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Deregulation and Regulatory Reform in the U.S. Electric Power Sector

by

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REVISED DISCUSSION DRAFT
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ABSTRACT

This paper discusses the evolution of wholesale and retail competition in the U.S. electricity sector and associated industry restructuring and regulatory reforms. It begins with a discussion of the industry structure and regulatory framework that characterized the U.S. electric power industry during most of the 20th century and reviews the initial efforts to open the electricity industry to competitive suppliers of generating services during the 1980s and early 1990s. The economic and political pressures that emerged in the early 1990s for more fundamental reforms are discussed, including the stranded cost issue and its resolution. The architecture of the basic reform model that supports both wholesale and retail competition in the supply of generation services adopted by a number of pioneer states is developed. Recent trends in generation divestiture, mergers between electric utilities, and between electric and gas pipeline and distribution companies, and entry of unregulated merchant generating plants are then reviewed. The new institutional arrangements necessary to govern access to and the operations of electric transmission networks to support competition among competing decentralized generators of electricity are examined. Transmission pricing, market organization, congestion management and market power issues are included in this analysis. The structure and performance of California's competitive electricity markets are discussed in detail as an example of the applications of these principles and the challenges that electricity sector restructuring must confront. Early experience with retail competition in California, Massachusetts, and Pennsylvania is reviewed. The paper concludes with an initial assessment of the benefits and costs of electricity sector restructuring to date in the U.S. and some thoughts regarding future challenges and trends.

[1] Prepared for the Brookings-AEI Conference on Deregulation in Network Industries, December 9-10, 1999. I am grateful to Alvin Klevorick, Alfred Kahn, David Newbery, Elizabeth Moler, John Rowe, Mathew White, Sam Peltzman and Cliff Winston for comments on an earlier draft of this paper. I want to thank J. J. Prescott and Margaret Kyle for their assistance with my research. I am grateful for research support from the MIT Center for Energy and Environmental Policy Research.

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INTRODUCTION

The U.S. electric power sector is in the midst of major changes in its structure, the way that it is regulated, and the role that competition plays in allocating resources to and within the sector. The reforms that are now taking place are more radical than many had anticipated only a few years ago; and the pace of change is accelerating. The purpose of this paper is to address the nature and origins of these changes and to provide an initial assessment of their costs, benefits, future trends and unresolved issues.

The paper begins with a discussion of the industry structure and regulatory framework that characterized the U.S. electric power industry during most of the 20th century and the economic performance of the sector during the post World War II period. It goes on to discuss the initial efforts to open the electricity industry to competitive suppliers of generating services during the 1980s and early 1990s. A more detailed discussion of the traditional industry structure, its regulation, and early initiatives to introduce competition can be found elsewhere (Joskow and Schmalensee (1983), Joskow (1989), and Joskow (1997)). I then turn to a discussion of the economic and political pressures that emerged in the early 1990s for more fundamental reforms that focused on increasing the role of competition in the supply of electric generation services. This discussion develops the architecture of the basic reform model that supports both wholesale and retail competition in the supply of generation services adopted by a number of pioneer states, supporting changes in federal regulation, and examines recent trends in generation divestiture, mergers between electric utilities, and between electric and gas pipeline and distribution companies.

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An important aspect of this reform process is the development of new institutional arrangements to govern access to and the operations of electric transmission networks that provide the essential platform supporting competition among competing decentralized generators of electricity. Accordingly, I discuss a number of the major institutional design and market structure issues associated with the operation of transmission networks and competitive wholesale markets with good performance attributes. In order to provide a concrete example of the nature and complexity of the task of designing and implementing transmission network access and wholesale market reforms with good performance attributes, I discuss the structure and performance attributes of the transmission network and wholesale power market institutions that began operating in California in early 1998. California provides an interesting case study of the prospects and problems associated with the creation of decentralized wholesale markets for electricity. Similar network and market governance arrangements have been introduced in New England, New York, and the Pennsylvania-New Jersey-Maryland (PJM) region.

The paper then turns to a discussion of the early experience with retail competition in California, Massachusetts, and Pennsylvania. Electricity sector reform is unusual in that the stimulus for the most radical reforms has come from the states rather than from the federal government, though federal regulators and Congress have played an important supporting role. One result of this state-by-state process is that reform is moving at very different paces in different regions of the country despite the fact that electricity trading regions encompass large geographic areas covering many states. In some cases, retail competition initiatives are moving forward faster than the wholesale market and transmission reforms that are necessary to support an efficient retail competition regime. This mismatch between wholesale and retail market reforms can lead to performance problems.

I conclude with an initial assessment of electricity sector restructuring in the U.S. and a discussion of pending issues and future trends.

GOVERNANCE STRUCTURES IN ELECTRICITY

This section is designed to provide some technical, economic and institutional background for those who are not familiar with the attributes of electricity supply and demand and the way the electricity sector has been organized and regulated in the U.S.

Readers familiar with the electricity industry may productively go directly to the next section.

a. Basic Physical and Economic Attributes of Electricity Supply and Demand:

The supply of electricity is generally divided into three or four separate functions:

1. The generation (**G**) of electricity using falling water, internal combustion engines, steam turbines powered with steam produced with fossil fuels, nuclear fuel, and various renewable fuels, wind driven turbines, and photovoltaic technologies. In most developed countries there are typically many generating plants in service dispersed over a large geographic area.
2. The distribution (**D**) of electricity to residences and businesses at relatively low voltages using wires and transformers along and under streets and other rights of way.
3. Related to distribution, a set of power procurement and retailing (**R**) functions. They include making arrangements for supplies of power from generators, metering, billing, and various demand management services. The dividing line between distribution and retailing is still murky and controversial.
4. The transmission (**T**) of electricity involving the "transportation" of electricity between generating sites and distribution centers, the interconnection and integration of dispersed generating facilities into a stable synchronized network, the scheduling and dispatching of generating facilities that are connected to the transmission network to balance demand and supply in real time, and the management of equipment failures, network constraints, and relationships with other interconnected networks.

The attributes of electricity demand, electricity supply, and physical constraints associated with the operation of synchronized alternating current (AC) networks are highly relevant for understanding the organizational structure of the electric power sector that has evolved over the last century. These attributes are also highly relevant for designing transmission network and competitive wholesale power market institutions with good performance attributes. Electricity usually cannot be stored or inventoried economically, and demand varies widely from hour to hour during an individual day and from day to day over the year. The aggregate short run elasticity of demand is very small. Moreover, there is generally no meaningful direct physical relationship between a specific generator and a specific customer and no way to curtail an individual customer's consumption when specific generators fail to perform. Electricity consumed at a specific point in time must be manufactured in a generating plant virtually contemporaneously with its consumption. Since consumers continue to draw power as long as the circuits are closed and they are connected to the network, the aggregate generation of electricity and the consumption of electricity must be balanced continuously for the entire network to meet certain physical constraints (frequency, voltage, stability) on network operations.

A modern AC transmission network makes it possible to utilize generating facilities dispersed over wide geographic areas efficiently in real time to meet continually changing demand levels through the substitution of increased production from low marginal cost facilities (say in New Mexico) for production from high marginal cost facilities (say in California). In principle, an efficiently operated network would constantly equate the marginal costs of supplying an additional kWh of energy at all generating nodes adjusted for marginal losses, thermal and operating constraints throughout the network. It would also economize on the reserve capacity required for any given level of reliability (responses to equipment outages and unanticipated swings in demand) by effectively aggregating loads and reserve generating capacity over a wide geographic area and by providing multiple linkages between loads and resources that can provide service continuity when transmission facilities fail. To accomplish these tasks, the network must be operated to maintain its frequency and voltage parameters within narrow bands and to respond to rapidly changing system conditions on the demand and supply sides, especially short term demand swings and unplanned equipment outages. Generating facilities must be called upon almost continuously to provide a variety of network support services in addition to providing energy to run customer appliances and equipment. These “ancillary services” include spinning reserves, standby reserves, blackstart capability, frequency regulation (Automatic Generation Control), scheduling and dispatch control, and others.

Electric power networks are not switched networks like railroad or telephone networks where a supplier makes a physical delivery of a product at point A that is then physically transported to a specific customer at point B. A free-flowing AC network is an integrated physical machine that follows the laws of physics (Kirchoff's Laws), not the laws of financial contracting. Electricity produced by all generators goes into a common pool of electric energy and demand by consumers draws energy out of that common pool. The network operator must ensure that the pool stays filled to a constant level, balancing inflows and outflows. The electric energy produced by a particular generator cannot be physically associated with the electricity consumed by a particular consumer. When a generator turns on and off, it affects system conditions throughout the interconnected network. Large swings in load at one node affects system conditions at other nodes. A failure of a major piece of equipment in one part of the network can disrupt the stability of the entire system if resources are not available to the network operator to respond quickly to these contingencies. Moreover, efficient and effective remedial responses to equipment failures can involve coordinated reactions of multiple generators located remotely from the site of the failure. These attributes create potential network externality and "commons" problems.

