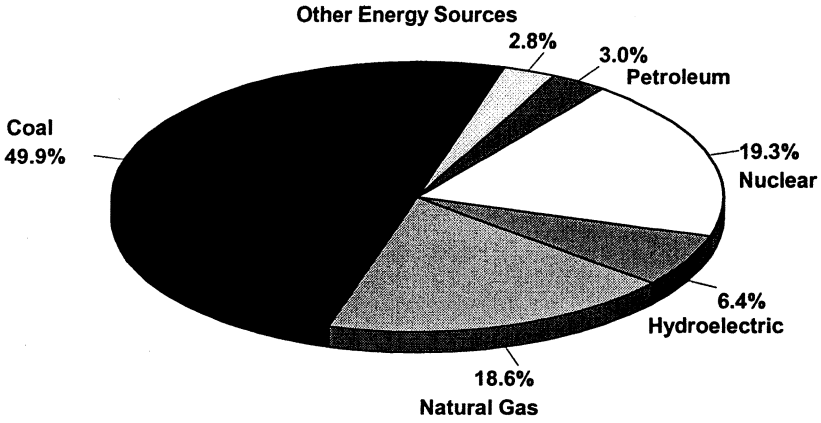
Figure 1-7: Gas Has Recently Been Dominant Fuel



Source: FERC Analysis of Platts PowerDat data

The result of these plant additions through December 2005 is that 49.9 percent of the nation's electric power was generated at coal-fired plants (Figure 1–8). Nuclear plants contributed 19.3 percent, 18.6 percent was generated by natural gas-fired plants, and 2.5 percent was generated at petroleum liquid-fired plants. Conventional hydroelectric power provided 6.6 percent of the total, while other renewables (primarily biomass, but also geothermal, solar, and wind) and other miscellaneous energy sources generated the remaining electric power.

Figure 1-8: Net Generation Shares by Energy Source: Total (All Sectors), January-December 2005



Source EIA, Electric Power Monthly with data for December 2005.

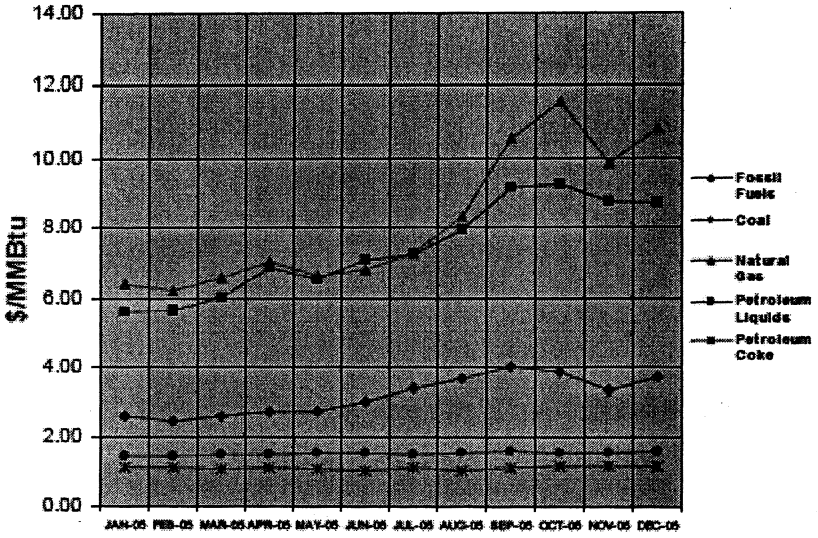
The trend toward gas-fueled capacity additions may be changing, however. In the coming years, more coal-fired generation capacity may be built. Two major reasons may explain coal's resurgence: (1) The relative price of natural gas compared to coal has increased substantially in recent years and (2) the cost of environmental equipment for coal plants, such as scrubbers, has decreased. To the extent that combined-cycle gas-fired units were built on the assumption that natural gas would be relatively inexpensive and that cleaning technology for coal plants would drive the price of coal significantly higher, both these assumptions have proved questionable with time. The Department of Energy's Energy Information Administration (EIA) estimated only 573 megawatts of new coal generation would be added nationally in 2005, which compares with an estimate of 15,216 megawatts of gas-fired additions for the same year. For the year 2009, however, predicted trends shift—the EIA projects that 8,122

MW of new coal generation will be added that year, whereas only 5,451 MW of gas-fired generation additions are predicted for that year.[82] The Department of Energy predicts a resurgence of coal-fired generation will continue as far into the future as 2025.[83]

5. Price Changes in Fuel Sources

Natural gas prices have been increasing in recent years, due in part to the historically high level of petroleum prices. Natural gas prices experienced a 51.5 percent increase between 2002 and 2003, a 10.5 percent increase between 2003 and 2004, and a 37.6 percent increase between 2004 and 2005. Strong demand for natural gas, as well as natural gas production disruptions in the Gulf of Mexico, contributed to these price increases. As shown in Figure 1–9, for December 2005 the overall price of fossil fuels was influenced by the increases in price of natural gas. In December 2005, the average price for fossil fuels was $3.71 per MMBtu, 10.1 percent higher than for November 2005, and 44.4 percent higher than in December 2004. As natural gas prices increase relative to coal prices, the change may make development of clean-burning coal plants more economical than they were when natural gas fuel prices were lower.

Figure 1-9: Electric Power Industry Fuel Costs, January 2005 through December 2005



Source: Source EIA, Electric Power Monthly with data for January 2006.

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

Many IOUs have fundamentally reassessed their corporate strategies to function more as competitive, market-driven businesses in response to an increasingly competitive business environment.[84] One result is that there was a wave of mergers and acquisitions in the late 1980s through the late 1990s between traditional electric utilities and between electric utilities and gas pipeline companies.

IOUs also have divested a substantial number of generation assets to IPPs or transferred them to an unregulated subsidiary within the company.[85] Even though FERC-regulated IOUs have functionally unbundled generation from transmission, and some have formed RTOs and ISOs, many utilities have divested their power plants because of state requirements. Some states that opened the electric market to retail competition view the separation of power generation ownership from power transmission and distribution ownership as a prerequisite for retail competition. For example, California, Connecticut, Maine, New Hampshire, and Rhode Island enacted laws requiring utilities to divest their power plants. In other states, the state public utility commission may encourage divestiture to arrive at a quantifiable level of stranded costs for purposes of recovery during the transition to competition.[86]

Since 1997, IOUs have divested power generation assets at unprecedented levels,[87] and these power plant divestitures have also reduced the total number of IOUs that own generation capacity.[88] A few utilities have decided to sell their power plants, as a business strategy, deciding that they cannot compete in a competitive power market. In a few instances, an IOU has divested power generation capacity to mitigate potential market power resulting from a merger.[89] As described in Table 1–6 below, between 1998 and 2001, over 300 plants, representing nearly 20% of U.S. installed generating capacity, changed ownership.

There was no significant electric power company merger activity from 2001 to 2004, but this changed in 2004, when utilities and financial institutions exhibited growing interest in mergers and acquisitions, prompting many

[82] *See* EIA Electric Power Annual 2004 at 17, table 2.4, *available at http://www.eia.doe.gov/cneaf/electricity/epa/epat2p4.html.*

[83] *See* U.S. Dept. of Energy, Nat'l Energy Tech. Lab, *Tracking New Coal-Fired Power Plants*, at 3–4, *available at http://www.netl.doe.gov/coal/refshelf/ncp.pdf* (predicting 85 GW of new coal capacity created by 2025).

[84] *See* U.S. Congress, Office of Technology Assessment at 47.

[85] EIA 2000 Update at 91.

[86] *Id.* at 105–06.

[87] *Id.* at 105.

[88] *Id.* at 91.

[89] *Id.* at 106.

analysts to herald 2004 as the inauguration of a new round of consolidation in the power sector.[90] One utility-to-utility acquisition was closed [91] and three were announced.[92] Most electric acquisitions in 2004 took place with the purchase of specific generation assets; many companies strove to stabilize financial profiles through asset sales. In aggregate, almost 36 GW of generation, or nearly 6 percent of installed capacity, changed hands in 2004.[93]

TABLE 1–6.—POWER GENERATION ASSET DIVESTITURES BY INVESTOR-OWNED ELECTRIC UTILITIES, AS OF APRIL 2000

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

Source: EIA 2000 Update, Table 19.

Chapter 2—Context for the Task Force's Study of Competition in Wholesale and Retail Electric Power Markets

This chapter provides the context to the Task Force's study of competition in wholesale and retail electric power markets. For approximately 70 years, state and federal policymakers regulated the generation, transmission, and distribution of electric power as natural monopolies—it was considered inefficient to have multiple sources of generation, transmission, and distribution facilities serving the same customers. The traditional ''regulatory compact'' required an electric power utility to serve all retail customers in a defined area in exchange for the opportunity to earn a reasonable return on its investment. This approach is often called ''cost-based'' or ''cost-plus'' regulation.

Technological and regulatory changes as discussed in Chapter 1 negated the natural monopoly assumption for the most capital intensive segment of the industry—the generation of electric power. Federal and several state policymakers introduced competition to provide for an economically efficient allocation of resources within the industry's generation sector and to overcome the perceived shortcomings of traditional cost-based regulation. This chapter describes these shortcomings. It also discusses the role of price in guiding consumption and investment decisions in competitive markets.

This chapter highlights three issues that policymakers confronted as they considered introducing competition into wholesale and retail electric power markets. First, customers under historical cost-based regulation generally paid average prices calculated over an extended period of months or years that did not vary with their consumption or with variation in the cost of generating electric power. Thus, wholesale and retail customers did not receive economically accurate price signals to guide their consumption decisions. Similarly, suppliers did not receive economically accurate price signals to guide their short term sales of existing generation and long term generation. Second, regulators had historically encouraged local utilities to build or contract for sufficient generation to serve customers within their territories and they erected entry barriers to block entry by independent generators. These actions resulted in utilities owning nearly all generation assets within their own service territories. Under cost-based regulation, the regulator would set the price for electric power, thus addressing possible market power abuses that otherwise could occur with the monopoly utility structure. Third, certain physical realities associated with electricity generation constrain regulatory and market options in this industry. The inability to economically store electric power means that electricity must generally be consumed as soon as it is generated—supply must always exactly equal demand in real time. The delivery of electric power depends, however, upon availability and pricing of the regulated transmission grid. Thus, the physical realities of the transmission grid must be considered as competition develops in wholesale electric power markets.

The Task Force received many comments identifying or endorsing various studies on aspects of the costs and benefits of competition in wholesale and retail electric power markets, particularly the formation of Regional Transmission Organizations (RTOs) or similar entities.

Appendix C contains an annotated bibliography of these studies. Many of these studies, however, provide only limited insights into the effect of restructuring in wholesale and retail electric power markets. See Box 2–1 that describes a recent Department of Energy review of such studies. This Report addresses competition in various wholesale and retail markets regardless of whether they contain an RTO or similar entity.

Box 2–1: ''A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies''

By J. Eto, B. Lesieutre, and D. Hale, Prepared for the U.S. Department of Energy, December 2005

This paper provides a review of the state of the art in RTO Cost/Benefit studies and suggests methodological improvements for future studies. The study draws the following conclusions:

In recent years, government and private organizations have issued numerous studies

[90] FERC State of the Markets Report 2005 at 30–32.

[91] Announced in December 2003, Ameren closed its acquisition of Illinois Power Co. in September 2004. *Id.* at 31.

[92] In January 2004, Black Hills Corp announced the acquisition of Cheyenne Light, Fuel & Power from Xcel Energy. In July 2004, PNM Resources, the parent of Public Service Company of New Mexico, announced the intention to acquire TNP Enterprises, the parent of Texas New Mexico Power Company from a group of private equity investors. *Id.* at 31–32. In December 2004, Exelon announced its intent to merge with PSEG, a plan that would create the nation's largest utility company by generation ownership, market capitalization, revenues, and net income. *Id.* at 32.

[93] *Id.* at 30.

of the benefits and costs of Regional Transmission Organizations (RTOs) and other electric market restructuring efforts. Most of these studies have focused on benefits that can be readily estimated using traditional production-cost simulation techniques, which compare the cost of centralized dispatch under an RTO to dispatch in the absence of an RTO, and on the costs associated with RTO start-up and operation. Taken as a whole, it is difficult to draw definitive conclusions from these studies because they have not examined potentially much larger benefits (and costs) resulting from the impacts of RTOs on reliability management, generation and transmission investment and operation, and wholesale electricity market operation.

Existing studies should not be criticized for often failing to consider these additional areas of impact, because for the most part neither data nor methods yet exist on which to base definitive analyses. The primary objective of future studies should not be to simply improve current methods, but to establish a more robust empirical basis for ongoing assessment of the electric industry's evolution. These efforts should be devoted to studying impacts that have not been adequately examined to date, including reliability management, generation and transmission investment and operational efficiencies, and wholesale electricity markets. Systematic consideration of these impacts is neither straightforward nor possible without improved data collection and analysis.

A. Overview of Cost-Based Rate Regulation—Effect on Customer Prices and Investment Decisions

State policymakers imposed rate regulation on retail sales of electric power because allowing prices to be set by the monopolist was expected to lead to uneconomic results, namely higher prices with lower output. Regulators used cost-based regulation to meet state legal requirements to ensure sufficient output at reasonable prices for consumers.

1. Effect on Customer Prices

Retail prices for most customers, although different for each customer class, often were average prices calculated over an extended period of months or years that did not vary with their consumption or with the costs of generating electric power. These rates were stable and often only varied by season (*e.g.*, summer rates may be higher than winter rates). Although time-based rates and certain regulated products such as interruptible or curtailable services have been used within the electric power industry for decades, they have not been applied to the vast majority of retail customers. In addition, many argued that retail rate structures contain cross-subsidies among customer classes.[94]

2. Effect on Investment Decisions

The usual market-based signal for efficient investment into a market—prices that align consumer demand with generators' supply under given market conditions—is unavailable under cost-based rate regulation of retail electric power prices. Under cost-based rate regulation, utilities could decide when to add generation, but their recovery of their costs for these investments was dependent on state regulators agreeing that the generation was necessary and prudent. (Most state also imposed siting regulation on construction of major electric power facilities). Thus, it was long term planners and regulators that determined when generation would be built, and it was consumers who bore the cost of investment risks once they had been approved by the state regulators. Utilities were reluctant to take investment risks that might end up being unrecoverable if the regulators deemed their cost unreasonable. By far, the most important of these decisions was for generation investment which constitutes the substantial majority of the capital investment in the electric power industry. While the intent of cost-based rate regulation, was not simply to keep price down, the effect was sometimes to dampen investment in new capacity and innovation.[95] In making decisions, regulators struggled to strike the balance between reasonable rates and providing utilities with incentives to make necessary and sufficient investments.

Regulatory mistakes in setting rates too high or too low may lead to excessive or inadequate additions of new electric power generation and other forms of investment. If rates are set too high, utilities could earn a higher return on new generation investments than would be warranted by the cost of capital. The result could be overinvestment and overbuilding. Utilities also had little incentive to design new generation plants in a cost-effective manner, to the extent regulators were unlikely to identify and disallow excessive costs to be included in customer rates. At the same time, regulatory disallowances of some costs imposed risk on utility decisions to elicit capital and build new generation, and investors sought compensation for this risk when they supplied capital to utilities.[96]

Indeed, a 1983 Department of Energy analysis of electric power generation plant construction showed that electric utilities (which were regulated under a cost-based regulatory regime) had little ability to control the construction costs of coal and nuclear generation plants. During the 1970s and early 1980s, the cost range per megawatt to build a nuclear plant varied by nearly 400 percent and by 300 percent for coal plants. The DOE study showed that some companies were not competent to manage such large-scale, capital-intensive projects. In addition, there was a tendency to custom design these plants, as opposed to use of a basic design and then refining it.[97]

Box 2–2: Market Prices

Market prices reflect myriad individual decisions about prices at which to sell or buy. Market prices are a mechanism that equalizes the quantity demanded and the quantity supplied. Rising prices signal consumers to purchase less and producers to supply more. Falling prices signal consumers to purchase more and producers to supply less. Prices will stop rising or falling when they reach the new equilibrium price: the price at which the quantity that consumers demand matches the quantity that producers supply.

One alternative to traditional rate-of-return regulation is price cap regulation. Under this approach, the regulator caps the price a firm is allowed to charge.[98]

[94] Electricity Consumers Resource Council, Profiles in Electricity Issues: Cost-of-Service Survey (Mar. 1986).

[95] *See e.g. The Economics and Regulation of Antitrust,* at 6–7.

[96] In the academic literature, the risk of utility overinvestment has been explained by the Averch-Johnson Effect. The Averch-Johnson Effect reflects that ''a firm that is attempting to maximize profits is give, by the form of regulation itself, incentives to be inefficient. Furthermore, the aspects of monopoly control that regulation is intended to address, such as high prices, are not necessarily mitigated, and could be made worse, by the regulation.'' KENNETH E. TRAIN, OPTIMAL REGULATION 19 (1991). The Averch-Johnson Effect also predicts that if a regulator attempts to reduce a firm's profits by reducing its rate of return, the firm will have an incentive to further increase its relative use of capital. *Id.* at 56. Thus, the most obvious regulatory control within cost-base rate regulation creates further distortions. The Averch-Johnson Effect is sometimes thought to explain why a regulated firm is led to ''gold plate'' its facilities, *i.e.* incur excessive costs so long as those expenses can be capitalized.

[97] U.S. Dept. of Energy, *The Future of Electric Power in America: Economic Supply for Economic Growth,* June, 1983 (DOE/PE–0045).

[98] Under price cap regulation, a firm can theoretically ''produce with the cost-minimizing input mix [and] invest in cost-effective innovation.'' Train at 318. However, this dynamic only occurs where the price cap is fixed over time and the utility receives the benefit of cost reductions and cost-effective innovations. Further, the benefit of this increased efficiency ''accrues entirely to the firm: consumers do not benefit from the production efficiency.'' *Id.* Where the price cap is adjusted over time, firms are induced to engage in strategic behavior. Additionally, ''if, as * * * expected, the review of price caps is conducted like the price

This alternative may remedy some of the incentive problems of cost-base regulation. Another alternative is Integrated Resource Planning, which provided that choices about the building of new generation would be controlled by the regulator. Even with this oversight mechanism, regulators had few reference points to determine prudence in the choices that the builder made about design, efficiency, and materials.

In part, the struggles of regulators to ensure adequate supplies of power at reasonable rates led policy makers to examine whether competition could provide more timely and efficient incentives for what to consume and build. Advances in technology negated the assumption that generation is a natural monopoly, and thus set the stage for price and competition to provide a market entry signal, although transmission and distribution would continue to be regulated.

B. Competition in Wholesale and Retail Electric Power Markets—The Role of Price

With competition, the price of a commodity such as electric power generally reflects suppliers' costs and consumers' willingness to pay. The price signals the relative value of that commodity compared to other goods and services. How much a supplier will produce at a given price is determined by many things, including (in the long run) how much it must pay for the labor it hires, the land and resources it uses, the capital it employs, the fuel inputs it must purchase to generate the electric power, the transmission it must use to deliver the electric power to end users, and the risks associated with its investment. Consumers' overall willingness to pay for a product also is determined by a large variety of factors, such as the existence and prices of substitutes, income, and individual preferences.

1. Price Affects Customer Consumption

Price changes signal to customers in wholesale and retail markets that they should change their decisions about how much and when to consume electric power. Price increases generally provide a signal to customers to reduce the amount they consume. The dampening effect on price of a reduction in consumption helps consumers safeguard themselves against a supplier that may seek to exercise market power by increasing prices. By contrast, lower prices may encourage some customers to consume more than they would have at higher prices. Price changes thus play an important economic function by encouraging customers and suppliers to respond to changing market conditions. In the electric power industry, consumer's price responsiveness is often referred to as ''demand response.'' [99]

The primary objective to incorporate price-based signals into wholesale and retail electric power markets is to provide consumers with price signals that accurately reflect the underlying costs of production. These signals will improve resource efficiency of electric power production due to a closer alignment between the price that customers pay for and the value they place *on* electricity. In particular, by exposing customers (some or all) to prices based on marginal production costs, resources can be allocated more efficiently.[100] Flat electricity prices based on average costs can lead customers to ''over-consume—relative to an optimally efficient system in hours when electricity prices are higher than the average rates, and under-consume in hours when the cost of producing electricity is lower than average rates.'' [101] Exposure of customers to efficient price signals also has the benefit of increasing price response during periods of scarcity and high prices, which can help moderate generator market power and improve reliability.

When customers have many close substitutes for a particular good, a relatively small price increase will result in a relatively large reduction in how much they consume. For example, if natural gas were a very good substitute for electric power at comparable prices, then even a relatively small increase in the price of electric power could persuade many consumers to switch in part or entirely to natural gas, rather than electricity. To induce those consumers to return to using electricity, electricity prices would not need to fall by very much. However, when there are no close substitutes for electric power, prices may have to rise substantially to reduce consumption in order to restore the balance between the quantity supplied and the quantity demanded.

A substantial body of empirical literature has shown that, even if the retail price of electricity increases relatively quickly and sharply, the short-run consumption of electricity does not decline much. In other words, short-run demand for electricity is very inelastic. *See* Box 2–3. This inability to substitute other products for electricity in the short run means that changes in supply conditions (price of input fuels, etc.) are likely to cause wider price fluctuations than would be the case if customers could easily reduce their demand when prices rise. Furthermore, electric power has few viable and economic substitutes for key end-uses such as refrigeration and lighting and thus the consequences for supply shortfalls can be significant.[102] In the long run, this effect may be somewhat muted as, with time, electricity customers may have more ability to adjust their consumption in response to price changes.

Box 2–3: Demand Elasticity

The desire and ability of consumers to change the amount of a product they will purchase when its price increases is known as the price elasticity of that product. The price elasticity of demand is the ratio of the percent change in the quantity demanded to the percent change in price. That is, if a 10 percent price increase results in a 5 percent decrease in the quantity demanded, the price elasticity of demand equals −0.5 (−5%/10%). If the ratio is close to zero demand is considered ''inelastic'', and demand is more ''elastic'' as the ratio increases, especially if the ratio is greater than −1. Short-run elasticities are typically lower than long-run elasticities.

Experience in New York, Georgia, California, and other states and pricing experiments have demonstrated that customers have adjusted their consumption, and are responsive to

reviews under cost-base rate regulation, then the distinction blurs between price-cap regulation and cost-base rate regulation.'' *Id* at 319.

[99] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005,* February 2006 (DOE EPAct Report). The DOE EPAct Report discusses the benefits of demand response in electric power markets and makes recommendations to achieve these benefits.

[100] There is a substantial literature on setting rates based on marginal costs in the electric sector. See for example, M. Crew and P. Kleindorfer, *Public Utility Economics.* St. Martin's Press: New York, 1979 and B. Mitchell, W. Manning, and J. Paul Acton, *Peak-Load Pricing.* Ballinger: Cambridge, 1978. Other papers suggest that setting rates based on marginal costs will result in a misallocation of resources (*see* Borenstein, S., *The Long-Run Efficiency of Real-Time Pricing,* ENERGY JOURNAL, Vol. 26, No. 3, 2005). Nevertheless, the literature also indicates that marginal cost pricing may result in a revenue shortfall or excess, and standard rate-making practice is to require an adjustment (presumably to an inelastic component) to reconcile with embedded cost-of-service. Various rate structures to accomplish marginal-cost pricing include two-part tariffs (*see* Viscusi, Vernon, and Harrington, *Economics of Regulation and Antitrust,* MIT Press, 2000) and allocation of shortfalls to rate classes.

[101] DOE EPAct Report, p. 7.

[102] Estimates of the total costs in the United States due to August 14, 2003 blackout range between $4 billion and $10 billion. ELCON, *The Economic Impacts of the August 2003 Blackout,* February 2, 2004.

short-run price changes (*i.e.*, have a non-zero short-run price elasticity of demand). Georgia Power's Real Time Pricing (RTP) tariff option has found that industrial customers who receive RTP based on an hour-ahead market are somewhat price-responsive (short-run price elasticities ranging from approximately −0.2 at moderate prices, to −0.28 at prices of $1/kWh or more). Among day-ahead RTP customers, short-run price elasticities range from approximately −0.04 at moderate prices to −0.13 at high prices. Similar elasticities were found in the National Grid RTP pricing program. A critical peak pricing experiment in California in 2004 determined that small residential and commercial customers are price responsive and will make significant reductions in consumption (13 percent on average, and as much as 27 percent when automated controls such as controllable thermostats were installed) during critical peak periods. In addition, the California pilot found that most customers who were placed on the CPP tariffs had a favorable opinion of the rates and would be interested in continuing in the program.[103]

The ability of a customer to respond to prices requires the following conditions: (1) That time-differentiated price signals are communicated to customers, (2) that customers have the ability to respond to price signals (*e.g.*, by reducing consumption and/or turning on an on-site generator), and (3) that customers have interval meters (*i.e.*, so the utility can determine how much power was used at what time and bill accordingly).[104] Most conventional metering and billing systems are not adequate for charging time-varying rates and most customers are not used to considering price changes in making electricity consumption decisions on a daily or hourly basis.

2. Supplier Responses Interact With Customer Demand Responses to Drive Production

Generation supply responses are equally important in determining an appropriate equilibrium market price. The extent of supply responses will depend on the cost of increasing or decreasing output. Generally, the longer industry has to adjust to a change in demand, the lower will be the cost of expanding that output. With more time, firms have more opportunity to change their operations or invest in new capacity.

If the cost of increasing production is small, then a relatively small price increase may be enough to encourage existing producers to increase their production levels to provide additional supply in response to increased demand. If the cost of increasing electricity capacity is high, however, existing suppliers will not increase their production without a very strong price signal. In that case, customers would have to pay significantly higher prices to obtain additional supply. Additionally, if suppliers are already producing as much electric power as they can, increased demand can be met only from new capacity, and suppliers must be confident that prices will remain high enough for long enough to justify building a new generating plant.

These supply decisions are complicated because electric power cannot be stored economically, thus there are generally no inventories in electricity markets. Therefore, electricity generation must always exactly match electricity consumption.[105] The lack of inventories means that wholesale demand is completely determined by retail demand. Moreover, any distant generation must ''travel'' over a transmission system with its own limiting physical characteristics.[106] Transmission capability is required to allow customers access to distant generation sources. The transmission system is complicated by the fact that the dynamics of the AC transmission grid create network effects and can produce positive externalities (depending on the method used in accounting for transmission costs).[107] That is to say, where transmission users are not charged for the congestion impacts of their use patterns, that user's actions can cause costs to other users—costs which the causal party is not obligated to pay. This dynamic can distort the effect of price signals on dispatch efficiencies.

Moreover, aggregate retail demand fluctuates throughout the day, with higher demand during the day than at night. Fluctuating demand means that the transmission operator must have sufficient capacity to equal or exceed customer demand in real-time. Load serving entities (those entities that deliver power to meet demand or ''load'') must supply or procure sufficient capacity and energy (either in long-term contracts or short-term ''spot'' market purchases) to meet these varying loads. The costs of generating electricity are also highly variable, leading to wide disparity between the costs of generating electricity from generation plants that operate around-the-clock versus the cost of those that generate only during peak periods.

In any case, a higher price signals a profit opportunity, attracting resources where they are needed. If customer demand decreases in response to rising prices, prices are likely to fall, all else equal. In that circumstance, falling demand signals suppliers to reduce the amount of electric power that they supply. Suppliers will reduce their generation to meet the new, lower level of consumer demand, and will not be inclined to consider any new capacity increases.

3. Customer and Supplier Behavior Responding to Price Changes in Markets

In sum, the combined impact of consumers' and suppliers' responses to changed market conditions will produce a new market equilibrium price. Current prices must change when they create an imbalance between the quantity demanded and the quantity supplied. For example, when demand spikes, short-run prices might have to swing sharply higher to provide incentives for short-run supply increases. However, consumers do not have very many good substitutes for electric power, and suppliers usually cannot increase output instantly or transport distant available generation to increase the quantity supplied to a market. Even if higher prices give consumers and producers incentives to change their behavior, they may have little ability to do so in the short term. Over much longer time frames, however, both consumers and producers have more options to react to higher prices. The result is that long-run price increases usually will be much smaller than the short-run price increases needed to induce additional generation.

Chapter 3—Competition in Wholesale Electric Power Markets

A. Introduction and Overview

Congress required the Task Force to conduct a study of competition in wholesale electric power markets. Wholesale markets involve sales of electric power among generators, marketers, and load serving entities (e.g., distribution utilities) that

[103] Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot,* Final Report, March 16, 2005, *available at http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005–03–24_SPP_FINAL_REP.PDF.* Customers on a similar CPP program at Gulf Power also have high satisfaction with the program, which incorporates automated response to CPP events.

[104] EEI; PEPCO cautions that many customers, particularly residential and commercial customers, are relatively inflexible in responding to price changes due to constraints imposed by their operations and equipment.

[105] APPA.

[106] Alcoa.

[107] TAPS.

ultimately resell the electric power to end-use customers (e.g., residential, commercial, and industrial customers). Prior to the introduction of competition, vertically integrated utilities with excess electric power sold it to other utilities and to wholesale customers such as municipalities and cooperatives that had little or no generating capacity of their own. The Federal Energy Regulatory Commission (FERC) and its predecessor agency (the Federal Power Commission) regulated the prices, terms and conditions of interstate wholesale sales by investor-owned utilities. The desire of wholesale purchasers for access to competitive sources of electric power was a fundamental impetus to the opening of the generation sector to competition.[108]

Effective competition ensures an economically efficient allocation of resources. Congress in the Energy Policy Act of 1992 (EPACT 92) determined that competition in wholesale electric power markets would benefit from two changes to the traditional regulatory landscape: (1) Expansion of FERC's authority to order utilities to transmit, or ''wheel,'' electric power on behalf of others over their owned transmission lines; and (2) elimination of entry barriers so non-utility entry could occur. The former change permitted wholesale customers to purchase supply from distant generators and the latter change provided customers with competitive alternatives from independent entrants.[109]

As described in Chapter 2, an important component of effective market operation is customer response to prices. The demand for wholesale power, however, is derived entirely from consumption choices at the retail level. The lack of electric power inventories only intensifies the direct link between wholesale and retail electric power markets. Yet state regulators set the prices for retail customers. State regulators generally have treated wholesale rates as an input into retail prices. But states often set retail rates that dilute the direct impact of the price of wholesale power on retail prices.[110] Thus, retail consumption decisions have been guided by prices, terms, and conditions that often do not directly reflect the wholesale price to purchase the electric power or the cost generators incurred to produce it.

This price disconnect is heightened by the fact that, if competition is to allocate resources in an economically efficient manner, customers must have access to a sufficient number of competing suppliers either via transmission or from new local generation.[111] But one of the shortcomings of cost-based rate regulation was its inability to provide incentives for investors to make economically efficient decisions concerning when, where, and how to build new generation.

Thus, the question is whether competition in wholesale markets has resulted in sufficient generation supply and transmission to provide wholesale customers with the kind of choice that is generally associated with competitive markets. In other words, has competition in wholesale electric power markets resulted in an economically efficient allocation of resources? The answer to this question is difficult to derive because each region was at a different regulatory and structural starting point upon Congress' enactment of the Energy Policy Act of 1992. These differences make it difficult to single out the determinants of consumption and investment decisions and thus make it difficult to evaluate the degree to which more competitive markets have influenced such decisions. Even the organized exchange markets have different features and characteristics. For example, some regions already had tight power pools, others were more disparate in their operation of generation and transmission. Some regions had higher population densities and thus more tightly configured transmission networks than did others. Some regions had access to fuel sources that were unavailable or less available in other regions (e.g., natural gas supply in the Southeast, hydro-power in the Northwest). Some regions operate under a transmission open-access regime that has not changed since the early days of open access in 1996, while other regions have independent provision of transmission services and organized day-ahead exchange markets for electric power and ancillary services.

This chapter discusses the impact of competition for generation supply on the ability of wholesale customers to make economic choices among suppliers and for suppliers to make economic investment decisions. The chapter addresses how entry has occurred in several regions with different forms of competition (e.g., the Midwest, Southeast, California, the Northwest, Texas, and the Northeast). This chapter also discusses how long-term purchase and supply contracts, capital requirements, regulatory intervention, and transmission investment affect supplier and customer decisions. The chapter concludes with observations on various regional experiences with wholesale competition. These observations highlight the trade-offs involved with various policy choices used to introduce competition.

B. Background

Congress enacted the EPACT 92 to jump start competition in the electric power industry. One of the stated purposes of the EPACT 92 was ''to use the market rather than government regulation wherever possible both to advance energy security goals and to protect consumers.'' [112] Policy makers recognized that vertically integrated utilities had market power in both transmission and generation—that is they owned all transmission and nearly all generation plants within certain geographic areas. Congress, therefore, enhanced FERC's authority to order utilities, case-by-case, to transmit power for alternative sources of generation supply.

Today, vertically integrated utilities that operate their transmission systems generally offer transmission service under the terms of the standard Open Access Transmission Tariff (OATT) adopted by FERC in Order No. 888. The OATT requires a utility to offer the same level of transmission service, under the same terms and conditions and at the same rates that it provides to itself. Vertically integrated utilities (also referred to here as the transmission provider) offer two types of long-term transmission service under the OATT: network integration transmission service (network service) and point-to-point transmission service. *See* Box 3–1 for a description of both types of transmission service. For both services, the price has been predictable and stable over the long term.[113]

[108] *U.S.* v. *Otter Tail Power Company,* 410 U.S. 366 (1973) (the United States sued a vertically integrated utility for refusal to deal with the Town of Elbow Lake, MI, a town that was seeking alternative sources of wholesale power for a planned municipal distribution system).

[109] *See* EPACT 92 House Report. H.R. No. 102–474(I) at 138.

[110] *See infra* Chapter 1.

[111] *See, e.g.,* U.S. Gen. Accounting Office, GAO–03–271, LESSONS LEARNED FROM ELECTRIC INDUSTRY RESTRUCTURING 21 (2002) (''Increasing the amount of competition requires structural changes within the electric industry, such as allowing a greater number of sellers and buyers of electricity to enter the market'').

[112] H.R. No. 102–474(I) at 133.

[113] The demand charge for long-term point-to-point transmission service is known in advance. For network service, the transmission customer pays a load ratio share of the transmission provider's FERC-approved transmission revenue requirement. Thus, even if redispatch to relieve transmission congestion occurs and the costs are charged to

Continued

Box 3–1: How Transmission Services Are Provided Under the OATT

OATT contracts can be for point-to-point (PTP) or ''network'' transmission service. Network integration transmission service allows transmission customers (*e.g.*, load serving entities) to integrate their generation supply and load demand with that of the transmission provider.

A transmission customer taking network service designates ''network resources,'' which includes all generation owned, purchased or leased by the network customer to serve its designated load, and individual network loads to which the transmission provider will provide transmission service. The transmission provider then provides transmission service as necessary from the customer's network resources to its network load. The customer pays a monthly charge for the basic transmission service, based on a ''load ratio share'' (*i.e.*, the percentage share of the total load on the system that the customer's load represents) of the transmission-owning and operating utility's ''revenue requirement'' (*i.e.*, FERC-approved cost-of-service plus a reasonable rate of return).

In addition to this basic charge, some additional charges may be incurred. For example, when a transmission customer takes network service, it agrees to ''redispatch'' its generators as requested by the transmission provider. Redispatch occurs when a utility, due to congestion, changes the output of its generators (either by producing more or less energy) to maintain the energy balance on the system. If the transmission provider redispatches its system due to congestion to accommodate a network customer's needs, the costs of that redispatch are passed through to all of the transmission provider's network customers, as well as to its own customers, on the same load-ratio share basis as the basic monthly charge.

Also, the transmission provider must plan, construct, operate and maintain its transmission system to ensure that its network customers can continue to receive service over the system. To the extent that upgrades or expansions to the system are needed to maintain service to a network customer, the costs of the upgrades or expansions are included in the transmission-owning utility's revenue requirement, thus impacting the load-ratio share paid by network customers.

Point-to-point transmission service, which is available on a firm or non-firm basis and on a long-term (one year or longer) or short-term basis, provides for the transmission of energy between designated points of receipt and designated points of delivery. Transmission customers that take this kind of service specify a contract path. A customer taking firm point-to-point transmission service pays a monthly demand charge based on the amount of capacity it reserves. Generally, the demand charge may be the higher of either the transmission provider's embedded costs to provide the service, or the incremental costs of any system expansion needed to provide the service. Also, if the transmission system is constrained, the demand charge may reflect the higher of the embedded costs or the transmission provider's ''opportunity'' costs, with the latter capped at incremental expansion costs.

The comments submitted in response to the Task Force's request raised several concerns as to transmission-dependent customers' access to alternative generator suppliers via OATTs. In particular, some commenters noted that there is a continued possibility of transmission discrimination in their region, and that ability for transmission suppliers to discriminate can deny transmission-dependent customers access to alternative suppliers.[114] The commenters conclude that transmission discrimination can increase delivery risk because purchasers feared that their transmission transactions might be terminated for anticompetitive reasons by their vertically integrated rival, were they to purchase generation from a generator who is not affiliated with the transmission provider. The fact that electricity cannot be stored economically and electricity demand is very inelastic in the short term heightens the ill-effects of this delivery risk.

One response to this risk is to turn over operation of the transmission grid in a region to an independent operator, like the ones that now operate in New England, New York, the Mid-Atlantic, Texas, and California (''organized markets''). With the market design in these regions, there is no risk that a wholesale customer will not be able to deliver power to its retail customers (although they remain exposed to price risk).[115] See Box 3–2 for a discussion of how transmission is provided in organized wholesale markets.

Box 3–2: How Transmission Is Priced in an ISO or RTO

ISOs and RTOs (hereinafter RTOs) provide transmission service over a region under a single transmission tariff. They also operate organized electricity markets for the trading of wholesale electric power and/or ancillary services. Transmission customers in these regions schedule with the RTO injections and withdrawals of electric power on the system, instead of signing contracts for a specific type of transmission service with the transmission owner under an OATT.