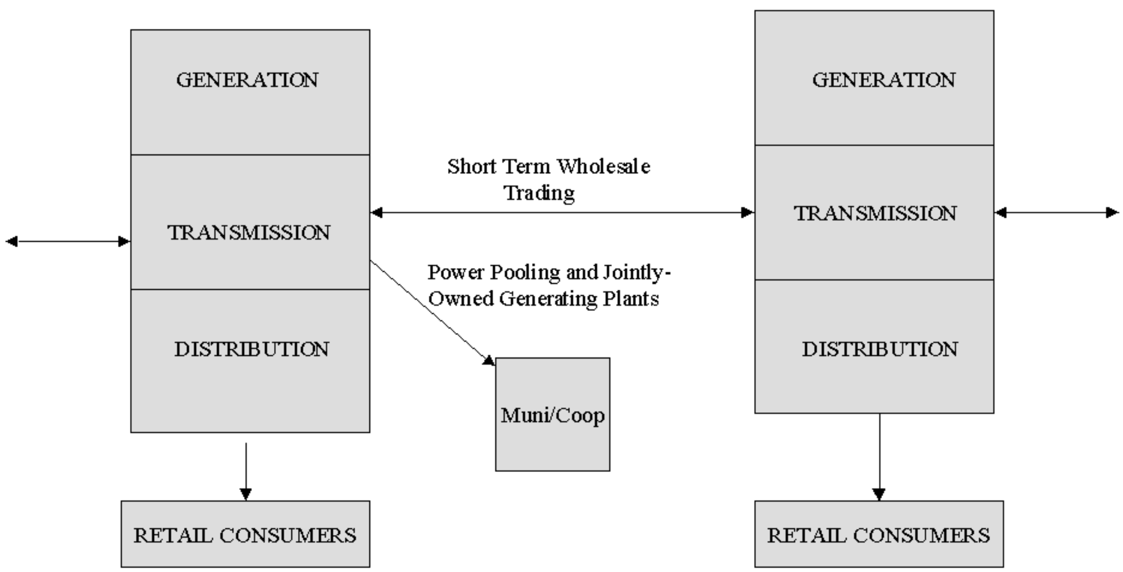
As we shall see in the discussion of the institutional arrangements governing the competitive electricity market in California, these attributes have important implications for market design, transmission network operating protocols, and market performance.

b. Industrial Organization: Market Structure and Regulation Circa 1980

The U.S. electric power sector evolved largely with firms that were (and in most regions of the country still are) vertically integrated into generation, transmission, distribution and retailing and held de facto exclusive rights to serve retail consumers within defined geographic areas. These firms were generally subject to "cost of service" or "rate of return" regulation by state public utility commissions. The economic rationale for vertical integration is discussed in more detail in Joskow (1996). Figure 1 provides a simple picture of the structure of the U.S. electric power industry around 1980.

FIGURE 1

TRADITIONAL INDUSTRY STRUCTURE



While virtually all electricity sectors on earth evolved with vertical integration between generation and transmission (and often integration with distribution as well), the organization of the U.S. electric power industry was atypical in a number of ways. The most striking differences are the large number of electric companies providing service to the public and the primary role of private rather than state-owned companies. The bulk of the resources in the U.S. sector have been accounted for by a relatively large number of privately-owned firms (Investor-Owned Utilities or IOUs) supplying retail electric service to residential, commercial, and industrial consumers in defined geographic areas that they have served with de facto exclusive franchises. While these electric power companies were typically vertically integrated into generation, transmission and distribution, there were over 100 of them and they varied widely in size. Thus, while the industry has been characterized by vertically integrated regulated monopolies as in most other countries, horizontal integration was not nearly as extensive.

In addition to the vertically integrated IOUs there are also thousands of (generally small) unintegrated or partially integrated public and cooperative distribution entities that buy power from IOUs as well as from state, cooperative and federal power production and marketing entities using the transmission networks of surrounding IOUs. There are also a few large municipal utilities that are vertically integrated and look much like a typical IOU (e.g. the Los Angeles Department of Water and Power). Collectively, these non-IOU entities still account for over 20% of the electricity generation and distribution in the U.S.

The decentralized industry structure that emerged in the U.S. is, in a sense, not ideally matched to the physical attributes of the electric power networks that have evolved over time. From a physical perspective, the U.S. sector (combined with portions of Canada and northern Mexico) is composed of three large synchronized AC networks: the Eastern Interconnection, the Western Interconnection, and the Texas Interconnection.[3] However, each of these three networks is not under the physical control of a single entity. Instead, there are over 140 separate "control areas" superimposed on the three networks where individual vertically integrated utilities or groups of utilities operating through power pooling arrangements, are responsible for generator dispatch, network operations, and maintaining reliability on specific portions of each of the three physical networks. The thousands of unintegrated or partially integrated municipal and cooperative distribution entities are typically embedded in one of these individual control areas and rely on the host control area operator to deliver power to them. Individual control areas operated by vertically integrated utilities or holding companies in the U.S. vary widely in size and none is as large as the networks governed by single network operators in England and Wales, France, Spain or Japan.

To harmonize and rationalize the dispersed ownership and control of generation and transmission facilities that are physically interconnected and whose operations have impacts on facilities in remote control areas, the U.S. industry has developed a complex set of standard operating protocols and bilateral and multilateral agreements designed to maintain reliability, to facilitate coordinated operations between interconnected transmission systems, to facilitate trades of power between control areas, and to minimize free riding problems, while maintaining dispersed ownership and control of vertically integrated "pieces" of the relevant networks. These operating protocols were developed through the National Electric Reliability Council (NERC), nine regional reliability councils, and a larger number of sub-regional reliability organizations. The successful operation of these protocols relied heavily on control areas operated by vertically integrated utilities which were encouraged to cooperate rather than to compete with one another.

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[3]There are small DC ties connecting the Western and Eastern systems as well.

The decentralized structure of the U.S. electricity sector fostered the early development of competitive *wholesale* markets through which utilities buy and sell electricity among one another to reduce the costs of supplying their franchise customers. Wholesale trade expanded rapidly in the 1970s, initially in response to large differences in the short run marginal cost of hydroelectric coal, oil, and natural gas generating units as well as to variations in demand and capacity availability among utilities in the same region. By the 1980s, a set of fairly active <u>wholesale</u> electricity markets had emerged in the U.S. (See Joskow and Schmalensee (1983)) and Joskow (1989) for a more detailed discussion of wholesale power markets). In all cases, these were "utility to utility" wholesale transactions. Virtually all retail consumers received a “bundled” product (generation, transmission, distribution and retailing services together) from the local monopoly distributor (whether vertically integrated or not) with prices based on the average total cost of both generation produced by the plants owned by the distribution utility plus power purchased under contract from third parties.

<u>c. Regulation</u>

IOUs are regulated by both state and federal regulatory agencies. Each state has a state public utility commission that defines service obligations, determines prices, and approves major investments in generation, transmission, and distribution facilities (see Joskow and Schmalensee (1986)). Regulated prices were traditionally determined pursuant to accounting cost of service ratemaking principles whereby a utility's base prices are set to reflect its "reasonable" operating costs, depreciation of capital equipment, taxes, and a "fair rate of return" on the depreciated original cost of its "prudent" capital investments or rate base. These prices were not reset continuously with changing demand and cost conditions and the associated "regulatory lag" provided some efficiency incentives compared to a pure cost-plus system (Joskow and Schmalensee 1986). Moreover, because of the poor incentive properties of cost-based price regulation, regulatory agencies employing this type of regulatory mechanism spent considerable resources monitoring, necessarily imperfectly, regulated firm investment and operating costs in order to exclude costs from being included in regulated prices that were not deemed to be "prudent."

Under the Federal Power Act of 1935, the Federal Energy Regulatory Commission (FERC) shares regulatory responsibilities with the states. However, its price regulatory authority is limited to the regulation of "wholesale power" transactions and interstate transmission service provided by transmission-owning utilities to third parties. Wholesale power transactions are defined as sales of energy produced by a generating company to a distribution company or marketing intermediary (which may or may not also be in the generation business). That is, they are inter-utility transactions. FERC has neither jurisdiction over power sales to retail consumers nor jurisdiction over internal transfers of energy from generating plants to transmission and distribution facilities and then on to retail customers within a single vertically integrated utility operating company. These internal transfers are state jurisdictional.

FERC jurisdictional "unbundled" interstate transmission service has typically been used to support wholesale power transactions or to allow a distribution utility to gain access to generation service from a generating plant in which it has an ownership interest, but to which it owns no direct physical transmission interconnection. FERC jurisdictional interstate transmission service would also typically be required to consummate direct sales of generation service from generators to retail customers using the transmission and distribution networks to which both the suppliers and customers have access as is now being contemplated in a growing number of states (more on this presently).

Accordingly, for the typical vertically integrated IOU, the vast bulk of its costs have historically been subject to state, rather than federal, regulation because generation and transmission services were transferred internally within the company, rather than through market transactions, and are combined with the company's distribution system and associated costs to provide a "bundled" service (G+T+D) to retail consumers. Thus, under the industry and regulatory structure that evolved during the 20th century in the U.S., it has been the states rather than the federal government that have had the primary regulatory authority over electricity investments, operating costs, and retail prices paid by end-use consumers.

PERFORMANCE OF TRADITIONAL INDUSTRY AND REGULATORY INSTITUTIONS

It is only natural to hypothesize that a long historical record of poor economic performance of the electricity sector would be a primary motivation for major structural and regulatory reforms. After all, the institution of regulated monopoly has a bad reputation. Cost-plus regulation dulls incentives[4] and government granted monopolies induce rent seeking and lead to taxation by regulation. However, the electric power sector in the U.S. has performed

[4] Of course, electric utility regulation was never pure cost plus regulation. Both regulatory lag and opportunities for regulators to monitor and disallow costs ensured that there were some incentives to control costs. Joskow and Schmalensee (1986).

fairly well over time based on a variety of "macro" performance criteria. In particular, it has supplied electricity with high levels of reliability, investment in new capacity has been readily financed to keep up with (or often exceed) demand growth, system losses (both physical and those due to theft of service) are as low or lower than those in other developed countries, and electricity is available virtually universally. This contrasts sharply with the performance of the electricity sectors in many other countries, especially developing countries and many developed countries which relied on state-owned utilities.

On the retail price front, average real electricity prices fell rapidly from the early 1900s until the early 1970s. Indeed, during this time period, the U.S. electric power sector had one of the highest rates of productivity growth of any major industry in the U.S. economy. However, real prices for electricity increased sharply from the mid-1970s until the mid-1980s, in response to increases in basic energy prices, high interest rates, tightened environmental standards, and investments in capital-intensive nuclear power plants. Both scale economies and thermal efficiency improvements in generating technology appear to have been exhausted by about 1970 (Joskow, Joskow and Rose, Rose and Joskow). Nevertheless, average real electricity prices began to fall in the mid-1980s, and continued to fall during the 1990s; though electricity costs and prices in some areas of the country remained well above their historical low values during this recent time period. The average price of electricity in the U.S. in 1997, prior to major reforms, was 6.8 cents/kWh. The average price charged to residential customers was about 8.4 cents/Kwh and the price to industrial customers was about 4.5 cents/kWh. (The difference between the residential and industrial prices largely reflects differences in load factor and the voltage level at which electricity is supplied.) These prices were and are at the low end of the range of prices for OECD countries. Nevertheless, as I will discuss presently, the *average* price data hide large inter-state and inter-regional differences in electricity prices.

Despite these generally favorable performance attributes, there are a variety of apparent short run, medium run, and long run inefficiencies that are targets of opportunity for structural and regulatory reforms. Ultimately, the success of these reforms should be judged based on the extent to which they remedy these performance problems. At the very least, we should expect a reform program to yield superior economic performance to the system of regulated monopolies that it is replacing.

In the short run, the traditional system did a good job efficiently and reliably dispatching generating plants, making cost-reducing short-term energy trades between generating utilities, maintaining network reliability, dealing with congestion, unplanned outages and system emergencies. Restructuring for competition and regulatory reform is unlikely to lead to significant short run cost savings by improving the efficiency with which generators are scheduled and dispatched. Indeed, I have argued that decentralization and (imperfect) competition are likely to lead to poorer performance in some of these short run dimensions as a result of the difficulties of creating efficient decentralized market mechanisms to replace short run dispatch and coordination decisions made within vertically integrated firms coordinating their operations subject to NERC operating protocols. The difficulties arise both from increased transactions costs and from short run market power problems, or more generally imperfect competition, associated with decentralized wholesale power markets and supporting transmission institutions. Decentralization will require more robust transmission networks and new transmission network governance arrangements to control short run dispatch inefficiencies and to maintain network reliability. More on this presently.

Decentralized competitive wholesale markets for electricity are most likely to have significant beneficial effects in the medium and long term in the following areas:

1. *Generation Investment Decisions and Construction Costs*: On average, roughly half of the cost of a Kwh of electricity is associated with the operating costs and carrying charges associated with electric generating facilities. There is substantial variation across utilities (within and between countries) in the construction costs of similar generating units (Joskow and Rose (1985), Lester and McCabe (1993), Monopolies and Mergers Commission (1981, p. 256)) which cannot be readily explained by differences in underlying cost opportunities. Some of these variations may be explained by poor cost control incentives created by price regulation and/or public ownership in a monopoly environment. More generally, with vertically integrated monopolies, as in the U.S. before the 1980s, there was no mechanism through which companies that were particularly good at managing the construction of generating plants could expand their market. Nor was it easy for those generating utilities that did not manage generation construction projects very well to be penalized severely or driven out of the business. Aside from joint ventures, each utility managed its own generation construction projects. Smaller utilities with less experience may have been less capable of managing more complex technologies than larger utilities and were also less innovative (Rose and Joskow (1985)). It is also often argued that the old "Averch-Johnson" effect gave utilities incentives to choose more capital intensive generating technologies (e.g. nuclear instead of coal) than was economical. I don't think that there is much empirical support for this proposition given <u>ex ante</u> projections of the construction costs of

nuclear plants and future fossil fuel prices. There *are* good reasons to believe, however, that some utilities managed the actual construction of these projects poorly. More importantly, for a variety of reasons, the large investments in nuclear generating technology made by U.S. utilities during the 1970s and 1980s turned out, ex post, to be uneconomical compared to generation supply alternatives. Whether these investments were bad decision ex ante or simply bad outcomes ex post, the result is that many utilities are saddled with power plants whose accounting costs (used for regulatory purposes) are far above their competitive market values.

2. *Politicized Resource Planning Processes*: In some regions of the U.S., in particular the Northeast and California, the process through which utility investment and power contracting decisions were made became highly politicized in the late 1980s (Joskow (1989)). Utilities came under pressure to invest in or contract for power supplies from cogenerators and renewable energy sources at prices that were far in excess of the least cost alternatives available. These projects came into operation during the late 1980s and early 1990s and caused electricity costs and prices to rise significantly in the affected states. One of the potential benefits of creating competitive decentralized markets for wholesale power is to bring these politicized resource planning processes to an end and to create an environment that stimulates the lowest cost generation sources, consistent with environmental regulations, to enter the system.

3. *Operating Costs of Generating Units*: The restructuring of the Central Electricity Generating Board (CEGB) and the creation of competitive wholesale and retail markets in England and Wales was driven in part by a desire to break the back of the coal miners' union and to make it possible for the electricity suppliers to turn to lower priced coal sources both domestic and foreign. Prior to restructuring, the CEGB bought a lot of high-priced domestic coal and supported the domestic coal industry. The theory was that the combination of privatization and competition would place significant constraints on the coal industry and give the generators the flexibility to buy the cheapest fuels available. Forced purchases of high-cost coal has not been a significant problem in the U.S. However, the operating costs of generating plants depend on more than the price of fuel. The costs of operating generating units also depend on the availability of the unit (i.e. the fraction of the year that it is not being fixed and is available to supply electricity) and their thermal efficiency. There is very substantial variation in both availability and thermal efficiency across fossil and nuclear generating units, after controlling for the underlying attributes of the technology that was chosen

(Joskow and Schmalansee (1987)), Lester and McCabe (1993)). Moreover, some utilities appear to be systematically better operators than others. The regulatory process penalized and rewarded operating performance only indirectly, although a number of states began to focus on performance based incentives for performance during the 1980s (Joskow and Schmalensee (1986)). Again, the market mechanisms for driving firms to best practice maintenance and operating protocols were blunted by the institution of regulated monopoly.

4. *Retirement of Uneconomical Generating Plants*: Under the old regime in England and Wales ancient inefficient generators were kept running to create a market for expensive coal and to maintain employment. Since the reforms were introduced in England and Wales in 1990, a large number of generating plants have closed and have been replaced with less costly, efficient, and more environmentally friendly gas-fired combined-cycle generating facilities. Should we expect similar responses in the U.S.? Some have argued that U.S. utilities have continued to operate some nuclear plants and old fossil plants even though it would have been economical to close them and that in the U.S. too, competition will lead inefficient generating plants to close and will accelerate investments in more efficient (and environmentally friendly) generating technologies. In the U.S., regulatory rules treat the remaining capital costs of "abandoned plant" in a way that is less rewarding to shareholders than continuing operations, as long as the regulators do not catch them operating the plant inefficiently and do not assess an even more costly penalty for failing to close an inefficient plant. Forcing these plants to succeed or fail based on the revenues they can earn in the market may lead some plants to close earlier than would have been the case under traditional regulatory arrangements.