The pricing for transmission service is substantially different in these regions than under the OATT. RTOs generally manage congestion on the transmission grid through a pricing mechanism called Locational Marginal Pricing (LMP). Under LMP, the price to withdraw electric power (whether bought in the exchange market or obtained through some other method) at each location in the grid at any given time reflects the cost of making available an additional unit of electric power for purchase at that location and time. In other words, congestion may require the additional unit of energy to come from a more expensive generating unit than the one that cannot be accessed due to the system congestion. In the absence of transmission congestion, all prices within a given area and time are the same. However, when congestion is present, the prices at various locations typically will not be the same, and the difference between any two locational prices represents the cost of transmission system congestion between those locations.

All existing organized markets have a uniform price auction or exchange to determine the price of electric power. Because of this variation in exchange prices at different locations, a transmission customer is unable to determine beforehand the price for electric power at any location because congestion on the grid changes constantly. To reduce this uncertainty, RTOs make a financial form of transmission rights available to transmission customers, as well as other market participants. Generally known as financial transmission rights (FTRs), they confer on the holder the right to receive certain congestion payments. Generally, an FTR allows the holder to collect the congestion costs paid by any user of the transmission system and collected by the RTO for electric power delivered over the specific path. In short, if a transmission customer holds an FTR for the path it takes service over, it will pay on net either no congestion charges (if the FTR matches the path exactly) or less congestion charges (if the FTR partially matches), providing a financial ''hedge'' against the uncertainty.

In general, FTRs are now available for one-year terms (or less), and are allocated to entities that pay access charges or fixed transmission rates. Pursuant to EPACT 05, FERC has begun a rulemaking to ensure the availability of long-term FTRs.

In regions with RTOs, wholesale electricity can be bought and sold through the use of negotiated bilateral contracts, through ''standard commercial products'' available in all regions, and through various products offered by the organized exchange market. For bilateral contracts, the contract can be individually negotiated and have terms and conditions unique to a single transaction. Standard products are available through brokers

customers, or expansion is necessary and the costs of the expansion are added to the revenue requirement, the distribution of the costs over the whole system has allowed the charges to individual customers to remain relatively stable. Customers who take either kind of service have a right to continue taking service when their contract expires, although point-to-point customers may have to pay a different rate (up to the maximum rate stated in the transmission provider's tariff) for that service if another customer offers a higher rate.

[114] APPA, TAPS. *See also* Midwest Stand Alone Transmission Companies.

[115] Prior to wholesale competition, several of the regions listed had ''power pools'' of utilities that undertook some central economic dispatch of plants and divided the cost savings among the vertically integrated utility members.

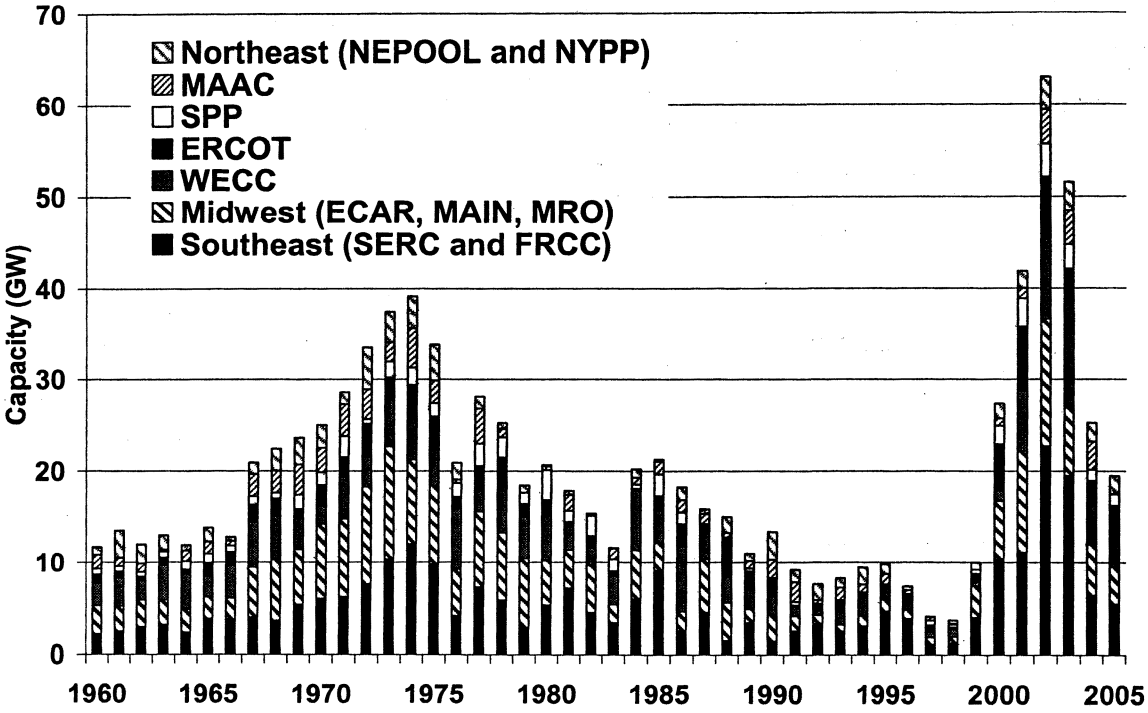
and over-the-counter (OTC) exchanges such as the NYMEX and Intercontinental Exchange (ICE).[116] Standard products have a standard set of specifications so that the main variant is price. Finally, there are organized exchange markets operated by the RTOs. In addition to offering transmission services, these organized exchange markets offer various products including electric power and ancillary services. Electric power markets typically involve sales of electric power in both hour-ahead and day-ahead markets.

Ancillary services include various categories of generation reserves such as spinning and non-spinning reserves in addition to Automatic Generation Control (AGC) for frequency control. The question remains, however, whether the price signals described in Chapter 2 have functioned to elicit the consumption and investment decisions that were expected to occur with wholesale market competition? The next section reviews generation entry in different regions.

C. Generation Investment Has Varied by Region Since Competition Increased in Wholesale Electric Power Markets

Since the adoption of open access transmission and the growth of competition, the amount of new generation investment has varied significantly by region. Figure 3–1 shows the overall pattern of new investment, broken down by region. A substantial amount of new investment has occurred in the Southeast, Midwest, and Texas. Other regions have not experienced as much investment. Wholesale customers obtain transmission services under different pricing formats in each region. Moreover, the regions that operate exchange markets for electric power and ancillary services use different forms of locational pricing, price mitigation, and capacity markets.

Figure 3-1: U.S. Electric Generating Capacity Additions (1960 – 2005)



Source: FERC Analysis of Platts PowerDat Data

These regional differences provide some insight into the impact of different policy choices on the challenge to create markets with sufficient supply choices to support competition and to allocate resources efficiently.

1. Midwest

Wholesale Market Organization: In 2004, the Midwest RTO began providing transmission services to wholesale customers in its footprint. On April 1, 2005, the MISO commenced its organized electric power market operations. Prior to this time, wholesale customers obtained transmission under each utility's OATT and there were no centralized electric power exchange markets.

New Generation Investment: The Midwest experienced a wholesale price spike during the summer of 1998.[117] An

[116] Companies can also limit their exposure to price swings through financial instruments rather than contracts for physical delivery of electricity. Such contracts are essentially a bet between two parties as to the future price level of a commodity. If the actual price for power at a given time and location is higher than a financial contract price, Party A pays Party B the difference; if the price is lower, Party B pays Party A the difference. In fact, in the United States electricity markets, such agreements are sometimes called ''contracts for differences''. Purely financial contracts involve no obligation to deliver physical power. In this report, we discuss contracts for physical delivery rather than financial contracts, unless otherwise noted.

[117] Fed. Energy Regulatory Comm'n, *Staff Report to the Fed. Energy Regulatory Comm'n on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998* (1998).

increase in demand due to unusually hot weather combined with unexpected generation outages created a rapid spike in wholesale prices. A significant amount of new generation was built in response to the price spike as shown in Table 3–1. For example, from January 2002 through June 2003, the Midwest added 14,471 MW in capacity.[118]

Most of the new generation was gas-fired, even though the region as a whole relies primarily on coal-fired generation.[119] More-recent entry has in fact been coal fired, in part because of rising natural gas prices.[120] The results of this entry and the subsequent drop in wholesale power prices have included: (1) merchant generators in the region declaring bankruptcy and (2) vertically-integrated utilities returning certain generation assets from unregulated wholesale affiliates to rate-base.

2. Southeast

Wholesale Market Organization: Wholesale customers in the region obtain transmission under each utility's OATT (*e.g.*, Entergy or Southern Companies). There are no centralized electric power markets specific to the region.

New Generation Investment: The Southeast's proximity to natural gas sources in the Gulf of Mexico and pipelines to transport that natural gas have made natural gas a popular fuel choice for those building plants in the region. The Southeast has seen considerable new generation construction as shown in Figure 3–1. More than 23,000 MW of capacity were added in the Southern control area between 2000 and 2005,[121] and several generation units owned by merchants or load-serving entities have been built in the Carolinas in the past few years. A significant portion of the new generation in the Southeast was non-utility merchant generation. A number of merchant companies that built plants in the 1990s have sought bankruptcy protection. Often, the plants of the bankrupt companies have been purchased by local vertically-integrated utilities and cooperatives, such as Mirant's sale of its Wrightsville plant to Arkansas Electric Cooperative Corporation and NRG's sale of its Audrain plant to Ameren.[122] Even apart from bankruptcies, some independent power producers have withdrawn from the region.

3. California

Wholesale Market Organization: The California ISO began operation in 1998 to provide transmission services. Concurrently, a separate Power Exchange (PX) operated electric power exchanges. Subsequent to the 2000–01 energy crisis, the California dissolved the PX.

New Generation Investment: Even prior to the California energy crisis, California was dependent on imported electric power from neighboring states. Much of the generation capacity for Southern California was built a substantial distance away from the population it serves, making the region heavily-dependent upon transmission. In the past few years, much of the generation in California has operated under long-term contracts negotiated by the State during the energy crisis. Since 2000–01, demand has increased in California, but construction of local generation has not kept pace. Over 6,000 MW of new generation capacity has entered California in 2002–03, but very little of it was built in congested, urban areas like San Francisco, Los Angeles and San Diego.[123] The commenters acknowledged that significant new generation has been announced or built in California in the past few years, but most of the projects have been in Northern California.[124] In the past five years, transmission investment has improved links between Southern and Northern California and accessible generation investment in the Southwest more generally has increased.

4. The Northeast

a. New England

Wholesale Market Operation: The New England ISO (ISO–NE) provides transmission services as well as operating a centralized electric power market. Under the electric power pricing mechanism adopted by the New England ISO, the expensive units used to maintain resource adequacy in some local areas are often not eligible to set the market clearing price because of the ISO's use of must-run reliability contracts. Rather, the cost of these high-priced units is spread across the region to all users.

New Generation Investment: Much of the generation in New England has been built in less populated areas of the region, such as Maine, but much of the demand for power is in southern New England. From January 2002 through June 2003, ISO–NE added 4159 MW in capacity.[125]

Capacity additions in 2004 were less than in the two previous years. In 2004, four generation projects came on line. Generation retirements in 2004 totaled 343 MW, of which 212 MW are deactivated reserves.

Demand growth in the organized New England markets has led to ''load pockets,'' areas of high population density and high peak demand that lack adequate local supply to meet demand and transmission congestion prevents use of distant generation units to meet local demand. These pockets have not seen entry of generation to meet that demand. Transmission has not always been adequate to bridge this gap. In general, New England needs new generation in the congested areas of Boston and Southwest Connecticut or increased transmission investment to reduce congestion.

Moreover, the need for more supply in these load pockets is not reflected in high locational prices that would signal investment.[126] ISO–NE has recognized this issue and in 2003, it implemented a temporary measure known as Peaking Unit Safe Harbor (PUSH). PUSH enabled greater cost recovery for high-cost, low-use units in designated congestion areas, although PUSH units still may not be able to recover completely all their fixed costs.[127] ISO–NE also seeks to establish a locational capacity product that will project the demand three years in advance and hold annual auctions to purchase power resources for the region's needs. This proposal is part of a settlement pending before FERC. ISO–NE originally proposed a different market model called Locational Installed Capacity (LICAP). That model was opposed by a variety of stakeholders.[128]

b. New York

Wholesale Market Operation: The New York ISO (NYISO) provides transmission services as well as operating a centralized electric power market. On the one hand, NYISO uses price mitigation to guard against wholesale price spikes but, on the other, it allows high cost generators to be included in marginal location prices.

New Generation Investment: New York has traditionally built generation

[118] FERC State of the Markets Report 2004 at 109.

[119] FERC State of the Markets Report 2004 at 50.

[120] FERC State of the Markets Report 2005 at 77.

[121] Southern Companies.

[122] *See* Fitch Ratings, Wholesale Power Market Update (Mar. 13, 2006), *available at http://www.fitchratings.com/corporate/sectors/special_reports.cfm?sector_flag=2&marketsector=1&detail=&body_content=spl_rpt.*

[123] FERC State of the Markets Report 2005 at 69; FERC State of the Markets Report 2004 at 41–43.

[124] California ISO.

[125] FERC State of the Markets Report 2004 at 109.

[126] FERC State of the Markets Report 2005 at 83.

[127] FERC State of the Markets Report 2004 at 36.

[128] Press Release, ISO New England, ISO New England Announces Broad Stakeholder Agreement on New Capacity Market Design (Mar. 6, 2006), *available at http://www.iso-ne.com/nwsiss/pr/2006/march_6_settlement_filing.pdf.*

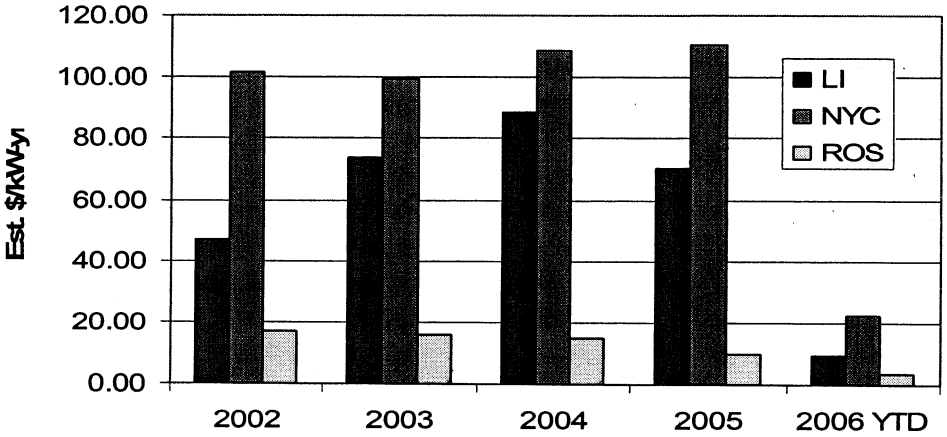
in less populated areas and moved it to more populated areas. For example, the New York Power Authority was responsible for getting hydroelectric power from the Niagara Falls area into more congested areas of the state. From January 2002 through June 2003, NYISO added 316 MW in capacity.[129] Three generating plants with a total summer capacity of 1,258 MW came on line in 2004. Three plants totaling 170 MW retired in 2004.[130]

Transmission constraints are therefore a concern, and currently, transmission constraints in and around New York City limit competition in the city and lead to more use of expensive local generation, thereby raising prices. NYISO uses price mitigation that seeks to avoid mitigating high prices that are the result of genuine scarcity, though NYISO has separate mitigation rules for New York City. In an effort to lessen distortion of market signals, NYISO includes the cost of running generators to serve load pockets in its calculation of locational prices. Thus, potential entrants get a more accurate price signal regarding investment in the load pocket.

In a further effort to spur new capacity construction, NYISO also sets a more generous ''reference price'' for new generators in their first three years of operation.[131] (Bids above the reference prices may trigger price mitigation.) Unlike New England, New York is seeing new generation investment in a congested area. Approximately 1,000 MW of new capacity is planned to enter into commercial operation in the New York City area in 2006. The fact that New York is better able than New England to match locational need with investment is likely due to clearer market price signals in New York, both in energy markets and capacity markets.

The effect of load pockets on prices are shown in Figure 3–2, which estimates the annual value of capacity based on weighted average results of three types of auctions run by the NYISO. Capacity prices are higher in the tighter supply areas of NYC and Long Island.

Figure 3-2: Estimate of Annual NY Capacity Values - All Auctions



c. PJM

Wholesale Market Operation: The PJM Interconnection provides transmission services as well as operating a centralized electric power market. PJM has both energy and capacity markets. PJM's energy market has locational prices. FERC recently approved the concept of PJM's proposal to shift to locational prices in its capacity markets.[132] The locational capacity market has not yet been implemented.

New Generation Investment: PJM capacity includes a broad mix of fuel types. Recent PJM expansion has added significant low-cost coal resources to PJM's overall generation mix. From January 2002 through June 2003, PJM added 7458 MW in capacity.[133] Capacity additions in 2004 were lower than in the two previous years. In 2004, 4,202 MW of new generation was completed in PJM. During the year, 78 MW of generation was mothballed and 2,742 MW was retired.[134]

Like other areas, PJM depends on transmission to move power from the areas of low-cost generation to the areas of high demand. In PJM, the flow is generally from the western part of PJM, an area with significant low-cost coal-fired generation, to eastern PJM. The easternmost part of PJM is limited by a set of transmission lines known as the Eastern Interface, which at times limits the deliverability of generation from the west. This means that higher-cost generation must be run in the eastern region to meet local demand. Within the eastern region, there are also areas of still-more-limited transmission. As a result of these kinds of transmission limitations, generation in some areas that is not economical to run is being given reliability must-run (RMR) contracts to prevent it from retiring and possibly reducing local reliability.[135] Recently, three utilities in PJM have proposed major transmission expansions to increase capacity for moving power from into eastern parts of PJM.[136]

[129] FERC State of the Markets Report 2004 at 109.

[130] FERC State of the Markets Report 2005 at 97.

[131] FERC State of the Markets Report 2004 at 39.

[132] Intial Order on Reliability Pricing Model, 115 FERC ¶ 61,079, *3 (2006).

[133] FERC State of the Markets Report 2004 at 109.

[134] FERC State of the Markets Report 2005 at 112.

[135] *Id.* at 188.

[136] American Electric Power proposes to build a new 765-kilovolt (kV) transmission line stretching from West Virginia to New Jersey, with a projected in-service date of 2014. AEP Interstate Project Summary, *available at http://www.aep.com/newsroom/resources/docs/AEP_Interstate ProjectSummary.pdf.* Allegheny Power proposes to construct a new 500 kV transmission line, with a targeted completion date of 2011, which will extend from southwestern Pennsylvania to existing substations in West Virginia and Virginia and continue east to Dominion Virginia Power's Loudoun Substation. Allegheny Power Transmission Expansion Proposal, *available at http://www.alleghenypower.com/TrAIL/TrAIL.asp.* More recently, Pepco has proposed to build a 500-kv transmission line from Northern Virginia, across the Delmarva Penninsula and into New Jersey.

5. Texas

Wholesale Market Operation: The Electric Reliability Council of Texas (ERCOT) manages the scheduling of power on an electric grid consisting of about 77,000 megawatts of generation capacity and 38,000 miles of transmission lines. ERCOT also manages financial settlement for market participants in Texas's deregulated wholesale bulk power and retail electric market. ERCOT is regulated by the Public Utility Commission of Texas. ERCOT is generally not subject to FERC jurisdiction because it does not integrated with other electric systems, *i.e.*, there is not interstate electric transmission. ERCOT is the only market in which regulatory oversight of the wholesale and retail markets is performed by the same governmental entity.

In ERCOT, for each year, ERCOT determines a set of transmission constraints within its system which it deems Commercially Significant Constraints (CSCs). These constraints create Congestion Zones for which zonal ''shift factors'' are determined. Once approved by the ERCOT Board, the CSCs and Congestion Zones are used by the ERCOT dispatch process for the next year. In 2005, ERCOT has six CSCs and five Congestion Zones. When the CSCs bind, ERCOT economically dispatches generation units bid against load within each zone. To keep the system in balance in real time, ERCOT issues unit-specific instructions to manage Local (intrazonal) Congestion, then clears the zonal Balancing Energy Market. The balancing energy bids from all the generators are cleared in order of lowest to highest bid.[137]

At least one study argues that when there is local congestion, local market power is mitigated in ERCOT by ad hoc procedures that are aimed at keeping prices relatively low while maintaining transmission flows within limits. As a result, prices may be too low when there is local scarcity. In particular, prices may not be high enough to attract efficient new investment to provide long-term solutions to local market power problems. It is difficult for new entrants to contest such local markets, so that the local monopoly positions are essentially entrenched.[138]

New Generation Investment: In the late 1990s, developers added more than 16,000 megawatts of new capacity to the Texas market.[139] Certain aspects of the Texas market may make it attractive to new investment. Texas consumers directly pay (via their electricity bills) for updates to the transmission system required by the addition of new plants. In other states, FERC often requires developers to pay for system upgrades upfront and recoup the cost over time through credits against their transmission rates.[140]

6. The Northwest

Wholesale Market Organization: Wholesale customers obtain transmission service through agreements executed pursuant to individual utility OATTs. There are no centralized exchange markets specific to the region, but there is an active bilateral market for short-term sales within the Northwest and to the Southwest and California. Several trading hubs with significant levels of liquidity also are sources of price information. Multiple attempts to establish a centralized Northwest transmission operator have proven unsuccessful for a variety of reasons, including difficulties in applying standard restructuring ideas to a system dominated by cascading (i.e., interdependent nodes) hydroelectric generation and difficulties in understanding the potential cost shifts that might result in restructuring contract-based transmission rights.

New Generation Investment: The Northwest's generation portfolio is dominated by hydroelectric generation, which comprises roughly half of all generation resources in the region on an energy basis.[141] The remaining generation derives primarily from coal and natural gas resources, (with smaller contributions from wind, nuclear and other resources). The hydroelectric share of generation has decreased steadily since the 1960s.

The Northwest's hydroelectric base allows the region to meet almost any capacity demands required of the region—but the region is susceptible to energy limitations (given the finite amount of water available to flow through dams). This ability to meet peak demand buffers incentives for building new generation, which might be needed to assure sufficient energy supplies during times of drought because in three years out of four, hydro generation can displace much of the existing thermal generation in the Northwest. There has, however, been generation addition in the past years to meet load growth and to attempt to capitalize on high-prices during the Western energy crisis of 2001–02. Due to high power purchase costs during this crisis, some utilities have added thermal resources as insurance against drought-induced energy shortages and high prices. Altogether, over 3800 MWs of new generation has been added to the Northwest Power Pool since 1995—75% of that was commissioned in 2001 or later.

D. Factors That Affect Investment Decisions in Wholesale Electric Power Markets

The Task Force examined comments on how competition policy choices have affected the investment decisions of both buyers and sellers in wholesale markets. A number of issues emerged including the difficulty of raising capital to build facilities that have revenue streams that are affected by changing fuel prices, demand fluctuations and regulatory intervention and a perceived lack of long term contracting options. Some comments to the Task Force assert that significant problems still exist in these markets, particularly steep price increases in some locations without the moderating effect of long-term contracting and new construction.[142] In some markets, the problem is that prices are so low as to discourage entry by new suppliers, despite growing need.[143] Experience over the last 10 years shows three different regional competition models emerging. Each has its own set of benefits and drawbacks.

1. Long-Term Purchase Contracts—Wholesale Buyer Issues

Many wholesale buyers suggested that they had sought to enter into long-term contracts but found few or no offers.[144] The Task Force attempted to determine whether the facts supported these allegations by examining 2004–05 data collected by FERC through its Electric Quarterly Reports for three regions—New York, the Midwest, and the Southeast. Appendix E contains this analysis. Although not conclusive because of data limitations described in Appendix E, the analysis showed that contracts of less than one-year dominated each of the three regional markets examined and that in two of the

[137] *ERCOT Response to the DOE Question Regarding the Energy Policy Act 2005, available at http://www.oe.energy.gov/document/ercot2.pdf.*

[138] Ross Baldick and Hui Niu, *Lessons Learned: The Texas Experience, available at http://www.ece.utexas.edu/baldick/papers/lessons.pdf.*

[139] U.S. Gen. Accounting Office, GAO–02–427, *Restructured Electricity Markets, Three States' Experiences in Adding Generating Capacity* 9 (2002).

[140] *Id.* at 19.

[141] For a complete discussion of generation characteristics of the Northwest, *see* Nw. Power & Conn. Council, The Fifth Northwest Power and Conservation Plan, Ch. 2 (2005), *available at http://www.nwcouncil.org/energy/powerplan/plan/Default.htm.*

[142] ELCON; NRECA; APPA.

[143] *E.g.,* PJM; EPSA.

[144] ELCON.

markets, longer contract terms are associated with lower contract prices on a per MWh basis.

Three reasons may exist to explain the perceived lack of ability to enter long-term purchase power contracts.[145] First, some comments argued that organized exchange markets based on uniform price auctions (*e.g.*, PJM and NYISO) have made it difficult to arrange contracts with base-load and mid-merit generators at prices near their production costs.[146] These generators would rather sell in the exchange markets and obtain the market-clearing price, which may be higher than their production costs at various times. Base-load and mid-merit generators may see relatively high profits when gas-fueled generators are the marginal units, particularly when natural gas prices rise. Box 3–2 describes how prices are set in organized exchange markets. Natural gas-fueled generators in a uniform price auction may see lower profits as their fuel costs rise, to the extent other generation becomes relatively more economical.[147] Stated another way, when natural gas units set the market price, these units may recover only a small margin over their operating costs, while nuclear and coal units recover larger margins. Under traditional regulation, by contrast, all of an owner's generation units generally are allowed the same return, which may be less than marginal units, and more than infra-marginal units, in competitive markets.

In addition, the very competitiveness of these markets cannot be assumed. For example, over ten years ago, FERC requested comments on a wholesale ''PoolCo'' proposal, which was the predecessor entity to today's organized electricity market with open transmission access.[148] At the time, the Department of Justice generally supported the emerging market form but warned: ''The existence of a PoolCo cannot guarantee competitive pricing, since there may be only a small number of significant sellers into or buyers from the pool. The Commission should not approve a PoolCo unless it finds that the level of competition in the relevant geographic markets would be sufficient to reasonably assure that the benefits of eliminating traditional rate regulation exceed the costs.'' [149]

The fact that the market-clearing price in organized exchange markets may be established by a subset of generators depending upon demand and transmission congestion heightens the competitiveness concern in the organized markets. At one end, generators with high costs do not have much impact on the market prices when there is low demand and low transmission congestion, and conversely, generators with low costs do not have much impact on the market-clearing prices when there is high demand and high transmission congestion. There is a wide-range of market-clearing prices between these two end points based on the diversity of generator costs available in each region.[150] Indeed, some commenters specifically cited to recent studies of the electric industry that argue that a larger number of suppliers are needed to sustain competitive pricing in electricity markets than are needed for effective competition in other commodities.[151]

Second, the perceived lack of long-term purchase contracts may be due to a lack of trading opportunities to hedge these long-term commitments. Long-term contracts in other commodities are often priced with reference to a ''forward price curve.'' A forward price curve graphs the price of contracts with different maturities. The forward prices graphed are instruments that can be used to hedge (or limit) the risk that market prices at the time of delivery may differ from the price in a long-term contract. In a market with liquid forward or futures contracts, parties to a long-term contract can buy or sell products of various types and durations to limit their risk due to such price differences. Currently, liquid electricity forward or futures markets often do not extend beyond two to three years.[152] In some markets, one-year contracts are the longest products generally available; in markets where retail load is being served by contracts of fixed durations, such as the three-year obligations in New Jersey and Maryland, contracts for the duration of that period are slowly growing in number. But the relative lack of liquidity may discourage parties from signing long-term contracts, because they lack the ability to ''hedge'' these longer-term obligations.

Third, the availability of long-term purchase contracts depends on the availability and certainty of long-term delivery options. Particularly in organized markets, transmission customers have argued that the inability to secure firm transmission rights for multiple years at a known price introduces an unacceptable degree of uncertainty into resource planning, investment and contracting.[153] They report that this financial uncertainty has hurt their ability to obtain financing for new generation projects, especially new base-load generation.

Congress addressed this issue of insufficient long-term contracting in the context of RTOs and ISOs in EPACT05. In particular, section 1233 of EPACT05 provides that:

> [FERC] shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, *and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.*[154]

To implement this provision in RTOs and ISOs, FERC proposed new rules regarding FTRs in February 2006. The rules would require RTOs and ISOs to offer long-term firm transmission rights. FERC did not specify a particular type of long-term firm transmission right, but instead proposed to establish guidelines for the design and administration of these rights. The proposed guidelines cover basic design and availability issues, including the length of terms the rights should have and the allocation of those rights to transmission customers. FERC has received comments on its proposal but has not yet adopted final rules.

2. Long-Term Supply Contracts—Generation Investment Issues

Commenters cited the certainty of long-term contracts as a critical requirement for obtaining financing for new generators.[155] These contracts, however, are vulnerable to certain regulatory risks. First, contracts are

[145] In competitive markets, customers also have the ability to build their own generation facility if they are unable to obtain the long-term purchase contracts that they seek.

[146] APPA, NRECA.

[147] *See, e.g.*, Public Advocate's Office of Maine, National Association of State Utility Consumer Advocates.

[148] Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94–20–000.

[149] Comments of the U.S. Department of Justice, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94–20–00 filed March 2, 1995 at p. 6. *See also* Reply Comments of the U.S. Department of Justice, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94–20–00 filed April 3, 1995.

[150] *See* Comment of the Federal Trade Commission. Docket No. RM–04–7–000 (Jul. 16, 2004) at 7–8, *available at http://www.ftc.gov/os/comments/ferc/v040021.pdf.*

[151] APPA, Carnegie Mellon.

[152] Nodir Adilov, *Forward Markets, Market Power, and Capacity Investment* (Cornell Univ. Dep't of Econ. Job Mkt. Papers, 2005), *available at http://www.arts.cornell.edu/econ/na47/JMP.pdf.*

[153] APPA, TAPS.

[154] Pub. L. 109–58, § 1233, 119 Stat. 594, 958 (2005) (emphasis added).

[155] Constellation, Mirant.

subject to regulation by FERC, and a party to a contract can ask FERC to change contract prices and terms, even if the specific contract has been approved previously.[156] For example, in 2001–2002 several wholesale purchasers of electric power requested that FERC modify certain contracts entered into during the California energy crisis. The customers alleged that problems in the California electricity exchange markets had caused their contracts to be unreasonable. The sellers argued that if FERC overrides valid contracts, market participants will not be able to rely on contracts when transacting for power and managing price risk. FERC declined to change the contracts.[157] FERC cited its obligation to respect contracts except when other action is necessary to protect the public interest.[158]

A second type of regulatory uncertainty involving bankruptcy may limit future market opportunities for merchant generators and, thus, reduce their ability to raise capital. In recent years, several merchant generators (NRG, Mirant and Calpine) have sought to use the bankruptcy process to break long-term power contracts.[159] These efforts, when successful, leave counterparties facing circumstances that they did not anticipate when they entered into their contracts. This risk may give state regulators an incentive to favor construction of generation by their regulated utilities over wholesale purchases from merchant generators. These disputes have spawned conflicting rulings in the courts. In particular, these cases have centered on separate, but intertwined, issues: first, where jurisdiction over efforts to end power contracts properly lies, as between FERC and the bankruptcy courts and to what extent courts may enjoin FERC from acting to enforce power contracts; and second, what standard applies to such efforts (that is, what showing must a party make to rid itself of a contract). As FERC and the courts have only recently begun to consider these questions, the law remains unsettled, as do parties' expectations.[160]

A third type of regulatory uncertainty concerns the regulated retail service offerings in states with retail competition.[161] The uncertainty of how much supply a distribution utility will need to satisfy its customers due to customer switching that can occur in retail markets can prevent or discourage those utilities from signing long-term contracts.[162] The extent of this disincentive is unclear if competitive options are available for distribution utilities to purchase needed supply or sell excess supply.

3. Risk and Reward in the Face of Price and Cost Volatility—Capital Requirements

Building new generation in wholesale markets also is based on the ability of a company to acquire capital, either from internal sources or external capital markets. If a company can acquire the necessary capital it can build. There is no Federal regulation of entry, and most states that have permitted retail competition have eliminated any ''need-based'' showing to build a generation plant.

Private capital has generally funded the electric power transmission network in the United States. Under traditional cost-base rate regulation, utility investment decisions were based in part on the promise of a regulated revenue stream with little associated risk to the utility. The ratepayers often bore the risk. Money from the capital markets was generally available when utilities needed to fund new infrastructure. One significant problem, however, was that regulators had limited ability to ensure that utilities spent their money wisely.[163] Regulatory disallowances of imprudent expenditures are viewed by investors as regulatory risk. This risk can be mitigated somewhat by Integrated Resource Planning, to the extent it limits or avoids after-the-fact regulatory reviews of investment decisions.[164]

In competitive markets, projects obtain funding based on anticipated market-based projections of costs, revenues and relevant risks factors. The ability to obtain funding is impacted by the degree to which these projections compare with projected risks and returns for other investment opportunities.[165] Therefore, potential entrants to generation markets have to be able to convince the capital markets that new generation is a viable profitable undertaking. In the late 1990s investors appeared to prefer market investments over cost-based rate-regulated investments, as merchant generators were able to finance numerous generation projects, even without a contractual commitment from a customer to buy the power.[166]

In recent years, however, investors have generally favored traditional utilities over merchant generators when it comes to providing capital for large investments.[167] In part, this preference reflects the reduced profitability of many merchant generators in recent years, and the relative financial strength of many traditional utilities. It also may reflect a disproportionate impact of the collapse of credit and thus trading capability of non-utilities after Enron's financial collapse.[168] As shown in the Table in Appendix G, for example, virtually all of the companies rated A- or higher are traditional utilities, not merchant generators.

Investor preference for traditional utilities also may be affected by increasing volatility in electric power markets. As wholesale markets have opened to competition, investors recognized that income streams from the newly-built plants would not be as predictable as they had been in the past.[169] Under cost-based regulation, vertically integrated utilities' monopoly franchise service territories significantly limited the risk that they would not recover the costs of investments. Once generators had to compete for sales, generation plant investors were no longer guaranteed that construction costs would be repaid or that the output

[156] In December 2005, FERC proposed to adopt a general rule on the standard of review that must be met to justify proposed modifications to contracts under the Federal Power Act and the Natural Gas Act. *Standard of Review for Modifications to Filed Agreements*, 113 FERC ¶ 61,317 (2005) (Proposed Rule). Specifically, FERC proposed that, in the absence of specified contractual language, a party seeking to change a contract must show that the change is necessary to protect the public interest. FERC explained that its proposal recognized the importance of providing certainty and stability in energy markets, and helped promote the sanctity of contracts. A final rule is pending.

[157] *Nevada Power Company* v. *Enron*, 103 FERC ¶ 61,353, *order on reh'g*, 105 FERC ¶ 61,185 (2003); *Public Utilities Commission of California* v. *Sellers of Long Term Contracts*, 103 FERC ¶ 61,354, *order on reh'g*, 105 FERC ¶ 61,182 (2003); *PacifiCorp* v. *Reliant Energy Services, Inc.*, 103 FERC ¶ 61,355, *order on reh'g*, 105 FERC ¶ 61,184 (2003).

[158] *See Northeast Utilities Service Co.*, v. *FERC*, 55 F.3d 686, 689 (1st Cir. 1995).

[159] *See* Howard L. Siegel, *The Bankruptcy Court* vs. *Ferc—The Jurisdictional Battle*, 144 Pub. Util. Fortnightly 34 (2006).

[160] At least one rating agency treats a utility's self-built generation as an asset while treating long-term purchase contracts as imputed debt, thus making it less attractive for utilities to choose the contract option.

[161] *See infra* Chapter 4 for a discussion of regulated service offerings in states with retail competition.

[162] Mirant, Constellation.

[163] Cong. Budget Office, Financial Condition of the U.S. Electric Utility Industry (1986), *available at http://www.cbo.gov/showdoc.cfm?index=5964&sequence=0.*

[164] Southern, Duke.

[165] Commodity Futures Trading Comm'n, The Economic Purpose of Futures Markets, *available at http://www.cftc.gov/opa/brochures/opaeconpurp.htm.*

[166] APPA.

[167] Task Force Meetings with Credit Agencies, see Appendix B.

[168] U.S. Gen. Accounting Office, GAO–02–427, Restructured Electricity Markets, Three States' Experiences in Adding Generating Capacity 13 (2002).

[169] Connecticut DPUC.

from plants could be sold at a profit.[170] Financing was more readily accessed for projects like combined cycle gas and particularly gas turbines that can be built relatively quickly and were viewed at the time to have a cost advantage compared with existing generation already in operation, including less efficient gas-fueled generators.[171] In 1996, the Energy Information Administration projected that 80% of electric generators between 1995 and 2015 would be combined cycle or combustion turbines.[172] Base-load units, such as coal plants, with construction and payout periods that would put capital at risk for a much longer period of time, were harder to finance.[173]

Box 3–3: The Use of Capacity Credits in Organized Wholesale Markets

In theory, capacity credits could support new investment because suppliers and their investors would be assured a certain level of return even on a marginal plant that ran only in times of high demand. Capacity credits might allow merchant plants to be sufficiently profitable to survive even in competition with the generation of formerly-integrated local utilities that may have already recovered their fixed costs.

The increasing amount of new generation fueled by natural gas, however, has caused electricity prices to vary more frequently with natural gas prices, a commodity subject to wide swings in price.[174] With input costs varying widely, but merchant revenues often limited by contract or by regulatory price mitigation, investors may worry that merchant generators may not recover their costs and provide an attractive rate of return.

4. Regulatory Intervention May Affect Investment Returns

Generation investors must expect to recover not only their variable costs but also an adequate return on their investment to maintain long-term financial viability. One way for suppliers to recover their investment is to charge high prices during periods of high demand. However, regulators may limit recovery of high prices during these periods, and thus may deter suppliers from making needed investments in new capacity that would be economical absent these price caps.

This dynamic leads to a chicken-and-egg conundrum: If there were efficient investment, there might not be a need for wholesale price or bid caps. More investment in capacity would lead to less scarcity, and thus fewer or shorter episodes of high prices that may require mitigation. By contrast, it may be that price regulation during high-priced hours diminishes the confidence of investors that they can rely on market forces (rather than regulation) to set prices. That diminished confidence in their ability to earn sufficient investment returns thus deters entry of new generation supply.