5. *Employment Practices and Wages*: The experience with restructuring, privatization, and deregulation around the world suggests that public enterprises and private firms subject to price and entry regulation employ too many workers (have low levels of labor productivity). The number of workers that have been shed by the electricity sector in England and Wales since 1990 is quite impressive indeed. However, the pre-restructuring CEGB and Area Boards in England and Wales had much lower levels of labor productivity than U.S. utilities (over 50% lower) and the electricity sector in England and Wales may have been unusually inefficient compared to the U.S. and other developed countries. Nevertheless, the recent efforts by U.S. utilities to reduce costs, in part, by reducing employment levels, suggests that there are significant

opportunities for increasing labor productivity here as well. On the compensation side, the experience with some other regulated industries is that wages fell after deregulation in the face of more competition, especially from non-unionized suppliers (Joskow and Rose (1989)). There is limited evidence that wages for production workers in the regulated sector are higher than in other sectors, controlling for various indicators of human capital (Katz and Summers). On the other hand, senior management of regulated private utilities and public enterprises are paid significantly less than managers with similar (measurable) attributes would earn in unregulated businesses of similar size (Joskow, Rose, and Shepard (1993)). The potential gains from improvements in labor productivity and wage concessions must be kept in perspective, however. In the U.S., wages and benefits account for only about 12% of the total cost of supplying electricity.

6. *Pricing Inefficiencies*: There are wide variations in the care that has been taken by utilities and regulators to establish electricity price structures that provide the best price signals and associated consumption incentives to consumers, given the relevant marginal supply costs and the budget constraints that these entities operate under. Electricité de France (EDF) offers the most sophisticated retail tariff structures in the world to large industrial customers. The record among U.S. utilities is less impressive. Perhaps more importantly, the average cost-based regulatory system in the U.S. had a built in predisposition to lead to prices that are poorly aligned with the relevant marginal costs. Specifically, tariffs are designed to recover the operating and fixed costs of the supplier, based on historical investment decisions and their associated costs. As a result, when there is excess capacity, prices tend to rise and when capacity is short, prices tend to fall, just the opposite of how a market would work. This type of "average cost" bias may be inherent in any practical regulatory scheme that satisfies traditional rent extraction, production cost efficiency, investment viability, and credible regulatory commitment constraints (Gilbert and Newbery (1994)). It was not a significant problem prior to the 1970s, however, because of high and steady demand growth, stable fuel prices, and steady technological progress. The turbulent economic circumstances of the 1970s and 1980s, however, meshed poorly with traditional cost-based regulatory institutions (Joskow (1989)). The development of public spot and futures markets for electricity will produce transparent information on short-term price fluctuations and expected forward price levels at various locations on the network. One of the potential efficiency benefits of competitive wholesale markets combined with

retail competition is that retailers will install real time meters at customer locations and work with consumers to adjust consumption behavior to reflect changing electricity prices in the wholesale market.

7. *Stimulating Innovation*: Unlike the U.S. telephone industry, electric utilities in the U.S. and other countries generally are not vertically integrated into the manufacture of electric appliances or power supply equipment. This equipment is manufactured by companies like GE, Westinghouse, Toshiba, ABB, etc. Customers are free to choose their own appliances and equipment for using electricity. If there is a regulatory problem slowing down innovation associated with the appliances and equipment purchased from competing suppliers by retail consumers of electricity, it would be traced to the absence of retail meters and tariffs that track rapid movements in wholesale prices. Equipment manufacturers will not develop new energy using equipment that can exploit opportunities for energy conservation in response to price volatility if potential consumers of that electricity do not see these price signals. If regulation has retarded the development and deployment of innovative electricity *production* technologies, the fault would lie with the procurement behavior of vertically integrated utilities. There is some systematic variation in the rate at which utilities adopt new generating technologies (Rose and Joskow). Moreover, the growth of a competitive independent power (IPP) sector in the U.S., which I will discuss further in the next section, clearly stimulated innovation and speeded up diffusion of more efficient generating technologies. Absent the demand for these technologies by cost-conscious IPP developers, it is likely that their development and diffusion would have been significantly slower under the old regulated monopoly regime.

How much do all of these potential inefficiencies add up to and how well will the reforms being implemented succeed in ameliorating them? Nobody knows with any degree of precision, though if the results from other sectors are a guide, the gains could be larger than is apparent today. The bulk of electric utility costs are fixed in the short run (depreciation, interest payments, taxes, deferred cost items, long term fuel and purchased power contracts, etc.). Wages and benefits account for about 10% of total costs and fuel another 20%. The system has done a good job efficiently dispatching generating plants, managing congestion, and maintaining reliability. This is why I would argue that there are relatively small <u>short run</u> benefits from promoting competition in generation but potentially significant <u>long run</u> benefits from doing so. The benefits associated with lower construction and operating costs overall in the supply of generation over time, improved incentives to close inefficient plants, better investment decisions, improved retail price signals, etc., are potentially large and can more than offset some additional imperfections in generator dispatch, network coordination and constraint management that may accompany horizontal and vertical decentralization. This happy outcome depends on designing sound transmission network, competitive wholesale power market, and retail market institutions and mitigating serious market power problems efficiently where they arise in power or transmission markets. I will discuss these issues in more detail below in the context of the implementation challenges that have been confronted in practice in the last few years.

It is sometimes argued that one of the primary forces spurring restructuring and competition in electricity is that the *generation* of electricity is no longer a natural monopoly as a consequence of technological change. Generation per se has never really been a strong natural monopoly (Joskow and Schmalensee 1983) and I do not believe that the demise of natural monopoly characteristics at the generation level is the driving force behind the changes taking place in the electricity sectors around the world. Just look at the U.S., with hundreds of utilities owning and operating generating plants with little evidence that huge generating companies are necessary to exploit available economies of scale in generation *per se*. Cheap natural gas and aero-derivative Combined-Cycle Generating Technology (CCGT) have certainly significantly reduced the minimum efficient scale of new generating facilities, and reduced planning and construction lead times, and facilitated siting as well. These developments have increased the *feasibility* of creating competitive generation markets quickly, but did not fundamentally transform a sector with natural monopoly characteristics to one in which these characteristics are completely absent.

The natural monopoly rationale for vertical and horizontal integration in electricity does not and has not relied primarily on the attributes of the costs of building and operating individual generating plants *per se*. Rather, it is the attributes of the transmission network and it's ability to aggregate and facilitate the operation of generating facilities dispersed over wide geographic areas to achieve cost efficiency and reliability objectives over time frames from seconds to decades, that has played the most important role in defining the vertical and horizontal structure of this industry. It is these complementarities between generation and transmission networks that are the primary source of scale and scope economies in electricity. They are the reasons why the industry evolved with a vertically integrated structure combined with either horizontal integration to include generators spanning an entire national network in a single firm (as in France and England prior to 1990) or a complex set of cooperative arrangements linking individual control areas that are part of the same synchronized AC system as in the U.S., Japan and Spain.

These vertical and horizontal hierarchies solved real technical and economic coordination problems, but they largely replaced competition with public or regulated private monopolies. The key technical challenge in relying on decentralized competition at the generation level is to do so in a way that preserves the operating and investment efficiencies that are associated with vertical and horizontal integration while mitigating the significant costs that the institution of regulated monopoly has created. Improvements in network control technologies, communications and computing speed are important for responding to this challenge, but so too are fundamental changes in the institutional arrangements that govern the electric power sectors, a subject to which I now turn.