Price mitigation through the use of price or bid caps has become an integral component of most organized markets. The use of mitigation has led generators to seek a supplemental revenue stream (capacity credits) to encourage entry of new supply. *See* Box 3–3 for a discussion of capacity credits.

In practice, however, the presence or absence of capacity credits has not always resulted in the predicted outcomes. California did not have capacity credits and did not experience much new generation, but two of the regions (the Southeast and Midwest) experienced significant new generation entry without capacity credits. Northeast RTOs with capacity credits continue to have some difficulty attracting entry, especially in major metropolitan areas.

As noted above, much of the new generation in the Southeast was non-utility merchant generation, and relied on the region's proximity to natural gas supplies. In the Midwest, in the late 1990s, largely uncapped prices were allowed to send price signals for investment. In California, price caps of various kinds have been used for a number of years, limiting price signals for new entry. In the Northeast, organized markets have offered capacity payments for long term investments in addition to electric power prices that are sometimes capped in the short term. Unfortunately, there is no conclusive result from any of these approaches—no one model appears to be the perfect solution to the problem of how to spur efficient investment with acceptable levels of price volatility.

Net revenue analyses for the centralized markets with price mitigation suggest that price levels are inadequate for new generation projects to recover their full costs. For example, in the last several years, net revenues in the PJM markets have been, for the most part, too low to cover the full costs of new generation in the region.[175] Based on 2004 data, net revenues in New England, PJM and California would have allowed a new combined-cycle plant to recover no more than 70% of its fixed costs.

Regulation also may interfere with efficient exit of generation plants due to the use of reliability-must-run requirements. In some load pockets in organized markets, plant owners are paid above-market prices to run plants that are no longer economical at the market-clearing price. For example, in its Reliability Pricing Model filing with FERC, PJM states, ''PJM also has been forced to invoke its recently approved generation retirement rules to retain in service units needed for reliability that had announced their retirement. As the Commission often has held, this is a temporary and sub-optimal solution. Such compensation, like the reliability must run (''RMR'') contracts allowed elsewhere, is outside the market, and permits no competition from, and sends no price signals to, other prospective solutions (such as new generation or demand resources) that might be more cost-effective.'' [176] To the extent that market rules allocate the cost of keeping these plants running to customers outside of the load pocket, such payments may distort price signals that, in the long run, could elicit entry. Graduated capacity payments that favor new entry of efficient plants may be a partial solution to retirement of inefficient old plants.

5. Investment in Transmission: A Necessary Adjunct to Generation Entry

Transmission access can be vital to the competitive options available to market participants. For example, merchant generators depend on the availability of transmission to sell power, and transmission constraints can limit their range of potential customers. Small utilities, such as many municipal and cooperative utilities, depend on the

[170] U.S. Gen. Accounting Office, GAO–02–427, Restructurd Electricity Markets, Three States' Experiences in Adding Generating Capacity 13 (2002).

[171] Energy Info. Admin., DOE/EIA–0562(96), The Changing Structure of the Electric Power Industry: An Update 38 (1996).

[172] *Id.*

[173] Hearing on Nuclear Power, Before the Subcomm. on Energy of the S. Comm. on Energy & Nat'l Res., Mar. 4, 2004 (statement of Mr. James Asselstine, Managing Director, Lehman Brothers); *see also* Nuclear Energy Institute, Investment Stimulus for New Nuclear Power Plant Construction: Frequently Asked Questions, *available at http://www.nei.org/documents/New_Plant_Investment_Stimulus.pdf.*

[174] Natural Gas, Factors Affecting Prices and Potential Impacts on Consumers, Testimony Before the Permanent Subcommittee on Investigations, Committee on Homeland Security and Governmental Affairs, United States Senate; GA)–06–420T (February 13, 2006) at 7.

[175] Occasionally in the past few years net revenues have been sufficient to cover the costs of new peaking units, and in 2005 they were enough to cover the costs of a new coal plant. Market Monitoring Unit, PJM Interconnection, LLC, 2005 State of the Market Report, at 118 (2006) [hereinafter PJM State of the Market Report 2005], *available at http://www.pjm.com/markets/market-monitor/som.html.*

[176] Intial Order on Reliability Pricing Model, 115 FERC ¶ 61,079, *3 (2006)

availability of transmission to buy wholesale power, and transmission constraints can limit their range of potential suppliers. Much of the transmission grid is owned by vertically-integrated, investor-owned utilities and, traditionally, these utilities have an incentive to limit the use by others of the grid, to the extent such use conflicts with sales by their own generation. In short, the availability of transmission is often the keystone in determining whether a generating facility is likely to be profitable and, thus, to elicit investment in the first instance.

Since FERC issued Order No. 888 in 1996, questions have arisen concerning the efficacy of various terms and conditions governing the availability of transmission. For example, transmission customers have raised concerns regarding the calculation of Available Transfer Capacity (ATC). Another area of concern is the lack of coordinated transmission planning between transmission providers and their customers. Finally, customers have raised concerns about aspects of transmission pricing. Based on these concerns, FERC in May 2006 proposed modifications to public utility tariffs to prevent undue discrimination in the provision of transmission services. FERC is soliciting public comments on its proposed modifications.

As discussed above, generation that is built where fuel supplies are readily available, but not necessarily near demand, and construction costs are low, rely heavily on readily available transmission. The Connecticut DPUC noted that while generation growth may have been sufficient for some regions such as New England as a whole, some localized areas had demand growth without increases in supply, raising prices in load pockets. If transmission access to the load pocket were available, a large base-load plant outside the load pocket might become an attractive investment proposition.

Less regulatory intervention in wholesale markets for generation may be necessary if transmission upgrades, rather than unrestricted high prices or capacity credits, are used to address the concerns about future generation adequacy. Although capacity credits may spur generators within a load pocket to add additional capacity, capacity credits may not be required for base-load plants outside the load pocket. Those base-load plants would not have the problem of average revenues falling below average costs because they would have access to more load, and be able to run profitably during more hours of the day. Similarly, price caps may be unnecessary if improved transmission brought power from more base-load units into the congested areas. Prices would be lower because there would be less scarcity, and high cost units would be needed to run during fewer hours.

E. Observations on Wholesale Market Competition

One of the most contentious issues currently facing federal regulators is whether the different forms of competition in wholesale markets have resulted in an efficient allocation of resources. The various approaches used by the different regions show the range of available options.

1. Open Access Transmission without an Organized Exchange Market

One option is to rely upon the OATT to make generation options available to wholesale customers. No central exchange market for electric power operates in regions taking this option (the Northwest and Southeast) Instead, wholesale customers shop for alternatives through bilateral contracts with suppliers and separately arrange for transmission via the OATT. With a range of supply options to choose from, long-term bilateral contracts for physical supply can provide price stability that wholesale customers seek and a rough price signal to determine whether to build new generation or buy generation in wholesale markets. However, prices and terms can be unique to each transaction and may not be publicly available. Furthermore, the lack of centralized information about trades leaves transmission operators with system security risks that necessitate constrained transmission capacity. The lack of price transparency can also add to the difficulty of pricing long-term contracts in these markets.

This model is extremely dependent on the availability of transmission capacity that is sufficient to allow buyers and sellers to connect. Thus, it also is dependent upon the accurate calculation and reporting of transmission capacity available to market participants. Short-term availability is not sufficient, even if accurately reported, to form a basis for long term decisions such as contracting for supply or building new generation. Not only must transmission be available, but it must be seen to be available on a nondiscriminatory basis. As the FERC noted in Order 2000, persistent allegations of discrimination can discourage investment even if they are not proven. Without the assurance of long term transmission rights, wholesale customers may remain dependent on local generation owned by one or only a few sellers and be denied the competitive options supplied by more distant generation. Similarly, new suppliers may have no means of competing with incumbent generators located close to traditional load.

2. Policy Options in Organized Wholesale Markets

In organized markets, market participants have access to an exchange market where prices for electric power are set in reference to supply offers by generators and demand by wholesale customers (including Load Serving Entities or LSEs). Such an exchange market could have prices set by a number of mechanisms. All existing U.S. exchange markets have a uniform price auction to determine the price of electric power. Uniform price auctions theoretically provide suppliers an incentive to bid their marginal costs, to maximize their chance of getting dispatched. The principal alternative to uniform price auctions is a pay-as-bid market.

The academic research on whether pay-as-bid auctions can actually result in lower prices has been evolving, and the results are at best mixed. Theoretically, pay-as-bid auctions do not result in lower market-clearing prices and may even raise prices, as suppliers base their bids on forecasts of market-clearing prices instead of their marginal costs. More recent research suggests that pay-as-bid can sometimes result in lower costs for customers.[177] But, the pay-as-bid approach may reduce dispatch efficiency, to the extent generator bids deviate from their marginal costs.[178]

A uniform price auction may allow some generators (*e.g.*, coal- or nuclear-fueled units) to earn a return above those typically allowed under cost-based regulation, but it also may limit the return of other generators (*e.g.*, natural gas-fueled units) to a return below those typically allowed under cost-based regulation. In a competitive market, a unit's profitability in a uniform price auction will depend on whether, and by how much, its production costs are below the market clearing price. A uniform price auction

[177] Par Holmberg, *Comparing Supply Function Equilibria of Pay-as-Bid and Uniform Price Auctions* (Uppsala University, Sweden Working Paper 2005:17, 2005); G. Federico & D. Rahman, *Bidding in an Electricity Pay-As-Bid Auction* (Nuffield College Discussion Paper No 2001–W5, 2001); Joskow, Difficult Transition at 6–7.

[178] Alfred E. Kahn, *et al.*, *Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond* (Blue Ribbon Panel Report, study commissioned by the California Power Exchange, 2001).

may thus produce prices that are very high compared with the costs of some generators and yet not high enough to give investors an incentive to build new generation that could moderate prices going forward. The uniform price auction creates strong incentives for entry by low-cost generators that will be able to displace high cost generators in the merit dispatch order. Three policy options have been suggested to address the tension between market-clearing prices with uniform auction and entry.

a. Unmitigated Exchange Market Pricing

One possible, but controversial, way to spur entry is to let wholesale market prices rise. As discussed in Chapter 2, the market will likely respond in two ways. First, the resulting price spikes will attract capital and investment. To assure that the price signals elicit appropriate investment and consumption decisions, they must reflect the differences in prices of electricity available to serve particular locations. Where transmission capacity limits the availability of electric power from some generators within a regional market, the cost of supplying customers within the region may vary. Without locational prices, investors may not make wise choices about where to invest in new generation.

Unfortunately, it is difficult to distinguish high prices due to the exercise of market power from those due to genuine scarcity. High prices due to scarcity are consistent with the existence of a competitive market, and therefore perhaps suggest less need for regulatory intervention. High prices stemming from the exercise of market power in the form of withholding capacity may justify regulatory intervention. Being able to distinguish between the two situations is therefore important in markets with market-based pricing.[179]

Second, higher prices will likely signal to customers that they should change their decisions about how much and when to consume. Price increases signal to customers to reduce the amount they consume. Indeed, during the Midwest wholesale price spikes in the summer of 1998, demand fell during the period in which prices rose and customers purchased little supply during those periods.[180] For an efficient reduction in consumption to occur, however, retail customers must have the ability to react to accurate price signals. As discussed in Chapter 4, customers often have limited incentive, even in markets with retail competition, to reduce their consumption when the marginal cost of electricity is high. This is because retail rates in the short-term do not vary to account for the costs of providing the electricity at the actual time it was consumed.

b. Moderation of Price Volatility With Caps and Capacity Payments

To date, the alternative to unmitigated exchange market pricing has been price and bid caps in wholesale exchange markets. Although price and bid caps may moderate wide swings in market-clearing prices, not all the caps in place may be necessary to prevent exercise of market power or set at appropriate levels. Higher caps may strike a balance between the desire of policy makers to smooth out the peaks of the highest price spikes and the need to demonstrate where capital is required and can recover its full investment. Some argue, however, that high price caps may burden consumers with high prices and yet not allow prices to rise to the level that will actually insure that investors will recover the cost of new investment. Thus prices can rise significantly and yet not elicit entry by additional supply that could moderate price in later periods.

Capacity payments are one way to ensure that investors recover their fixed costs. Capacity payments can provide a regular payment stream that, when added to electric power market income, can make a project more economically viable than it might be otherwise. Like any regulatory construct, however, capacity payments have limitations. It is difficult to determine the appropriate level of capacity payments to spur entry without over-taxing market participants and consumers.

To the extent that capacity rules change, this creates a perception of risk about capacity payments that may limit their effectiveness in promoting investment and ultimately new generation. When rules change, builders and investors may also take advantage of short-term capacity payment spikes in a manner that is inefficient from a longer-term perspective.

If capacity payments are provided for generation, they may prompt generation entry when transmission or demand response would be more affordable and equally effective. Capacity payments also may disproportionately reward traditional utilities and their affiliates by providing significant revenues for units that are fully depreciated. Capacity payments also may discourage entry by paying uneconomical units to keep running instead of exiting the market. These concerns can be addressed somewhat by appropriate rules—*e.g.*, NYISO's rules giving capacity payment preference to newly-entered units—but in general, it is difficult to tell whether capacity payments alone would spur economically efficient entry.

One issue that has arisen is whether capacity prices should be locational, similar to locational electric power prices. PJM, ISO–NE and NYISO have either proposed or implemented locational capacity markets that may increase incentives for building in transmission-constrained, high-demand areas. The combination of high electric power prices and high capacity prices in these areas may combine to create an adequate incentive to build generation in load pockets.[181]

c. Encouraging Additional Transmission Investment

Building the right transmission facilities may encourage entry of new generation or more efficient use of existing generation. But transmission expansion to serve increased or new load raises the difficulty of tying the economic and reliability benefits of transmission to particular consumers. In other words, because transmission investments can benefit multiple market participants, it is difficult to assess who should pay for the upgrade. This challenge may cause uncertainty about the price for transmission and about return on investment both for new generators and for transmission providers.

If transmission entry can connect low-cost resources to high-demand areas, it is closely linked to the issues of generation entry. Transmission entry, however, can in theory remove the kinds of transmission congestion that results in higher prices in load pockets. Transmission entry may be a double-edged sword: if it is expected to occur, it would reduce the incentive of companies to consider generation entry, by eliminating the high prices they hope to capture.

Both generation and transmission builders face the issue of dealing with an existing transmission owner or an RTO/ISO to obtain permission to build. Moreover, there are substantial difficulties to site new transmission lines. It is difficult to assess whether

[179] *See generally Edison Mission Energy, Inc.* v. *FERC*, 394 F.3d 964 (DC Cir. 2005).

[180] Robert J. Michaels and Jerry Ellig, *Price Spike Redux: A Market Emerged, Remarkably Rational*, 137 Pub. Util. Fortnightly 40 (1999). Wholesale customers with supply contracts for which the prices were tied to the market price paid higher prices for electric power during those hours.

[181] Siting in these areas can be difficult or impossible as a result of land prices, environmental restrictions, aesthetic considerations, and other factors.

these risks are higher for transmission builders than for generation builders.

d. Governmental Control of Generation Planning and Entry

The final alternative is a regulatory rather than a market mechanism to assure that adequate generation is available to wholesale customers. As a method to spur investment, regulatory oversight of planning has some positive aspects, but it also has costs. Using regulation through governmentally determined resource planning to encourage entry could result in more entry than market-based solutions, but that entry may not occur where, when or in a way that most benefits customers. Regulatory oversight of investment also means regulators can bar entry for reasons other than efficiency. The stable rate of return on invested capital offered under rate-regulation can encourage investment. On the other hand, rate-regulation can lead to overinvestment, excessive spending and unnecessarily high costs. Regulation also lacks the accountability that competition provides. Mistakes as to where and how investments should be made may be borne by ratepayers. In competitive markets, the penalties for such mistakes would fall on management and shareholders. The specter of future accountability for investment decisions can lead to better decision-making at the outset.[182]

It is possible that regulatory oversight of planning would result in greater fuel diversity, and thus less exposure to risks associated with changes in fuel prices or availability. It could also lessen potential boom-bust cycles where investors overreact to market signals and too many parties invest in one region. That reaction creates overcapacity, which in turn leads to lower prices. One large drawback to regulation, however, is the regulator's lack of knowledge about the correct price to set. It is difficult to set the correct price unless frequent experimentation with price changes is possible, and yet consumers generally do not favor significant price variation.

Chapter 4—Competition in Retail Electric Power Markets

A. Introduction and Overview

Congress required the Task Force to conduct a study of competition in retail electricity markets. This chapter examines the development of competition in retail electricity markets and discusses the status of competition in the 16 states and District of Columbia that currently allow their customers to choose their electricity supplier.

Although it has been almost a decade since states started to implement retail competition, residential customers in most of these states still have very little choice among suppliers. Few residential customers have switched to alternative suppliers or marketers in these states. Commercial and industrial customers, however, have more choices and options than residential customers, but in several states these customers have become increasingly dissatisfied with increasing prices. Residential, commercial, and industrial customers in states with retail competition often have limited ability to adjust their consumption in response to price changes.

One of the main impediments to market-based competition has been the lack of entry by alternative suppliers and marketers to serve retail customers. Unlike markets in other industries, most states required the distribution utility to offer customers electricity at a regulated price as a backstop or default if the customer did not choose an alternative electricity supplier or the chosen supplier went out of business. States argued that a regulated service was necessary to ensure universal access to affordable and reliable electricity.

States often set the price for the regulated service at a discount below then-existing rates and capped the price for multi-year periods. These initial discounts sought to approximate the anticipated benefits of competition for residential customers. Since then, wholesale prices have increased. More than any other policy choice surrounding the introduction of retail competition, this policy of requiring distribution utilities to offer service at low prices unintentionally impeded entry by alternative suppliers to serve retail customers—new entrants cannot compete against a below-market regulated price.

States with below-market, regulated prices now face a chicken-or-egg problem and ''rate shock.'' With rate caps set to expire for the regulated service that most residential customers use, states are loath to subject their customers to substantially higher market prices that the distribution utilities indicate they must charge. These higher prices are even more painful to customers because they have few tools to adjust their consumption as wholesale prices vary over time. However, if states require the distribution utility to offer regulated service at below-market rates, retail entry, and thus competition, will not occur. Moreover, below-market rates put the solvency of the distribution utility at risk.

This conundrum is further complicated by the fact that most distribution utilities that offer the regulated service no longer own generation assets. The utilities in many states sold their generation assets or transferred them to unregulated affiliates at the beginning of retail competition. Thus, distribution utilities that offer the regulated service must purchase supply in wholesale markets. Attempts to reassemble the vertically integrated distribution company face the reality that prices for many generation assets may be higher now than when they were divested at the beginning of retail competition. If the utility re-purchases these assets at these higher prices, it is likely to have ''sold low and bought high.'' In both cases, the competitiveness of wholesale prices has a direct impact on the retail prices consumers pay.

This chapter addresses the status and impact of retail competition in seven states that the Task Force examined in detail: Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas. See Appendix D for each state profile. These seven states represent the various approaches that states have used to introduce retail competition.[183] The Chapter also discusses why it is difficult at this time to determine whether retail prices are higher or lower than they otherwise would be absent the move to retail competition.

The chapter provides several observations based on the experiences of states that have implemented retail

[182] Regulatory solutions, more so than market-based outcomes, may outlive the circumstances that made them seem reasonable.

[183] Restructured states as of May 2006 include: Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia, plus the District of Columbia. The seven profiled states include a range of conditions that are similar to the other states with retail competition. Virginia is similar to Pennsylvania in that their transitions to retail competition are over approximately a 10-year period. Maine and Rhode Island are similar to New York and Texas in that prices for POLR service have been regularly adjusted to reflect changes in wholesale prices. Delaware, the District of Columbia, Illinois, Michigan, New Hampshire, Ohio and Rhode Island share the situation in Maryland with the transition period of fixed prices for residential and small C&I POLR service coming to an end in the near future. Massachusetts' rate cap period ended recently. Many of the states about to end the transition period, share the development of approaches to bring POLR prices for residential and small C&I customers up to market rates in stages rather than all at once. Several of these states also share Maryland's and New Jersey's interest in auctions for procuring POLR service supplies. Oregon's situation differs from the other states in that only nonresidential customers can shop and the shopping is limited to a short window of time each year.

competition with an emphasis on how states can minimize market distortions once the rate caps expire. States with expiring rates caps face several choices on whether and how to rely on competition, rather than regulation, to set the retail price for electric power.

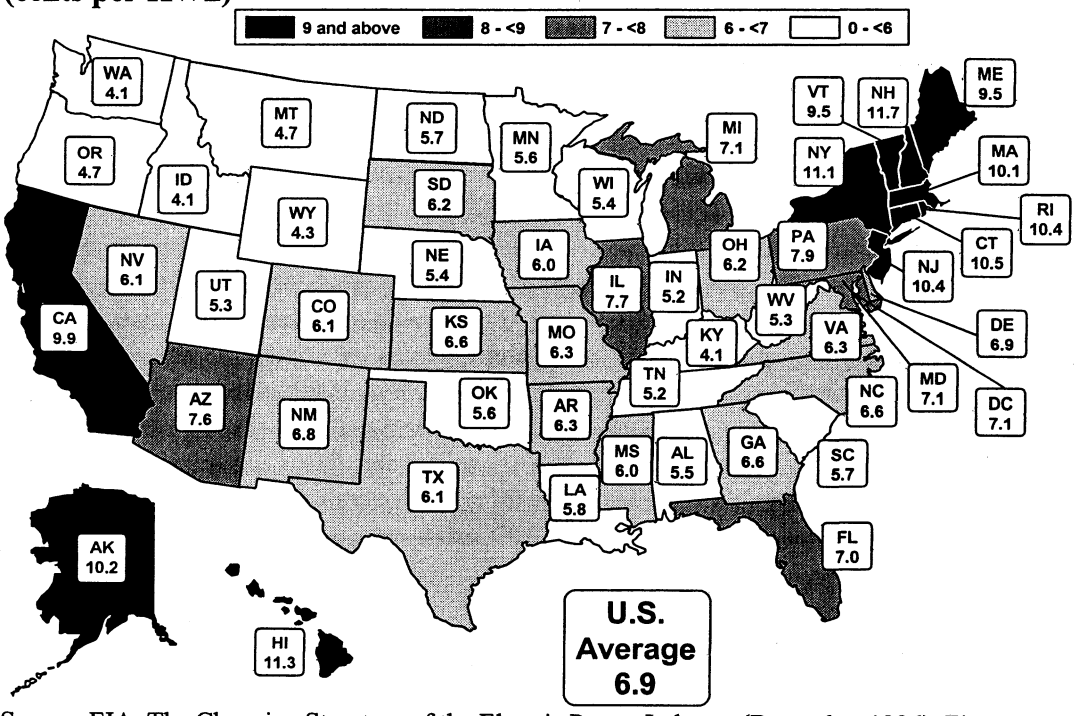
B. Background on Provision of Electric Service and the Emergence of Retail Competition

For most of the 20th century, local distribution utilities typically offered electric service at rates designed for different customer classes (*e.g.*, residential, commercial, and industrial). State regulatory bodies set these rates based on the utility's costs of generating, transmitting, and distributing the electricity to customers. Locally elected boards oversaw the rates for customers of public power and cooperative utilities. For investor-owned systems, the regulated rate included an opportunity to earn an authorized rate of return on investments in utility plant used to serve customers. Public power and cooperative systems operate under a cost of service non-profit structure and rates typically include a margin adequate to cover unanticipated costs and support new investment.

With minor variations, monopoly distribution utilities deliver electricity to retail customers.[184] Industrial customers sometimes had more options as to service offerings and rate structures (*e.g.*, time-of-use rates, etc.) than residential and small business customers.[185]

Beginning in the early 1990s, several states with high electricity prices began to explore opening retail electric service to competition. As discussed in Chapter 1 and Figure 4–1, rates varied substantially among utilities, even those in the same state. Some of the disparity was due to different natural resource endowments across regions—most important the hydroelectric opportunities in the Northwest and states such as Kentucky and Wyoming with abundant coal reserves. Also, some states required utilities to enter into PURPA contracts at prices much higher than the utilities' avoided costs. In addition to these rate disparities, some industrial customers contended that their rates subsidized lower rates for residential customers.

Figure 4-1: U.S. Electric Power Industry, Average Retail Price of Electricity by State, 1995 (cents per KWh)



Source: EIA, The Changing Structure of the Electric Power Industry (December 1996), Figure 11.

With retail competition, customers could choose their electric supplier or marketer, but the delivery of electricity would still be done by the local distribution utility.[186] The idea was that customers could obtain electric service at lower prices if they could choose among suppliers. For example, they could buy from suppliers located outside their local market, from new entrants into generation, or from marketers, any of which might have lower prices than the local distribution utility. Moreover, the ability to choose among alternative suppliers would reduce any market power that local suppliers might otherwise have, so that purchases could be made from the local suppliers at lower prices than would otherwise be the case. Also, customers might be able to buy electricity on innovative price or other terms offered by new suppliers.

[184] In 30 states retail electric customers continue to receive service almost exclusively under a traditional regulated monopoly utility service franchise. These states include 44% of all U.S. retail customers which represents 49% of electricity demand.

[185] For example, Georgia law allows any new customers with loads of 900 kilowatts or more to make a one time selection from among competing eligible electric suppliers. Southern.

[186] The FERC and the state will continue to regulate the price for transmission and distribution services and, in most states, the local distribution utility will continue to deliver the electricity, regardless of which generation supplier the customer chooses.

In 1996, California enacted a comprehensive electric restructuring plan to allow customers to choose their electricity supplier. To accommodate retail choice, California extensively restructured the electric power industry. The legislation:

(1) Established an independent system operator to operate the transmission grid throughout much of the state so that all suppliers could access the transmission grid to serve their retail customers;

(2) Established a separate wholesale trading market for electricity supply so that utilities and alternative suppliers could purchase supply to serve their retail customers;

(3) Mandated a 10 percent immediate rate reduction for residential and small commercial customers for those customers that did not choose an alternative supplier;

(4) Authorized utilities to collect stranded costs related to those generation investments that were unlikely to be as valuable in a competitive retail environment; and

(5) Implemented an extensive public benefits program funded by retail ratepayers.[187]

Other states also enacted comprehensive legislation. In May 1996, New Hampshire enacted retail competition legislation—Rhode Island (August 1996), Pennsylvania (December 1996), Montana (April 1997), Oklahoma (May 1997), and Maine (May 1997)—all followed suit. By January 2001, some 22 states and the District of Columbia had adopted retail competition legislation. Regulatory commissions in four other states (including Arizona which also enacted legislation) had issued orders requiring or endorsing retail choice for retail electric customers. (See chart and timeline with retail choice legislation dates) Several states, primarily those with low-cost electricity such as Alabama, North Carolina, and Colorado, concluded that the retail competition would not benefit their customers. In Colorado, for example, limitations on transmission access and a high concentration among generator suppliers led the state to be concerned that these suppliers would exercise market power to the detriment of customers. These states opted to keep traditional utility service.

States adopting retail competition plans generally did so to advance several goals. These goals included:

- Lower electricity prices than under traditional regulation through access to lower cost power in competitive wholesale markets where generators competed on price and performance;
- Better service and more options for customers through competition from new suppliers;
- Innovation in generating technologies, grid management, use of information technology, and new products and services for consumers;
- Improvements in the environment through displacement of dirtier, more expensive generating plants with cleaner, cheaper, natural gas and renewable generation.

At the same time, legislatures and regulators affirmed support for the availability of electricity to all customers at reasonable rates with continuation of safe and reliable service and consumer protections under regulatory oversight under the restructured model. Boxes 4–1 and 4–2 describe the Pennsylvania and New Jersey Legislatures' finding and expected results of retail competition.

Box 4–1: Findings of the Pennsylvania Legislature

The findings of the Pennsylvania General Assembly demonstrate these varied goals:

(1) Over the past 20 years, the federal government and state government have introduced competition in several industries that previously had been regulated as natural monopolies.

(2) Many state governments are implementing or studying policies that would create a competitive market for the generation of electricity.

(3) Because of advances in electric generation technology and federal initiatives to encourage greater competition in the wholesale electric market, it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market as long as safe and affordable transmission and distribution is available at levels of reliability that are currently enjoyed by the citizens and businesses of this Commonwealth.

(4) Rates for electricity in this commonwealth are on average higher than the national average, and significant differences exist among the rates of Pennsylvania electric utilities.

(5) Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity.

Source: Pennsylvania HB 1509 (1995), *available at http://www.legis.state.pa.us/WU01/LI/BI/BT/1995/0/HB1509P4282.HTMhttp://www.legis.state.pa.us/WU01/LI/BI/BT/1995/0/HB1509P4282.HTMhttp://www.legis.state.pa.us/WU01/LI/BI/BT/1995/0/HB1509P4282.HTM*

Box 4–2: Findings of the New Jersey Legislature

''The [New Jersey] Legislature finds and declares that it is the policy of this State to:

(1) Lower the current high cost of energy, and improve the quality and choices of service, for all of this State's residential, business and institutional consumers, and thereby improve the quality of life and place this State in an improved competitive position in regional, national and international markets;

(2) Place greater reliance on competitive markets, where such markets exist, to deliver energy services to consumers in greater variety and at lower cost than traditional, bundled public utility service; * * *

(3) Ensure universal access to affordable and reliable electric power and natural gas service;

(4) Maintain traditional regulatory authority over non-competitive energy delivery or other energy services, subject to alternative forms of traditional regulation authorized by the Legislature;

(5) Ensure that rates for non-competitive public utility services do not subsidize the provision of competitive services by public utilities; * * *

C. Meltdown and Retrenchment

Starting in the late spring 2000 and lasting into the spring of 2001, California experienced high natural gas prices, a strained transmission system, and generation shortages. Wholesale prices increased substantially during this time frame. State law capped residential provider of last resort (POLR) rates at levels that were soon below the market price paid by utilities for wholesale electric power. One of California's large investor owned utilities declared bankruptcy because it could not increase its retail rates to cover the high wholesale power prices. The state stepped in to acquire electricity supply on behalf of two of the three IOUs operating in California.[188] California eventually suspended retail competition for most customers while it reconsidered how to assure adequate electric supplies and continuation of service at affordable rates in a competitive wholesale market environment. The suspension continues today. Box 4–3 describes the State's role in purchasing electricity and the all-time high prices it paid, and continues to pay, for such electricity.

[187] Ca. AB 1890, *available at http://www.leginfo.ca.gov/pub/95–96/bill/asm/ab_1851–1900/ab_1890_bill_960924_chaptered.pdf.*

[188] *See, e.g.,* California Attorney General's Energy White Paper, A Law Enforcement Perspective on the California Energy Crisis, Recommendations for Improving Enforcement and Protecting Consumers in Deregulated Energy Markets (Apr. 2004), *available at http://ag.ca.gov/publications/energywhitepaper.pdf;* Federal Energy Regulatory Commission, *Final Report on Price Manipulation in Western Energy Markets: Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices,* Docket No. PA02–2–000 (March 26, 2003); U.S. General Accounting Office, *Restructured Electricity Markets, California Market Design Enabled Exercise of Market Power,* (June 2002), *available at http://www.gao.gov/new.items/d02828.pdf.*

Box 4–3: The State of California's Electricity Purchases at All-Time High Prices

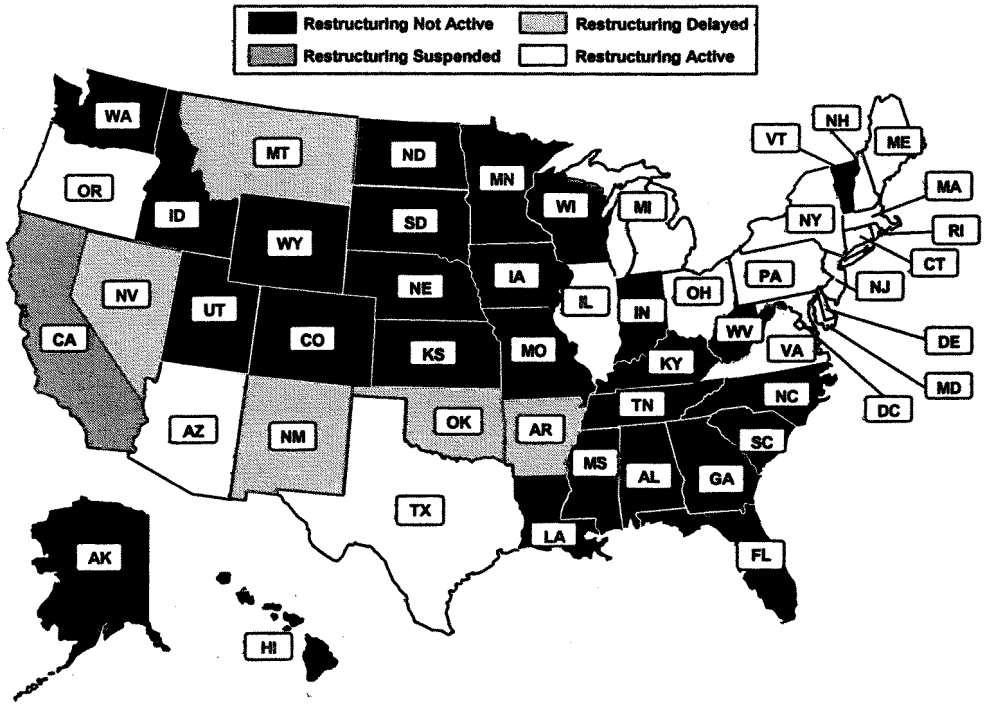
In 2001, the California spent over $10.7 billion to purchase electricity on the spot market to supply customer's daily needs. The state also signed long-term contracts worth approximately $43 billion for 10 years. These contracts represented about one-third of the three utilities' requirements for the same period (2001–2011). Viewed with the benefit of perfect hindsight, the state entered these long-term contracts when prices were at an all-time high. Future prices hovered in the range of $350–$550 per MWh during the time the State negotiated its long-term contracts and in April future prices peaked at $750/MWh as the state finalized its last contract. By August 2001, future prices had sunk below $100. Thus, as of May 2006, the state is obligated to pay well over market prices for at least 5 more years. See Southern California Edison.

The experience in California and its ripple effects in the western region prompted several states to defer or abandon their efforts to implement retail competition. Since 2000, no additional states have adopted retail competition. Indeed, some states including Arkansas and New Mexico, which had previously adopted retail competition plans, repealed them.

Other large states such as Texas, New York, Pennsylvania, New Jersey, and Illinois moved ahead with retail competition as planned. These states have ended, or are about to end, their POLR service rate caps and will soon rely on competitive wholesale and retail markets for electricity.

As shown in Figure 4–2, at present, 16 states and the District of Columbia have restructured at least some of the electric utilities in their states and allow at least some retail customers to purchase electricity directly from competitive retail suppliers. Restructured states as of April 2006 include: Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia.

Figure 4-2: United States Map Depicting States with Retail Competition, 2003



Source: EIA, available at http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf

D. Experience with Retail Competition

With these expected benefits in mind, the Task Force examined seven states in depth to report the status of retail competition. These states represent the different approaches taken to introduce retail competition. The states include Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas and they. These states are referred to as ''profiled states.''

In most profiled states, competition has not developed as expected. Few alternative suppliers currently serve residential customers. To the extent that there are multiple suppliers serving customers, prices have not decreased as expected, and the range of new options and services is limited. Much of the lack of expected benefits can be attributed to the fact that some states still have capped residential POLR rates. Commercial and industrial customers generally have more choices than residential customers because most do not have the option to take POLR service at discounted, regulated rates, have substantially larger demand (load), and have lower marketing/customer service costs.

This section first reviews the status of retail competition in the profiled states with an emphasis on entry of new suppliers, migration of customers to alternative suppliers, and the difficulties in drawing conclusions about retail competition's effect on prices. The section then discusses how regulated POLR service has distorted entry decisions of alternative suppliers. The section also discusses the lessons learned from the use of POLR that may assist states as they decide how to structure future POLR service.

1. Status of Retail Competition

a. States Have Allowed Distant Suppliers to Access Local Customers and Have Encouraged Distribution Utilities to Divest Generation

The profiles revealed that each state took some measures to encourage entry of new suppliers to compete with the supply offered by the incumbent utility. Each of the profiled states adopted policies to allow suppliers other than the local incumbent distribution utility access to local retail customers by requiring the utilities in the state to join an independent system operator (ISO) or regional transmission organization (RTO). As discussed in Chapter 3, larger wholesale electricity geographic markets enable retail suppliers and marketers to buy generation supplies from a wider range of local and distant sources (*e.g.,* neighboring utilities with excess generation, independent power producers, cogenerators, *etc.*). Even if no new generation facilities are built, independent operation and management of the transmission grid increases the choices available to retail customers and makes it more difficult for local generators to exercise market power.

Some states such as Massachusetts, New Jersey, and New York ordered or encouraged utilities to divest generation assets to independent power producers (IPP) either to eliminate possible transmission discrimination or to secure accurate stranded cost valuations.[189] These divestitures have generally not required that a utility sell its generation assets to more than one company to eliminate the potential for the exercise of generation market power, but often generating facilities have been purchased by more than one IPP.[190] In other states, such as Illinois and Pennsylvania, several utilities voluntarily divested their generation assets by selling them or moving them into unregulated affiliates.[191]

The result of these divestitures has been that regulated distribution utilities in profiled states operate fewer generation assets than in the past. Distribution utilities that are required to serve customers must access the wholesale supply market to obtain generation supply to serve their customers. Table 4–2 shows the amount of a state's generation that was under operation by the state's regulated distribution utilities (*i.e.*, in the ''rate base'') prior to retail competition and after the start of retail competition.

TABLE 4–1.—DISTRIBUTION UTILITY OWNERSHIP OF GENERATION ASSETS IN THE STATE IN WHICH IT OPERATES

State	Prior to restructuring (percent)	2002 (percent)
Illinois	97.0%	9.1%
Maryland	95.4	0.1
Massachusetts	86.6	9.0
New Jersey	81.2	6.8
New York	84.3	32.4
Pennsylvania	92.3	12.3
Texas	88.3	41.2

Source: U.S. Department of Energy, Energy Information Administration, State Profiles, Table 4 in each state profile, *available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html*. The pre-retail competition statistics are from 1997 and the post-retail competition statistics are from 2002.