INITIAL EFFORTS TO INTRODUCE OPPORTUNITIES FOR COMPETITIVE ENTRY INTO WHOLESALE GENERATION SUPPLY

a. Public Utility Regulatory Policy Act of 1978

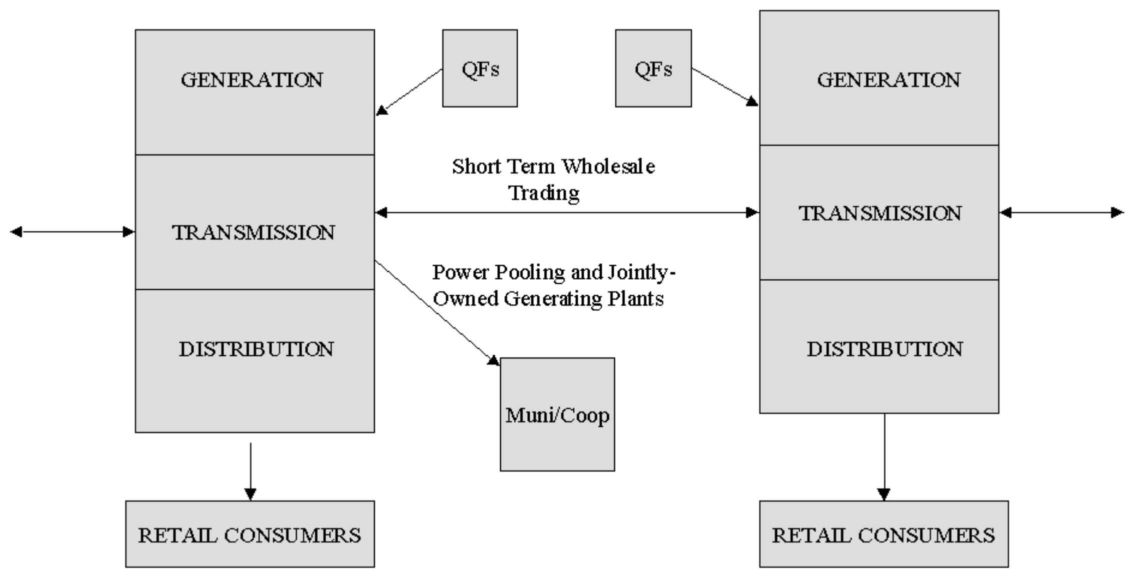
Title II of the Public Utility Regulatory Policy Act (1978), or PURPA, played an important role in stimulating the entry of independent power producers into the electric power sector during the 1980s and helped to set the stage for the more dramatic reforms of the late 1990s. Prior to PURPA there were effectively no unintegrated independent generating companies in the U.S. The bulk of the generation was either owned by vertically integrated utilities or fully contracted under long term accounting cost-based contracts to distribution utilities. The primary motivation for PURPA was to encourage improvements in energy efficiency through expanded use of cogeneration technology and to create a market for electricity produced from renewable fuels and fuel wastes. It was not motivated by a desire to fundamentally restructure the electricity sector and to create an independent competitive generation sector. However, it turned out to have effects significantly different from what was intended when it was passed. PURPA was largely responsible for creating an independent generation sector and the supporting market and regulatory institutions to create a competitive market for new generating resources.

PURPA required utilities to purchase power produced by certain Qualifying Facilities (QFs), primarily cogenerators and small power plants using renewable fuels. Figure 2 provides a picture of the electric utility industry around 1985 after QFs began to enter the system. Subsequent FERC regulations required utilities to pay QFs a price no less than the utility's "avoided costs" (Joskow 1989), though it left implementation of these regulations to each of the states. Several states, including California, New York, Massachusetts, Maine, and New Jersey embraced PURPA with gusto and enacted regulations that exceeded their minimum obligations under PURPA in an effort to stimulate QF supplies to utilities in these states. They required utilities in these states to sign long term contracts (20 to 30 years) with QFs at what turned out to be extremely high prices. Utilities with purchase contracts with QFs bundled these supplies with those from their own generating facilities and effectively resold the electricity produced from these facilities as part of the bundled service provided to retail customers. The costs of these contracts in turn were reflected in regulated retail prices as a cost pass-through. Moreover, PURPA provided exemptions to the Public Utility Holding Company Act (PUHCA) to QF owners. This made it possible for a large number of non-utility companies to enter the electric generation business as owners of QFs.[5] Roughly 60,000 Mw of QF capacity came into the sector during the 1980s and early 1990s and eventually accounted for 10% of total U.S. generating supplies. This capacity was concentrated in New England, New York, New Jersey, Pennsylvania, California and Texas.

[5]Utilities and public utility holding companies were allowed to own no more than a 50% interest in a QF. However, some of the most successful QF development and operating companies are subsidiaries of utility holding companies (an exempt holding company could retain its single state exemption and still have interests in QFs located anywhere in the U.S.).

FIGURE 2

TRADITIONAL INDUSTRY STRUCTURE +PURPA



There are four important legacies of PURPA that have had important effects on more recent reforms. First, the Act changed prevailing views about vertical integration between generation service and transmission and distribution services. In particular, it became clear that non-utilities could build and operate generating facilities cost effectively. Second, the long term contracts that utilities were compelled to sign with QFs in a number of states had pricing provisions that turned out to require payments that far exceeded the competitive market value of electricity supplied by the QFs under contract. Third, as I have already noted, the growth of a competitive QF/IPP market in the U.S., which I will discuss further in the next section, clearly stimulated innovation and speeded up diffusion of gas CCGT technology. Absent the demand for these technologies by cost-conscious QF/IPP developers, it is likely that their development and diffusion would have been significantly slower under the old regulated monopoly regime. Fourth, it created an interest group --- independent power producers --- that desired to find ways to develop more power projects in states that had not enacted regulations favorable to QFs, to shed PURPA's restrictions on technology, size and fuel use, to have an opportunity to compete more directly against existing generating plants owned by IOUs, and to amend PUHCA's onerous restrictions on who could own independent power projects (IPPs) which did not meet PURPA's thermal efficiency, fuel, and size restrictions.

b. Expanding Competitive Opportunities for IPPs

The development of competitive wholesale generation markets in which non-QF IPPs could at least compete to supply incremental utility capacity requirements faced a number of regulatory barriers. First, unlike QFs covered by PURPA, sales by IPPs or by utilities with excess capacity were subject to FERC regulation under the Federal Power Act. FERC required prices, especially for sales from a specific facility, to be "cost justified." This in turn meant that the prices charged would have to adhere to traditional cost of service/rate of return principles. These ratemaking principles were consistent with regulating a utility serving a legal monopoly franchise and subject to a prudent investment standard. However, they were not compatible with the kind of take and pay incentive contracts upon which QFs increasingly relied or on speculative market entry by "merchant" IPPs without prearranged long term contracts.

In 1988, FERC began to reconsider its pricing regulations in an effort to encourage entry of non-QF IPPs into the electricity sector, as well as to encourage utilities with excess capacity to sell it to third parties under long term contracts.[6] FERC's market-based pricing regulations evolved to support sales by independent power producers (as well as unregulated utility-affiliates making power sales remote from their affiliated regulated utility retail service territory) at market-based prices if they could satisfy FERC's horizontal and vertical market power criteria. FERC also accommodated the entry of power brokers that sought to enter the market to arrange power transactions between one or more sellers of power and specific purchasing utilities.

By 1991, FERC had been largely successful in removing federal price regulation barriers to the entry of independent power producers that were not QFs under PURPA. In this way, it created opportunities for utility buyers to seek competitive bids from such entities and for these entities to build facilities to supply power to willing buyers. However, FERC had absolutely no authority to force utilities to purchase electricity from non-QF independent power

[6]In 1988 FERC issued three then controversial Notices of Proposed Rulemaking (NOPRs) that dealt with wholesale power and transmission service pricing as well as the regulatory treatment of independent power producers. FERC never issued final rules following the comments and controversy over these NOPRs. However, it subsequently proceeded de facto to implement many of the policies contained in the NOPRs through case by case rulings on filings presented to the Commission.

suppliers or from other utilities with excess capacity. Unlike QFs under PURPA, there was no federal requirement to purchase from these entities. For most utilities, generation resource procurement regulations governing what a utility built or contracted for were subject to state rather than federal jurisdiction. And the enthusiasm of the states for encouraging utilities to rely on competitive procurement arrangements to choose the lowest cost generation services supplier regardless of ownership arrangements varied widely. States like New York, Massachusetts, California, and New Jersey encouraged utilities to take an "all source" competitive procurement perspective and not to rely only on new generating capacity that they would own subject to cost-based regulation. However, many other states were much more cautious about moving further away from the traditional vertical integration and cost-based regulation model.

Restrictions on the availability of transmission and related network services owned and controlled by vertically integrated utilities also slowed the development of fully competitive wholesale markets for power. For a utility buyer and a generation seller to consummate a transaction, transmission service, interconnection, control, congestion management, and dispatching services had to be provided. This was not a serious problem when the supplier was a QF or IPP located in the buyer's (vertically integrated utility) control area as long as the buyer was interested in consummating the purchase. However, a supplier of generation services required transmission and related network services from other utilities if its generating plant was located outside the purchasing utility's control area. Under the Federal Power Act of 1935, though, FERC could not order a utility to provide interstate transmission services or related network services or to build facilities to support such transactions. FERC could only regulate the prices at which transmission service could be sold. Thus, while FERC could regulate the prices charged for transmission service, and in this way control monopoly pricing for transmission, there was concern that "intervening" utilities would deny service or limit the services available to competing suppliers of generation service so that they could protect their markets for wholesale power supplied by their own generation facilities. The potential problems here were compounded by the balkanization of the interconnected networks with pieces owned and operated by many different utilities in most regions, since an economical transaction could involve a “contract transmission path” requiring “wheeling” across the transmission systems owned by several utilities. In this case, transmission service could be difficult to arrange as transmission charges for use of each “end-to-end” transmission system were “pancaked” on top of each other.[7]

By 1991 it was clear that FERC wanted to promote "open access" to utilities’ transmission systems to all third party wholesale buyers and sellers based on non-discriminatory terms and conditions. Absent statutory authority to require utilities to provide non-discriminatory transmission service, FERC began to use a carrot and stick (also sometimes referred to as “regulatory extortion”) approach to encourage utilities "voluntarily" to file open access transmission tariffs. In particular, FERC started to condition its approval of mergers between vertically integrated utilities and applications for “market based pricing authority” for sales to neighboring utilities on their filing of open access transmission tariffs.[8] However, the opportunities for FERC to apply this kind of leverage were limited. Utility mergers were few and far between in those days, and many utilities could easily “cost justify” what were effectively market-based sales of wholesale power since the average total accounting costs of the existing stock of generating plants that they could rely on for regulatory purposes were often far above the competitive market value of the electricity they were selling (more on this below).

c. The Energy Policy Act of 1992 (EPAct92)

By 1991, the forces unleashed by PURPA and FERC's initiatives on market based pricing and independent power producers[9] had led those interested in exploiting the associated competitive market opportunities to seek relief from the statutory restrictions on the entry of IPPs through amendments to the Federal Power Act (FPA) and PUHCA. PUHCA regulation

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[7] Traditional regulated transmission prices had the following peculiar feature. The price for wheeling electricity 200 miles from point A to point B over a single utility’s transmission system would be about 50% of the cost of the same transmission transaction if it happened to require crossing two transmission systems, even if the distance and characteristics of the underlying facilities were the same.

[8] For example, the merger of Pacific Power and Light and Utah Power and Light (1989) and merger involving Northeast Utilities and Public Service Company of New Hampshire (1991). The argument was that the mergers created or enhanced market power in one or more markets and that by offering to provide "open access" transmission service to third parties mitigated such market power. In some cases FERC was willing to waive a hearing on market power issues if the parties have an approved open access transmission tariff in place. For example, the merger of Entergy and Gulf States Utilities (1993) and the merger of Public Service of Indiana (PSI) and Cincinnati Gas and Electric (1994).

[9] FERC had also issued regulations that reduced the administrative burdens placed on true independent power producers.

effectively precluded non-utilities from entering the generation business, restricted the ability of IOUs to do so outside of their regions, and effectively barred foreign acquisitions by U.S. utilities. The initial stimulus for statutory reforms came from IOUs and non-utilities which were interested in getting into the (non-QF) IPP business in the U.S. and abroad. In order to do so, they required changes to PUHCA to permit them to enter the IPP business outside of their utility service areas and to make foreign acquisitions through a holding company structure feasible. Basically, these interest groups sought an exemption from PUHCA's regulatory requirements that would otherwise have been triggered merely as a consequence of ownership of an IPP-type generating facility.[10] They also sought repeal of PUHCA's restrictions on ownership of foreign utility assets.

The proposals for these limited reforms to PUHCA prompted other interest groups to propose broader reforms in both the FPA and PUHCA. Of particular importance were the efforts by independent power producers, municipal utilities, and industrial customers to obtain changes in the Federal Power Act that would expand FERC's authority to order transmission owners to provide transmission service upon request by a wholesale or retail customer. Independent power interests, in particular, argued that they could not compete fairly with utilities in the wholesale market without access to transmission facilities made available based on reasonable and non-discriminatory terms and conditions. Thus, the removal of regulatory barriers to ownership of IPPs and the increased availability of transmission service soon became linked as important components of a federal policy to expand competitive *wholesale* market opportunities. While some large industrial groups sought federal legislation to give retail customers access to utility distribution and transmission systems at cost-based rates so that they too could shop for power in wholesale markets, these initiatives were opposed by utilities, state regulators, and environmental groups.

When the Energy Policy Act of 1992 was finally passed by the Congress in October 1992[11] it included provisions that removed PUHCA's barriers to utilities and non-utilities having ownership interests in independent power producers, removed PUHCA's restrictions on U.S. utilities owning electric utility assets in other countries, and expanded FERC's authority to order utilities to provide transmission (or "wheeling") service to support wholesale power

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[10]Existing registered holding companies also wanted changes in the Act that would allow them to develop IPP in areas outside of the regions where they presently operated and associated system integration requirements.

[11]P.L. 102-486, Title VII, October 24, 1992.

transactions. EPAct92 created a new class of electricity generators called "Exempt Wholesale Generators" (EWG), whose owners and operators are exempt from those provisions of PUHCA which had represented significant barriers to utility and non-utility entry into the IPP business. An EWG is defined as an entity engaged directly or indirectly through one or more affiliates in the business of owning or operating facilities dedicated exclusively to producing electricity for sale in wholesale markets .[12]

EPAct92 also amended the Federal Power Act to expand FERC's authority to order utilities to provide transmission (wheeling) service for wholesale power transactions.[13] Buyers and sellers of wholesale power were then free to petition FERC to order transmitting utilities to provide wheeling service, even if meeting such requests required the transmitting utility to expand its facilities. FERC in turn was directed to establish pricing regulations that promote the efficient generation and transmission of electricity and that allow utilities to recover the full economic cost of the transmission service provided. In response to utility concerns about retail wheeling, EPAct92 includes a specific provision that limits FERC's authority to order wheeling to support *wholesale* power transactions only, thus making it clear that FERC has no authority to order a utility to make unbundled transmission service available to serve a retail customer. Figure 3 depicts the structure of the industry envisioned by the major proponents of the reforms embodied in EPAct92.

In light of more recent developments, it is interesting to note that EPAct92 was built around the traditional model of a regulated monopoly distribution company that has the exclusive right to serve retail customers within its franchise area. It contains no provisions requiring utilities to open up their retail markets to competitive suppliers. Nor does it even require utilities to buy from IPP/EWGs. It does give FERC the tools to support state initiatives that might promote competitive procurement of incremental generation supplies or more radical restructuring to support more direct competition against incumbent generators and for retail customers. However, when EPAct92 was passed, most utilities thought that the law would make only incremental changes in the basic structure of the industry and did not envision it’s supporting a more radical competitive model. They would soon be surprised.

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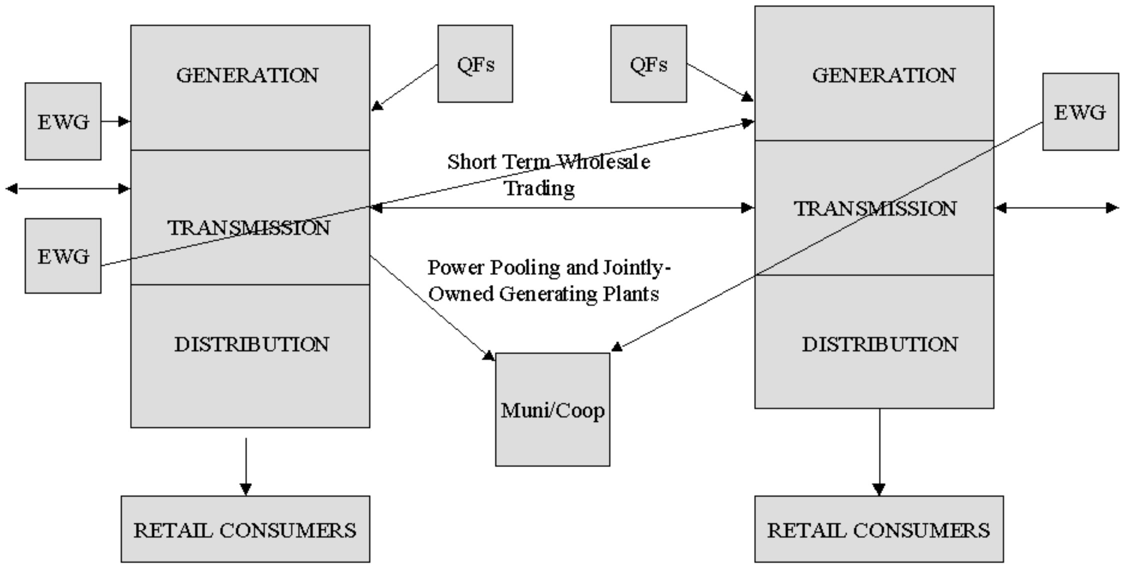
[12]P.L. 102-486, Section 711.

[13]P.L. 102-486, Section 721.

FIGURE 3

TRADITIONAL INDUSTRY STRUCTURE +PURPA+EPAct92



FERC INITIATIVES TO IMPLEMENT EPAct92's TRANSMISSION ACCESS PROVISIONS

After EPAct92 was passed, FERC embarked on a number of initiatives to expand transmission access opportunities for wholesale buyers and sellers of generation services. The initial focus was on creating more opportunities for IPPs to contract with utility buyers, even if they were located on another utility's transmission system; to increase opportunities for vertically integrated utilities with excess capacity to make wholesale sales to utilities with whom they were not directly interconnected; and to expand purchase opportunities for municipal distribution companies. These early initiatives included:

1. FERC required utilities to publish detailed information about the availability of transmission capacity on their systems and related operating characteristics of their bulk power facilities.[14]

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[14]Federal Energy Regulatory Commission, Proposed New Reporting Requirements Implementing Section 213(b) of the FPA, April 15, 1993.