Other states, such as Texas, limited the market share that any one generation supplier can hold in a region, thus providing more of an opportunity for other suppliers to enter.[192] Still others such as New York have helped organize introductory discounts from alternative suppliers, thus providing customers an incentive to switch to these new suppliers.[193]

b. Alternative Suppliers Serving Retail Customers and Migration Statistics

In the profiled states, substantial numbers of generation suppliers serve large industrial and large commercial customers. For example, in Massachusetts, over 20 direct suppliers provide service to commercial and industrial customers, along with over 50 licensed electricity brokers or marketers.[194] In Massachusetts, however, there are substantially fewer active suppliers serving residential customers—only four in Massachusetts.[195] In New Jersey, commercial and industrial customers can choose among nearly 20 suppliers, but residential customers have a choice of one or two competitive suppliers.[196]

For residential customers, Texas and New York are the two states in which more than just a handful of suppliers serve residential customers. In Texas, residential customers have approximately 15 suppliers from which to choose.[197] In New York, between six and nine suppliers offer services to residential customers in each service territory.[198] Very few, if any, suppliers provide service to residential customers in the other profiled states or in other retail competition states. One notable exception has been the municipal aggregation program in Ohio described in Box 4–4.

Box 4–4: Customer Choice Through Municipal Aggregation in Ohio

In New York, Texas, and most other states retail customer switching occurs primarily through individual customers making a choice to pick a specific alternative retail supplier. In Ohio, however, most switching activity has occurred through aggregations of customers seeking a supplier under the statewide ''Community Choice'' aggregation option. In Ohio, the retail competition law provides for municipal referendums to seek an alternative supplier and allows municipalities to work together to find an alternative supplier. The largest aggregation pool, the Northeast Ohio Public Energy council is made up of 100 member communities and serves approximately 500,000 residents. Aggregation accounts for most of the residential switching in Ohio. The Ohio program allows individual customers to opt out of the aggregation. In most other states, aggregation programs use an approach under which customers must specifically opt in to participate. Participation rates generally are much higher under opt out than under opt in programs.

In those territories with more generation suppliers, the migration or number of residential customers switching from the POLR service to an alternative competitive supplier is the greatest. For example, in Massachusetts, as of December 2005, 8.5 percent of the residential customers had migrated to a competitive supplier. Approximately 41

[189] *See* Massachusetts, New Jersey, and New York profiles, Appendix D. *See also* FTC Staff Report *Competition and Consumer Protection Perspectives on Electric Power Regulation Reform: Focus on Retail Competition* (Sept. 2001) at 43 [hereinafter FTC Retail Competition Report].

[190] The price of generation assets have been volatile since these divestitures occurred. The asset prices are often based not only to the cost of the fuel necessary to generate the electricity, but also to the location of the asset on the transmission grid.

[191] *See* Illinois and Pennsylvania profiles, Appendix D. *See also* FTC Retail Competition Report, Appendix A (State profiles of Illinois and Pennsylvania).

[192] Texas profile, Appendix D.

[193] New York profile, Appendix D.

[194] Massachusetts Department of Telecommunications and Energy, List of Competitive Suppliers/Electricity Brokers, *available at http://www.mass.gov/dte/restruct/company.htm.*

[195] Massachusetts Department of Telecommunications and Energy, Active Licensed Competitive Suppliers and Electricity Brokers, *available at http://www.mass.gov/dte/restruct/competition/index.htm#Licensed%20Competitive%20Suppliers%20and%20Electricity%20Brokers.*

[196] New Jersey Board of Public Utilities, List of Licensed Suppliers of Electric, *available at http://www.bpu.state.nj.us/home/supplierlist.shtml.* For example, in the Connectiv territory, there are 18 commercial and industrial (C&I) and 1 residential suppliers. Eighteen suppliers serving C&I customers and 1 serving residential customers in the PSE&G service territory.

[197] Texas Public Utilities Commission, Texas Electric Choice Compare Offers from Your Local Electric Providers, *available at http://www.powertochoose.org/default.asp.*

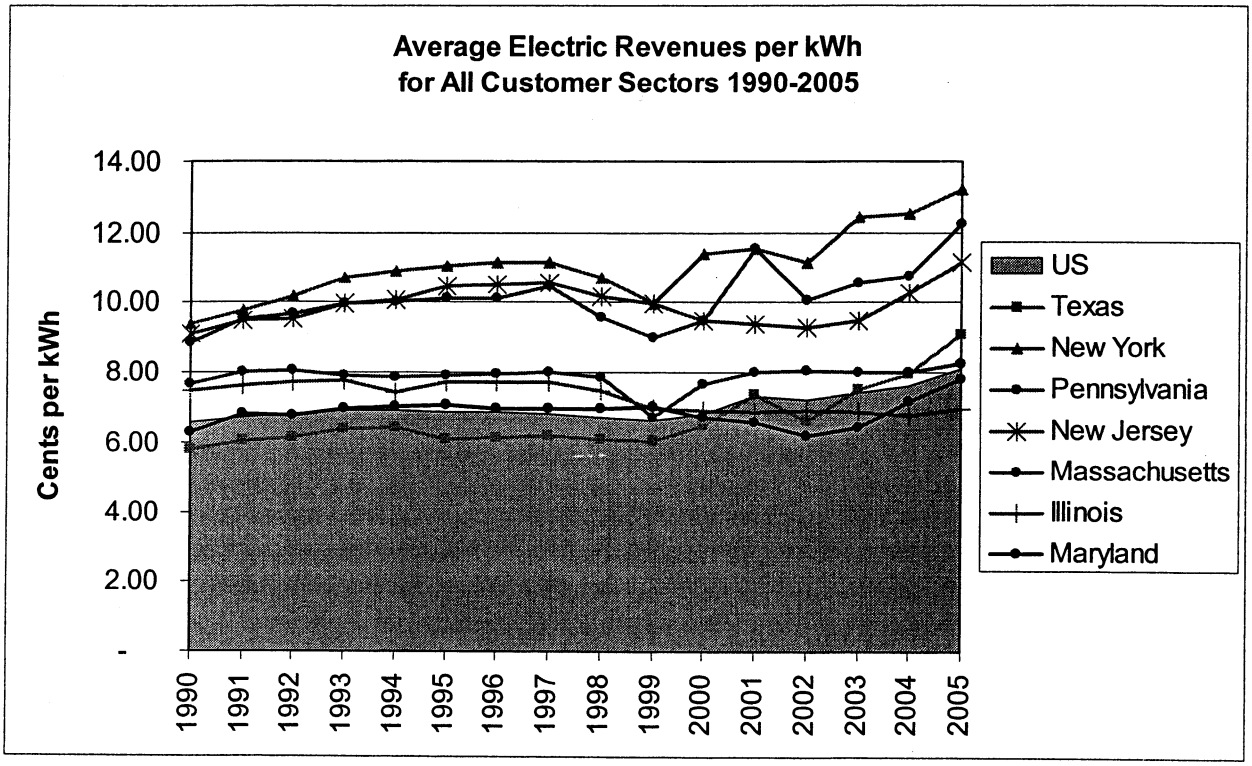
[198] New York State Public Service Commission, Competitive Electric and Gas Marketer Source Directory, *available at http://www3.dps.state.ny.us/e/esco6.nsf/.*

percent of large commercial and industrial customers had switched to alternative suppliers, representing 57.5% of the load.[199] In states with a large number of suppliers serving residential customers, higher percentages of residential customers had switched to a new supplier with approximately 26% choosing a new supplier in Texas.[200] Of course, once alternative suppliers serve customers, the local distribution utility no longer provides generation supply, but continues to deliver the generation supply over its transmission and distribution system.

c. Retail Price Patterns by Type of Customer

Figures 4–3 shows average revenues per kilowatt hour for all customer types in the profiled states against the national average for the period 1990–2005. The U.S. national average was generally flat at 8 cents per kWh during this period. New York, Massachusetts, and New Jersey have generally been higher than the national average and Texas, Pennsylvania, Maryland, and Illinois have been lower. In 2004 and 2005 retail prices in all states have begun to increase.

Figure 4-3. Average Revenues per kWh for Retail Customers 1990-2005 Profiled States vs. National Average



Source: EIA Form 861 data, and Monthly Electricity Report for average electric revenues per kWh all sectors, all retail providers.

i. Residential and Commercial Customers

It is difficult to draw conclusions about how competition has affected retail prices for residential customers in those states in which residential customers continue to take capped POLR service (*e.g.*, Maryland, Illinois, and portions of New York, Pennsylvania, and Texas). Price comparisons of regulated prices shed little light on the price patterns as a result of retail competition.

For those states in which the residential rate caps have expired, POLR prices have increased recently. In New Jersey, residential rate caps on POLR service expired in the summer of 2003. Since then, the state has conducted an internet auction to procure POLR supply of various contract lengths (one and three year contracts). The state holds annual auctions to replace the suppliers with expiring contracts and to acquire additional supply. Rates for the generation portion of POLR service were flat in 2003 and 2004 after adjusting for deferred charges, but they increased in 2005 and 2006 with rates increasing approximately 13% between 2005 and 2006.[201]

In Massachusetts, capped POLR rates expired in February 2005. Since then customers who had not chosen an alternative supplier were still able to obtain POLR service. Massachusetts based the generation portion of the POLR service on the price of supply procured in wholesale markets through fixed-priced, short-term (three or six months) supply contracts. Rates for the

[199] Massachusetts profile, Appendix D.

[200] Texas profile, Appendix D.

[201] New Jersey profile, Appendix D. *See also* Kenneth Rose, 2003 Performance of Electric Power Markets, Review Conducted for the Virginia State Corporation Commission (Aug. 29, 2003) at II–19.

generation portion of POLR service in the Boston Edison (north) territory increased from 7.5 to 12.7 cents per KWh from 2005 to 2006.[202]

ii. Large Industrial Customers

Similar to the situation described above for residential customers, large industrial customers that continue to use a fixed price POLR service shed little light on price patterns. A number of states, however, have revised their POLR policies for large customers such that the POLR price for generation is a pass-through of the hourly wholesale price for electricity plus a fixed administrative fee. For example, Maryland, New Jersey, and New York have adopted this type of POLR pricing for large industrial customers.[203] In these states, substantial numbers of customers, as described above, have switched to alternative suppliers.

Large industrial customers have cited how their rates have increased since the beginning of retail competition.[204] Indeed, some commenters suggested that the Task Force compare prices for customers of the same utility that operates in a state that did not implement retail competition to examine the effect of retail competition on rates.[205]

The difficulty with this type of comparison is that many factors simultaneously influence prices that may not be related to retail competition. For example, one state may have reduced the cross-subsidies of residential by industrial customers, and another may not have, so that a price comparison would be misleading. Access to different generators (with low or high prices) may be affected by transmission congestion such that comparing two states as if they were in the same physical location would be misleading. Finally, some states may be deferring recovery of costs to a future time period whereas other states are not. Thus, a simple price comparison may not reveal whether retail competition has benefited customers, without consideration of these and other factors. At this point it is difficult for the Task Force to provide a definitive explanation of price differences between states.

d. Results of Efforts To Bring Accurate Price Signals Into Retail Electric Power Markets

The impact of retail competition to bring efficient price signals to retail customers has been mixed. Residential POLR service rate caps have not increased customer exposure to time-based rates. The exception has been real-time pricing as the POLR service for the largest customers in New Jersey, Maryland, and New York.

Commenters argue that POLR rate structure can have a major effect on customer price responsiveness, especially among larger customers. A broad spectrum of utilities, state regulators, and ISOs argue that variable rates permit customers to react to price changes because these rates allow customers to clearly see how much money they can save.[206] Indeed, the experience of the largest customers in National Grid USA's New York area, suggests that after the introduction of retail competition, customers using real-time pricing demonstrate price sensitivity.[207]

In states with traditional cost-based regulation, utilities have used various incentives for customers to reduce consumption during periods in which there is high demand and transmission congestion (*e.g.*, hot summer days). The existence of retail competition has, in some instances, discouraged the use of these traditional types of programs, particularly when POLR is no longer the responsibility of distribution utilities.[208] Without the need to maintain a portfolio of resources to meet POLR, distribution utilities may no longer value these types of programs as a resource to ensure reliable and efficient grid operation. Shifting the responsibility of grid operation and reliability to regional organizations such as ISOs/RTOs further decreases the direct interest by distribution utilities in these types of product offerings.

e. Retail Competition and Rural America

Many rural areas are served by small non-profit electric cooperative and public power utilities. Historically rural areas were among the last to be electrified and the most costly to serve. Customers are scattered and residential and small loads predominate. Electric distribution cooperative service areas have been opened to competition under some state plans. No states have required municipal and/or public power utilities to implement retail competition.

Eight states with retail competition required electric cooperatives to implement retail competition in their service territories. These states are Arizona, Delaware, Maine, Maryland, Michigan, New Hampshire, Pennsylvania and Virginia. With the exception of Pennsylvania, state public utility commissions regulated retail rates of electric cooperatives and approved the retail competition plans for each cooperative. Pennsylvania's restructuring legislation left the design and implementation of retail competition to the individual distribution cooperatives and their boards. The Pennsylvania Public Utility Commission is responsible for licensing competitive retail providers in cooperative service territories. Cooperative retail competition plans have been fully implemented in Delaware, Maine, New Hampshire, Pennsylvania, and Virginia. In Arizona and Michigan some aspects of cooperative retail competition plans are still in administrative or judicial proceedings. Michigan currently has allowed electric cooperatives to offer retail competition to a portion of their very large industrial and commercial customers. Action on extending competition to other customers in Michigan has been deferred.

Six more states allow electric cooperatives to opt in to retail competition on a vote of their boards or membership. These are Illinois, Montana, New Jersey, Ohio, and Texas. None of these states regulate the rates or services of electric distribution cooperatives, so design and implementation of cooperative retail competition plans is left to the individual cooperative. Licensing of competitive providers is handled by the state, but providers must enter into agreements with the cooperative in order to begin enrolling retail customers. A handful of individual cooperatives in Montana and Texas elected to provide retail competition options for their members.

Tracking the progress of retail competition in rural areas is difficult because most states do not post switching data or maintain up to date information on active suppliers in cooperative service territories. Nevertheless, it was possible to determine that there were few alternative competitive providers, if any, for residential customers of rural systems open to retail competition. There were no competitive providers enrolling customers in coop systems in

[202] Massachusetts profile, Appendix D.

[203] Although POLR price is based on the hourly wholesale price of electricity, customers in New York and New Jersey who purchase this service are unaware of the price until they are billed.

[204] *See, e.g.*, ELCON; Portland Cement; Alliance of State Leaders; Alcoa.

[205] Portland Cement; Lehigh Cement.

[206] Constellation, PEPCO, Southern and EEI, ICC, IURC, and NYPSC, ISO–NE.

[207] National Grid.

[208] For example, when PEPCO divested its generation assets it stopped actively supporting its air-conditioner DLC program.

Maine, New Hampshire, Pennsylvania, Arizona, Maryland, and Virginia in May 2006. In Delaware, and Montana, competitive providers had been licensed to serve coop customers, but it is unclear that any are currently enrolling customers. Licensed provider and switching information for Texas cooperatives is not yet available.

B. POLR Service Price Significantly Affects Entry of New Suppliers

Each of the profiled states has required local distribution utilities to offer a POLR service for customers who do not select an alternative generation service provider or whose supplier has exited the market. The price that the distribution utility charges for regulated POLR service is usually ''fixed'' for an extended period—that is, it does not vary with increases or decreases in wholesale prices. The most significant portion of the POLR service price is the generation portion of the POLR service. Many states denote this as the ''price to beat'' or the ''shopping credit.'' It also represents the amount that the customer avoids paying the distribution utility when the customer chooses an alternative generation service provider. The customer instead pays the alternative electricity supplier's charges for generation services.

The comments reported that the price of POLR service is the most significant factor affecting whether new suppliers will enter the market and compete to serve customers.[209] The POLR price is the price that new suppliers, including unregulated affiliates of the distribution utility, must compete against if they are to attract customers.[210]

1. Contrasting Visions of POLR Service

The comments revealed two long-term visions of POLR service. In the first vision, POLR is a long-term option for customers. In the second vision, POLR is a temporary service for customers between suppliers. The first vision entails POLR service that closely approximates traditional utility service, but in a market place with other sources of supply available to customers. POLR service under the first vision often features prices that are fixed over extended periods of time. In this vision, government-regulated POLR service competes head-to-head with private, for-profit retail suppliers.[211] An analogous example may be the United States Postal Service as a provider of parcel postage service in competition with for-profit, package delivery services such as United Parcel Service, DHL, and Federal Express. Alternative suppliers may grow in this vision as they find additional approaches to attract customers, but POLR service will likely retain a substantial portion of sales, particularly sales to residential customers. This type of POLR service serves as a yardstick against which alternative suppliers compete. Most states have used this version of POLR.[212]

In the second vision, POLR service is a barebones, temporary service consisting of retail access to wholesale supply, primarily for customers who are between suppliers. In this vision, alternative suppliers serve the bulk of retail customers. The alternative suppliers compete primarily against each other with a variety of price and service offers designed to attract different types of customers. This type of POLR service acts as a stopgap source of supply that ensures that electric service is not interrupted for customers when an alternative supplier leaves the market or is no longer willing to serve particular customers. Wholesale spot market prices or prices that vary with each billing cycle may be acceptable as the price for POLR service under this vision.[213] A comparable supply arrangement for this version of POLR service is the high risk pool for automobile insurance operated in any of several states.[214] Texas and Massachusetts provide current examples of this vision, as is Georgia in its design for retail natural gas sales.[215]

Some of profiled states incorporated aspects of both visions of POLR service for different types of customers. For example, New Jersey adopted the first approach for POLR service to residential customers and the second approach for POLR service to large commercial and industrial customers.[216] Large C&I customers are generally expected to be well-informed buyers with wide energy procurement experience. As such, some states determined that large C&I customers are more likely to be able to quickly obtain the benefits of retail competition without additional help from state regulators provided in the form of fixed price POLR prices.

2. Key POLR Service Design Decisions

The profiled states took different approaches to design their POLR service offerings. Key design decisions involved the pricing of the POLR, how to acquire POLR supply, and the duration of the POLR obligation. Each of these can affect entry conditions that alternative suppliers face. This section describes each of the decisions.

a. Pricing of POLR Service

The profiled states generally set the POLR price at the pre-retail competition regulated price for electric power less a discount. The discounts usually persist over a specified multi-year period. Assuming that competition generally lowers prices, one rationale for the discounts was to provide a proxy for the effects of competition applied to customers viewed as less likely to be

[209] The comments also identified other factors that depress or delay entry into retail competition markets besides the policies surrounding POLR discussed above. It is difficult for the Task Force to evaluate which additional factors are the most important because of the lack of entry in most states. For example, the Pennsylvania Consumer Advocate identified several factors that depressed retail entry by suppliers to serve residential customers, including ''the acquisition costs associated with marketing programs to reach residential customers, the costs of serving such customers once acquired, and the rising prices for generation supply service in the wholesale market'' PA OCA at 3. The Maine Public Advocate echoed these and identified the ''miscalculation by some suppliers as to the risks and rewards for retail electricity competition'' ME PA at 3. The Industrial Customers identified that retail markets are not fully competitive because of the insufficient generation divestitures that left suppliers with market power. ELCON at 2. Other factors identified by Industrial Customers include inability of alternative suppliers to gain access to necessary transmission services to serve their customers. ELCON at 6. Others customers suggested the lack of uniform rules throughout every service territory hinder ease of entry for suppliers. Wal-Mart at 13. Other commenters argued that alternative suppliers need access to customer usage data from utilities to be able to market to prospective customers. Constellation at 43. Still others argued for no minimum stay requirements at POLR and constrained shopping windows, which can dampen entry. RESA at 30–31, Strategic at 10, Wal-Mart at 13.