2. FERC expanded the range of transmission services that utilities were required to offer in response to requests from wholesale buyers and sellers from simply point to point service to a full range of services that are "comparable" to the services that a vertically integrated utility provides to itself. FERC also required utilities to include comparable service provisions in "voluntary" transmission service filings even when these filings are not responses to wheeling orders by the Commission under Section 211 of the Federal Power Act. Precisely what "comparability of service" meant was unclear, however.[15]

3. FERC allowed wholesale customers to file for "generic" tariffed transmission service even in the absence of a specific buyer and a specific seller.

4. FERC made it clear that its approval of market-based pricing applications and merger applications by vertically integrated utilities would be contingent on their filing open access transmission tariffs with comparable service provisions. [16]

5. FERC encouraged the formation of regional transmission groups (RTG) to deal with transmission planning, operations, and pricing issues on a comprehensive regional basis.[17]

However, these early initiatives basically only required utilities to respond to transmission service requests on a case by case basis. Utilities were not required to file generic transmission tariffs that specified generally available transmission service offerings and associated maximum prices. Moreover, the nature of the transmission services that transmission owners were obligated to supply, and the associated prices, remained fairly vague, and utilities

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[15]NARUC Bulletin No. 22-94, May 30, 1994, page 6 (re AEP and Florida Power & Light Company).

[16]The Energy Daily, August 11, 1994, page 1 (re an application for market based pricing by Heartland Energy Services an affiliate of Wisconsin Power & Light Company, Docket Nos. ER94-108, ER94-475). Electric Utility Week, August 1, 1994, page 11 (re proposed merger between Central & South West and El Paso Electric, Draft Order in Dockets EC94-7 and ER-898).

[17]Federal Energy Regulatory Commission, Policy Statement Regarding Regional Transmission Groups, July 30, 1993.

defined the kinds of transmission services and the pricing principles applicable to them in a variety of different ways. Transmission service requests sometimes became lengthy negotiations. Some utilities responded to requests for transmission service by claiming that their transmission capacity was fully utilized to meet the needs of their regulated retail customers and their contractual obligations to sell power to municipal utilities and other IOUs.

FERC did apply the tried and true technique of "regulatory extortion" to get utilities to "volunteer" to do more when they needed something approved by FERC (e.g. a merger or market-based pricing authority for wholesale transactions). However, both FERC and transmission service customers became frustrated by the slow pace at which transmission service was being made available to support wholesale market transactions, and FERC continued to receive complaints about discriminatory terms and conditions (real or imagined) being offered for transmission service. Moreover, California's restructuring initiatives that began in April 1994 (more below) began to make it clear to FERC that its transmission access and pricing rules might have to support far more radical changes in the structure of the utility industry -- the functional separation of the generation of electricity from distribution service and the opening of retail electric service to competition -- and deal with a variety of new issues regarding state vs. federal jurisdiction over transmission, distribution, wholesale power sales and the treatment of "above market" costs of generating capacity and QF contracts (what came to be called the "stranded cost" problem).

a. <u>Orders 888 and 889</u>

In 1995 these considerations led FERC to initiate rulemakings on transmission service that ultimately served as the basis for two major sets of new rules issued by FERC in 1996. These rules are Order 888 -- "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs By Public Utilities and Transmitting Utilities,"[18] and Order 889 -- "Open Access Same-Time Information Systems."[19] These rules now serve as the primary federal foundation for providing transmission service, ancillary network support services, and information about the

[18] Final Rule issued April 24, 1999, 75 FERC ¶ 61,080.

[19] Final Rule issued April 24, 1999, 75 FERC ¶ 61,078.

availability of these services to support both wholesale and retail competition in the supply of generating services.[20]

Order 888 requires all transmission owners to file with FERC pro-forma open access transmission tariffs that transmission service customers can rely upon to define the terms and conditions of transmission services that will be made available to them. Order 888 specifies the types of transmission services that must be made available, the maximum cost-based prices that can be charged for these services, the definition of available transmission capacity and how it should be allocated when there is excess demand for it, the specification of ancillary services that transmission owners must provide and the associated prices, requirements for reforms to power pooling arrangements to comply with Order 888, and provisions for stranded cost recovery. All transmission owners and power pools have now filed open access transmission tariffs with FERC.

While Order 888 is very long, the basic principles it embodies are simple: transmission owners must provide access to third parties to use their transmission networks at cost-based maximum prices and non-discriminatory terms and conditions, make their best efforts to increase transmission capacity in response to requests by third parties willing to pay for the associated costs, and shall behave effectively as if they are not vertically integrated when they use their transmission systems to support wholesale market power transactions. Order 888 recognizes the sanctity of pre-existing commercial and contractual arrangements associated with the historical use of transmission systems and is generally sensitive to providing a smooth transition from the old regime to the new regime. It is not supposed to provide an opportunity for transmission owners unilaterally to terminate existing commercial relationships and associated obligations without fair compensation. FERC did not, at that time, make a concerted effort to resolve the problems created for transmission service customers by the large number of transmission owners, all operating under separate pro forma Order 888 tariffs, which existed in many regions of the country. So, for example to make a trade between Indiana and Pennsylvania, a trader might still have to deal with several transmission owners to get a complete “contract path” from the generator supplying the power to the customer. FERC recently addressed these issues in a rulemaking proceeding[21]

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[20] FERC Order 2000 regarding Regional Transmission Organizations issued in December 1999 is likely to become equally important. *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999).

[21] *Notice of Proposed Rulemaking Regarding Regional Transmission Organizations*, Federal Energy

and subsequently issued a set of regulations which strongly encourage the creation of large Regional Transmission Organizations (RTO) to resolve problems created by the balkanized control of transmission networks and alleged discriminatory practices of generators and energy traders seeking to use the transmission networks of vertically integrated firms under Order 888 rules.[22]

Order 889, issued at the same time as Order 888, requires each public utility or its agent (e.g. a power pool) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Same-time Information System (OASIS). This system must provide information, by electronic means, regarding available transmission capacity, prices, and other information that will enable transmission service customers to obtain open access non-discriminatory transmission service in a time frame necessary to make effective use of the transmission system to support power transactions. FERC went on in subsequent proceedings to define in more detail the precise information and formats that OASIS systems must have. OASIS systems are now operating in all regions of the country and rely extensively on internet technology to transfer information. Order 889 also required public utilities to implement standards of conduct to functionally separate transmission and unregulated wholesale power merchant functions to ensure that a vertically integrated transmission owner's wholesale market transactions are not advantaged by virtue of preferential access to information about the transmission network. Utilities must also make the same terms (e.g. service price discounts) available to third parties as they do to their wholesale power marketing affiliates.

Importantly, Order 888 established federal principles governing the recovery of stranded costs, -- which I will discuss in more detail presently. For utility-owned generating plants, stranded or "strandable" costs are defined conceptually as the difference between the net book value of a generating plant used for setting cost-based regulated prices and the market value of that plant if it were required to sell it's output in a competitive market. For a QF contract, stranded costs are generally defined as the difference between the present value of the contractual payment obligations and the present value of the competitive market value

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Regulatory Commission, issued May 13, 1999, 87 FERC ¶ 61,173.

[22] *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999). Order 2000 technically makes participation in an RTO voluntary, but there are carrots and sticks available to FERC that will create significant pressure for utilities to join RTOs. Order 2000 does not mandate a particular organizational form for an RTO, however.

of the electricity delivered under the contracts. Though these stranded cost recovery principles technically applied primarily to stranded costs associated with longer term wholesale power supply contracts between utilities, FERC extended their applicability to existing retail customers who became de facto wholesale customers (e.g. through municipalization or retail load aggregation) and indicated a willingness to consider providing backstop stranded cost recovery in the case of systems opened up to retail competition when state indicated that they did not have the authority to provide for stranded cost recovery. More importantly, FERC established the public policy case for allowing for stranded cost recovery in light of the long established regulatory rules in effect when the investments and contractual commitments were made and the public policy interest in facilitating restructuring and the creation of competitive wholesale power markets.[23]

Basically, FERC took the position that where utilities had made investments or contractual commitments to fulfill their wholesale and retail service obligations, in light of then prevailing regulatory and legal obligations and cost recovery principles, they should not be at risk for sunk costs or contractual commitments that could not be recovered in competitive markets created by virtue of new rules governing competition and retail franchise exclusivity. That is, FERC interpreted historical regulatory principles as a sort of "regulatory contract" (Joskow and Schmalensee 1986) that policymakers had an obligation to honor even in the absence of formal contract that provided for stranded cost recovery. There is some parallel here with FERC's earlier treatment of "above market" natural gas supply and interstate gas pipeline contracts in conjunction with its policies to open access to unbundled natural gas pipeline transportation capacity to support competitive purchasing of gas in the field by marketers and end-use customers only a few years earlier.