[210] There is one potential exception. Suppliers that offer a substantially different product, ''green'' power from wind turbines, for example, may be able to charge a higher price and still attract customers.

[211] *See, e.g.*, ICC, PPL, and PA OCA.

[212] *See, e.g.*, PA OCA; NASUCA.

[213] *See, e.g.*, RESA, Wal-Mart, NEMA, and Suez.

[214] Most states have a mechanism by which high risk drivers can obtain insurance. Often insurers in a state are assigned a portion of the pool of high risk drivers based on that firm's share of drivers outside the pool. AIPSO manages many of the pools and maintains links with individual state programs at *https://www.aipso.com/adc/DesktopDefault.aspx?tabindex=0&tabid=1*. Similar plans are available in many states for individuals with prior health conditions who are seeking health insurance coverage. *See* Communicating for Agriculture and the Self-Employed, *Comprehensive Health Insurance of High-Risk Individuals*, 19th Ed. (2005).

[215] Texas will end its ''price to beat'' system in 2007 (Texas profile). Massachusetts ended its rate-capped POLR service in February 2005 (Massachusetts profile). In the Atlanta Gas Light distribution territory, the distribution utility petitioned the Georgia Public Service Commission to withdraw from retail sales. In Georgia, under the amended Natural Gas Competition and Deregulation Act of 1997, a customer who does not choose as alternative supplier is randomly assigned to an alternative supplier. Discussion and documentation about the Georgia natural gas retail competition program are *available at http://www.psc.state.ga.us/gas/ngdereg.asp*.

[216] New Jersey profile, Appendix D.

able to quickly obtain such savings for themselves. The Illinois POLR service discount, for example, was developed to bring local prices into line with regional prices. Those customers in areas with relatively low prices before customer choice did not receive discounts below previous regulated rates at the beginning of retail competition. In contrast, customers in the Commonwealth Edison territory, the area with the highest cost-based rates, received 20% discounts to bring retail POLR prices there into line with regional average bundled service prices prior to the restructuring legislation.[217]

b. The Extent and Timing of Pass Through of Fuel Cost Changes

States also have considered the extent to which they should adjust the regulated POLR price to allow for changes in fuel costs to generate electricity. Some states have separated fuel costs from other cost components, because fuel costs have been more volatile than other input prices—they are the largest variable cost component, and can be calculated for each type of generation unit, based on public information. These factors also suggest that a generation firm does not have much control over its fuel costs once the generation investment has been made. For example, Texas instituted twice yearly adjustments in the POLR service (price to beat) price calculations. By adjusting POLR prices for changes in fuel costs, the Texas regulators have been able to prevent the POLR price from slipping too far away from competitive price levels, thus maintaining the POLR price as a closer proxy for the competitive price.[218] If retail prices fall too far below wholesale prices, the POLR supplier may have financial difficulties and alternative suppliers will be unlikely to enter or remain as active retailers.[219]

c. POLR Price and the Shopping Credit

When a retail customer picks an alternative supplier, the distribution utility with a POLR obligation avoids the costs of procuring generation supply for that consumer. The distribution utility therefore ''credits'' the customer's bill so that the customer pays the alternative supplier for the electricity supplied.[220] This avoided charge is known as the shopping credit and is equal to the regulated POLR service price. States have used two approaches to determine the level of the shopping credit. One view is that the shopping credit equals the avoided cost or the proportion of POLR procurement costs attributable to a departing customer. Maine, for example, has estimated avoided costs on this basis with no additional estimated avoided costs.[221] This view results in a lower shopping credit and total POLR price. An alternative perspective is that the distribution utility also avoids other costs on top of avoided procurement costs, including marketing and administrative costs.[222] This view results in a higher shopping credit and total POLR price. In Pennsylvania, the POLR shopping credit included several other elements such as avoided marketing and administrative costs.[223] Some observers attributed the early high volume of switching to alternative suppliers in Pennsylvania to the additional avoidable costs that were included in the Pennsylvania shopping credit calculations.[224]

d. The Multi-Year Period for POLR Service

Every state that implemented retail competition has determined the length for which POLR should continue to be available to customers at a discount from prior regulated prices. The length of this period has generally corresponded to the distribution utility's collection of ''stranded'' generation costs. In a competitive retail environment, utilities no longer were assured that they could recover the costs of all of their state-approved generation investments. Most states faced claims of utility stranded costs associated with generation facilities that were unlikely to earn enough revenues to recover fixed costs once customers can seek out alternative, lower-priced retail suppliers. States allowed utilities with stranded costs to recover those costs through charges on distribution services that cannot be bypassed.[225]

Each state that authorized the collection of stranded costs faced decisions on how to determine these costs and the duration of the collection period. These decisions fundamentally altered the electric power industry and were at the center of some of the most contentious issues facing state regulators. First, some states required that some or all generation be sold to obtain a market-based determination of the level of stranded costs. For example, Maine and New York took this approach.[226] In other states, such as Illinois, utilities voluntarily divested generation assets. As noted above, the result of these divestitures is that generation is no longer primarily in the hands of regulated distribution utilities.[227]

e. Procurement for POLR Service

Given that most utilities no longer own generation to satisfy all of their POLR obligations, utilities have taken different approaches to acquire the necessary generation supply. For example, the utilities in New Jersey that offer residential POLR service acquire the generation supply through the use of three overlapping 3-year contracts, each for approximately one third of the projected load.[228] This ''laddering'' of supply contracts reduces the volatility of retail electricity prices for customers, but it does not assure that the prices paid by POLR service consumers are at the short-term competitive level.[229] Other states have used different ways to hedge the volatility in short-term energy prices. For example, New York distribution utilities have long-term supply contracts with the purchasers of their divested generation assets (''vesting contracts'') based on pre-divestiture average generation prices.[230]

E. Observations on How POLR Service Policies Affect Competition

One of the most contentious issues currently facing state regulators is whether and how to price POLR service once the rate caps expire. This situation is especially vexing for those states that had stranded cost recovery periods

[217] Illinois profile, Appendix D.

[218] Texas profile, Appendix D.

[219] *See* discussion of the California energy crisis in which one of the state's utilities declared bankruptcy because, in part, capped POLR rates were substantially below wholesale prices.

[220] The distribution utility continues to charge the customer a delivery charge to cover the transmission and distribution expense (the ''wires'' charge).

[221] Thomas L. Welch, Chairman, Maine Public Utilities Commission, UtiliPoint PowerHitters interview (January 24, 2003), *available at http://mainegov-images.informe.org/mpuc/staying_informed/about_mpuc/commissioners/ph-welch.pdf.*

[222] *See* Kenneth Rose, *Electric Restructuring Issues for Residential and Small Business Customers*, National Regulatory Research Institute Report NRRI 00–10 (June 2000), *available at http://www.nrri.ohio-state.edu/dspace/bitstream/2068/610/1/00–10.pdf*, for a discussion of adders and their relationship to wholesale prices and headroom for entrants in Pennsylvania and other states.

[223] *Id.*

[224] Over time, the size of the shopping credit in Pennsylvania faded in significance as the competitive rates increased relative to POLR service prices due to fuel cost increases. See the pattern of customer switching in the Pennsylvania profile in the appendix.

[225] FTC Retail Competition Report, State Profiles, Appendix A.

[226] New York profile, Appendix D; FTC Retail Competition Report, New York State Profile, Appendix A.

[227] Illinois profile, Appendix D.

[228] New Jersey profile, Appendix D.

[229] *See, e.g.*, ME OPA.

[230] New York profile, Appendix D.

during which fixed POLR prices became substantially lower than current wholesale prices. The rate caps expire in 2006 for states such as Maryland, Delaware, Illinois, Ohio, and Rhode Island, and customers that did not choose an alternative supplier are faced with the prospect of substantially increased electricity prices relative to those in effect when retail competition began six or seven years ago. The various state POLR policies show the range of options available to these states.

1. POLR Service Price to Approximate the Market Price

For the POLR service price to provide economically efficient incentives for consumption and supply decisions, it must closely approximate or be linked to a competitive market price based on supply and demand at a given point in time. If the POLR service price does not closely match the competitive price, it is likely to distort consumption and investment decisions away from theoretically optimal allocation of electricity resources. Theoretically, competitive market prices align consumers' willingness to pay for a service with a suppliers cost of supply (where, in the long run, cost includes a fair market return on investment). This alignment is thought to lead to an economically efficient allocation of resources, wherein no alternate distribution of resources could lead to greater benefits to society as a whole.

Experience within the profiled states shows that approximating the competitive price is not an easy task. Not only does the competitive price change when prices of inputs change, but the price also acts as an investment signal for new generation. The competitive price can quickly and dramatically move. Over the past several years, the initial fixed discounts for POLR service have resulted in POLR service prices that are below market prices or occasionally above market prices, but never at the market price for long.[231] When the POLR prices are below competitive levels, even efficient alternative suppliers cannot profit by entering or continuing to serve retail customers.[232] Firms with the POLR obligation can become financially distressed, as they did in California during its energy crisis.[233]

Some of the change in the market price is likely to be due to changes in fuel prices. A POLR service design that adjusts the retail electricity price for changes in the prices of fuels used by marginal generators makes a better proxy for the market price than one that is fixed. When the POLR price is adjusted to incorporate underlying fuel price changes, but it is adjusted infrequently, the POLR price can repeatedly change from being above the competitive market price to below the competitive market price.[234] In this way, a fixed price creates incentives for customers to move back and forth from POLR service to alternative suppliers. This repeated switching can create additional costs for both POLR service providers and alternative suppliers and it can reduce the certainty that both POLR service and competitive suppliers may need in order to make long-term supply arrangements. If there are other identifiable cost components that fluctuate widely, including them in POLR service price adjustments will also increase the likelihood that the POLR service price will be a reasonable proxy for the competitive price.

2. Lack of Market-Based Pricing Distorts Development of Competitive Retail Markets

A second issue arises when below-market POLR service prices persist during a period of rising fuel prices and wholesale supply prices. In these circumstances, customers are likely to experience a shock when POLR service prices are adjusted to match prevailing wholesale prices. This situation can create public pressure to continue the fixed POLR rates at below-market levels. For example, some jurisdictions have considered a gradual phase-in of the price increase to bring POLR prices to the market level. The shortfall between the market POLR price and the price customers pay is usually deferred and collected later from the POLR provider's customers.

Although this approach reduces rate shock for customers, it is likely to distort retail electricity markets. First, a phase-in continues to provide inaccurate price signals for customers and undermines incentives to reduce consumption or to conserve electric power use. Second, it prevents entry of alternative suppliers by keeping the POLR rate below market for additional years. Third, it results in higher prices in future years as the deferred revenues are recovered. Fourth, if surcharges to pay for deferred revenues are not designed carefully, the charges can disrupt existing competition by forcing customers with alternative suppliers to pay for part of the deferred revenues. Fifth, if wholesale prices decline, customers will choose alternative suppliers and this migration will create a stranded cost problem because the POLR provider will have lost customers who were counted on to pay the higher prices. Moreover, if the state prevents the stranded cost problem by imposing large exit fees on POLR service customers, competition may not develop even after POLR service prices rise to market levels because POLR service customers will be locked in to the POLR provider. Finally, continued POLR service price caps in an environment of increasing wholesale price increases can endanger the financial viability of the distribution utility.

3. Different POLR Services Designed for Different Classes of Customer

Some states have different POLR service designs for different customer classes. POLR service prices offered to large C&I customers generally have entailed less discounting from regulated rates or competitive market-based procurement and have been based on wholesale spot market prices.

Large C&I customers generally have a better understanding of price risk, the means to reduce it, and the costs to reduce it than do other customer classes. In addition, suppliers often can customize service offerings to the unique needs of these large customers.[235] Large C&I customers, with their larger loads, also may be better equipped to respond to efficient price signals than other classes of customers. The result of this price response may be to improve system reliability and dissipate market power in peak demand periods.[236]

In states in which this division between POLR service for large C&I customers and POLR service for residential and small C&I customers has been implemented, there has been more switching to competitive providers among large C&I customers.[237] Many alternative suppliers have reportedly developed customized time of use

[231] *See, e.g.*, Wal-Mart; WPS Resources; ICC; PPL; RESA.

[232] *See, e.g.*, Wal-Mart; RESA.

[233] *See, e.g.*, EEI.

[234] *See, e.g.*, RESA.

[235] *See, e.g.*, Wal-Mart and 10–11; Morgan.

[236] In case 03–E–0641, the New York Public Service Commission required New York utilities to file tariffs for mandatory real-time pricing (RTP) for large C&I customers. The order observed that ''average energy pricing reduces customers' awareness of the relationship between their usage and the actual cost of electricity, and obscures opportunities to save on electric bills that would become apparent if RTP were used to reveal varying price signals.'' It further notes that ''if a sufficient number of customers reduced load in response to RTP, besides benefiting themselves, the reduction in peak period usage would ameliorate extremes in electricity costs for all other customers.''

[237] New Jersey profile, Appendix D; RESA.

contracts for large C&I customers.[238] Moreover, the profiled states show that there are a substantial number of suppliers actively serving large C&I customers. Box 4–5 describes the unique sign-up period that Oregon has developed for its non-residential customers.

Box 4–5: Oregon's Annual Window for Switching for Nonresidential Customers

Nonresidential customers of the two large investor-owned distribution utilities in Oregon can switch to an alternative supplier, but the switching process is unique. Nonresidential customers must make their selections during a limited annual window. The window must be at least 5 days in duration, but usually a month is allowed. In addition to picking the alternative supplier, the largest customers must select a contract duration. One option specifies a minimum duration of 5 years, with an annual renewal after that. As of 2005, alternative suppliers were anticipated to serve about 10% of load in one distribution area and about 2.1% in the other. The former utility offered choice beginning in 2003. The latter utility began customer choice in 2005. Detailed descriptions are available at *http://www.oregon.gov/PUC/electric_restruc/indices/ORDArpt12-04.pdf*.

Exposure of all customers to time-based prices is not necessary to introduce price-responsiveness into the retail market.[239] As a first step, customers who are the most price-sensitive and elastic could be exposed to time-based rates. Niagara Mohawk in upstate New York has taken this approach for its largest customers, as have Maryland and New Jersey for their largest customers. California is considering setting real-time pricing as the default rate for medium-sized and larger commercial and industrial customers. Another means to introduce price-responsiveness is to provide customers voluntary time-based rate programs, along with assistance in equipment purchase or financing. The actions of the New York PSC to require voluntary TOU for residential customers, and the Illinois legislature to require that residential customers be offered real-time pricing as a voluntary tariff are examples of such a policy. Of course, the point is that competition will provide customers with the mix of products and services that match their needs and preferences—not a determination of the popularity of real-time pricing.

4. Use of Auctions To Procure POLR Service

As discussed above, New Jersey has used an auction process to procure POLR supply for both residential and C&I customers. Illinois has proposed to use a similar auction when its rate caps expire. Auctions may allow retail customers to obtain the benefit of competition in wholesale markets as suppliers compete to supply the necessary load. However, as discussed in Chapter 3, if there is a load pocket, use of an auction is unlikely to help this process and thus the benefits of competition may not be as great.

5. Consumer Awareness of Customer Choice and Engendering Interest in Alternative Suppliers

Observers of restructuring in other industries have found that the growth of customer choice can be a slow process. A commonly cited example is that it took 15 years before AT&T lost half of long-distance service customers to alternative suppliers.[240] One reason why retail competition could be slow to develop is that the expected gains from learning more about market choices are too small to make it worthwhile to learn.[241] Residential customers with small loads might be in this position in states with retail customer choice.[242]

The pricing of POLR service and aid in computing the ''shopping credit'' may be elements that can encourage more rapid development of retail competition by making the rewards for active search sufficient to motivate search behavior by residential consumers. Some states that have low ''shopping credits'' have had little retail entry. Some retail competition states have had substantial consumer education programs, including Web sites with orientation materials and price comparisons.[243] These efforts minimize the cost of learning more about the market and about market alternatives and can, therefore, make market search beneficial to customers.

New York has engaged in a different approach to encourage the development of retail competition. It is helping to organize temporary discounts from alternative suppliers and ordering distribution utilities to make these discounts known to consumers who contact the distribution utility.[244] These efforts have increased residential switching and reduced prices, at least for the short term. Experience indicates that once residential customers switch to alternative suppliers, they seldom return to POLR service once the temporary discounts no longer apply.[245]

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[238] *See, e.g.*, Consolidated Edison; Alliance for Retail Energy Markets; Constellation; PPL; RESA; NY PSC; Direct Energy; Reliant; PA OCA; Wal-Mart; Morgan.

[239] Steven Braithwait and Ahmad Faruqui, *The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response*, PUBLIC UTILITIES FORTNIGHTLY, March 15, 2001.

[240] James Zolnierek, Katie Rangos, and James Eisner, Federal Communication Commission, Common Carrier Bureau, Industry Analysis Division, *Long Distance Market Shares, Second Quarter 1998* (September 1998), pp. 19–20, available at *http://www.fcc.gov/Bureaus/Common_Carrier/Reports/FCC-State_Link/IAD/mksh2q98.pdf*, and Thomas L. Welch, Chairman, Maine Public Utilities Commission, UtiliPoint PowerHitters interview (January 24, 2003) available at *http://mainegov-images.informe.org/mpuc/staying_informed/about_mpuc/commissioners/ph-welch.pdf*.

[241] Economists refer to this phenomenon as rational ignorance. Clemson University, *The Theory of Rational Ignorance*, The Community Leaders' Letter, Economic Brief No. 29, available at *http://www.strom.clemson.edu/teams/ced/econ/8-3No29.pdf*.

[242] Joskow, Interim Assessment.

[243] *See, e.g.*, ELCON; Progress Energy; Constellation; PEPCO; PA OCA.

[244] In Case 05–M–0858, the New York Public Service Commission adopted the ''PowerSwitch'' alternative supplier referral program, first developed by Orange and Rockland, as the model for all state utilities.

[245] New York State Consumer Protection Board, Comment to the New York State Public Service Commission, Case 05–M–0334, Orange and Rockland Utilities, Inc., Retail Access Plan (May 2, 2005) at 5. The Board indicates that retail customers who have participated in ''PowerSwitch'' are returning to POLR service at a rate of less than 0.1% per month. The Board applauds PowerSwitch because it is completely voluntary and provides assured initial savings to consumers.

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8183–6]

Science Advisory Board Staff Office; Advisory Council on Clean Air Compliance Analysis; Notification of a Public Advisory Committee Meeting (Teleconference)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA or Agency), Science Advisory Board (SAB) Staff Office announces a public teleconference for the Advisory Council on Clean Air Compliance Analysis.

DATES: The teleconference will take place on June 29, 2006 from 1 p.m. to 3 p.m. (Eastern Time).

FOR FURTHER INFORMATION CONTACT: Any member of the public who wishes to obtain the teleconference call-number and access code must contact Dr. Holly Stallworth, Designated Federal Officer (DFO), EPA Science Advisory Board