While FERC's position on stranded cost recovery was based primarily on its assessment of its legal obligations and equity considerations, it almost certainly reflected a set of more practical considerations. Specifically, a major impediment to incumbent utilities' accepting more fundamental changes in the competitive environment and cooperating in creating new transmission and wholesale market institutions necessary to support full wholesale and retail competition was their concern about stranded cost exposure. FERC, and ultimately most state commissions that have considered the stranded cost issue, effectively

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[23] Verifiable stranded costs net of all reasonable mitigation options.

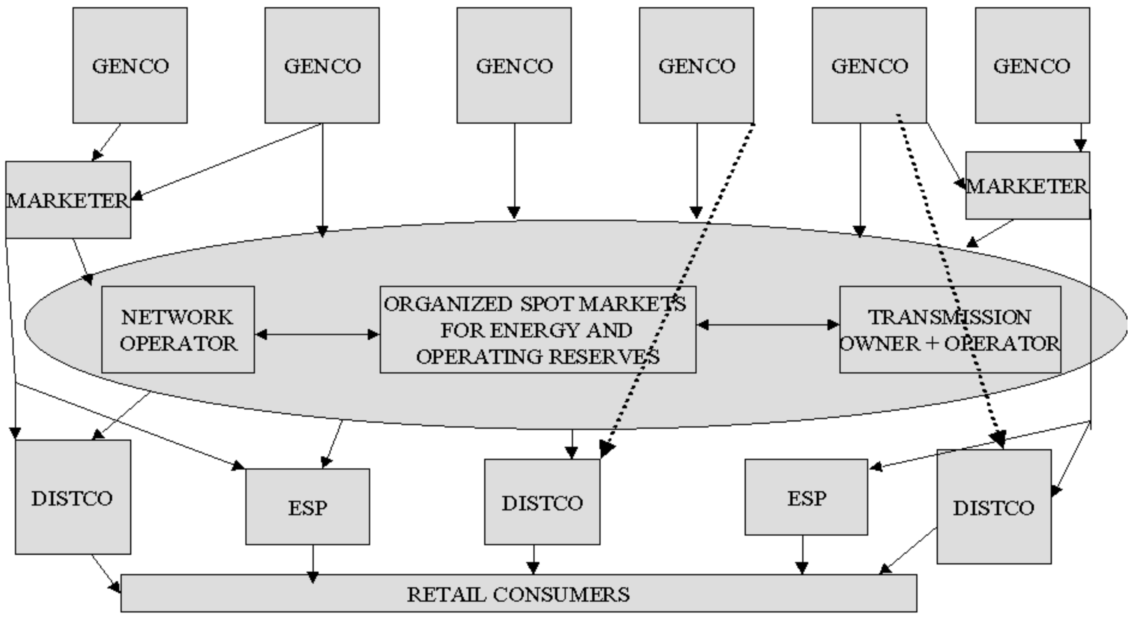
sent utilities with stranded cost problems the following message: "Play ball by opening up your transmission and distribution systems and by taking actions necessary to create competitive wholesale and retail markets quickly, and regulatory policy will treat requests for reasonable provisions for stranded cost recovery favorably. Moreover, this deal may not be on the table forever."

PRESSURES FOR MORE FUNDAMENTAL CHANGES

As I have already discussed, the evolution of competition in the U.S. electric power sector through 1992 occurred within a conceptual model in which utilities were expected to continue to have the exclusive right to serve retail customers within specific geographic areas at regulated "bundled" service prices. The provisions affecting electric utilities in EPAct92 (both those discussed above and numerous provisions affecting utility planning, energy conservation, and renewable energy) were based on this model as well. However, within two years of the passage of EPAct92, this basic "utility as exclusive retail service supplier" and "wholesale competition on the margin" models were under challenge as well. A variety of interest groups envisioned a new model with the following features: generation would be fully separated from transmission and distribution; regulated distribution and transmission charges would be "unbundled" from generation and retail service charges; wholesale generation service prices would be deregulated; generators would compete de novo in regional markets both to supply distribution companies purchasing on behalf of their retail customers (full wholesale competition with exclusive retail supply) and to supply retail customers as well ("retail wheeling") either directly or through financial intermediaries (wholesale marketers and retail Energy Service Providers (ESPs)). This model of the future structure of the electric power industry is depicted in Figure 4.

FIGURE 4

COMPETITIVE WHOLESALE + RETAIL MARKETS



This alternative full "wholesale competition" plus "retail unbundling and competition" model for the electric power industry was based on the same basic principles that governed the restructuring of the electricity sector in England and Wales in 1990 and the restructuring of the natural gas and telecommunications sectors in the U.S. Competitive services (e.g. generation) are to be separated from natural monopoly services (e.g. transmission and distribution), and the regulated monopoly services are to be made available and priced on an unbundled basis to retail consumers or their procurement agent. All generators compete in unregulated wholesale markets to serve retail demand. Retail customers or their agents are guaranteed non-discriminatory access to the monopoly transmission and distribution "delivery" services at regulated rates so that they can chose to shop directly in the wholesale market or through competing retail supply agents – Energy Service Providers (ESPs) --- who purchase electricity in wholesale markets and resell in to final consumers.

To understand the political and economic pressures that emerged for more radical changes in the electric power industry, it is useful to understand the components of regulated retail electricity prices.

Let:

$$P_R = C_T + C_D + C_G + C_R + DSM$$

Where:

P_R = Total regulated (bundled) price of retail service

C_T = Average total accounting cost of transmission service

C_D = Average total accounting cost of distribution (wires) service

C_G = Average total accounting cost of owned-generation and power contracts including QFs/IPPs

C_R = Average cost of customer services (e.g billing, customer care)

DSM = costs of various "public benefit" programs such as energy efficiency subsidies, renewable energy subsidies, and subsidies for low-income consumers

Table 1 (1A and 1B) displays the regulated price (P_R) for electricity for residential and industrial customers in a representative subset of the states for 1997 and 1998.[24] Let's focus initially on the 1997 prices, since they are similar to those prevailing in 1995 when the pressures for more radical reforms intensified. Of particular note are the large differences in prices across the states, with the states in the Northeast and California having much higher prices than the average for the rest of the country. Some of this price difference reflects inherent differences in the costs of providing electricity in different regions of the country,

[24] Industrial prices are typically much lower than residential prices because industrial customers take power at higher voltages and do not use the costly low-voltage distribution facilities that serve residences, have higher load factors (capacity utilization), and have lower thermal losses. Some of the difference may also result from some price discrimination reflecting the higher demand elasticities of some industrial customers, especially large customers that can self-supply electricity.

differences in population density, and differences in weather and electricity utilization patterns. However, a significant fraction of these price differences, especially as they relate to the generation component (C_G), reflects the costs associated with historical generation investment and contracting decisions, costs that had been included in prevailing regulated retail electricity prices. So, for example, today the competitive market price (P_{CG}) for electric generation service (averaged over a year) is in the range of 2.5 to 3.5 cents/kWh. However, in the mid-1990s, the regulated prices for generation service (C_G) in the highest priced areas of the country were in the 6.0 to 7.0 cents/kWh range. The difference between the regulated cost of generation service reflected in retail prices and the competitive market value of electricity (C_G – P_{CG}) represents a "generation service price gap" and a potentially "strandable cost" that utilities would have had to eat if they were required to sell their generation service at its market value rather than at it's regulated cost-based price.[25] The differences between the regulated costs and market values for generation service are largely, but not entirely, differences in sunk costs and long-term contractual commitments. (Let me note that there are also many utilities that have regulated prices *below* the competitive market value of electricity --- e.g. in places like Kentucky and Wyoming).

[25] How much they would have to eat would, of course, depend on the intensity of competition they faced if their wholesale and retail generation service prices were deregulated.

TABLE 1A
AVERAGE REVENUE PER KWH
RESIDENTIAL CONSUMERS[26]
(cents/kWh)

STATE	1997	1998
Connecticut	12.13	11.95
Maine	12.75	13.02
Massachusetts	11.59	10.60
Rhode Island	12.12	10.91
New Jersey	12.08	11.39
New York	14.12	13.66
Pennsylvania	9.90	9.93
Delaware	9.22	9.13
Illinois	10.43	9.85
Indiana	6.94	7.01
Ohio	8.63	8.70
Wisconsin	6.88	7.17
Iowa	8.21	8.38
Kansas	7.71	7.65
Missouri	7.09	7.08
North Dakota	6.27	6.49
Florida	8.08	7.89
Georgia	7.74	7.67
South Carolina	7.51	7.51
West Virginia	6.26	6.29
Kentucky	5.58	5.61
Alabama	6.74	6.94
Arkansas	7.80	7.51
Texas	7.82	7.65
Arizona	8.82	8.68
California	11.50	10.60
Montana	6.40	6.50
New Mexico	8.92	8.85
Wyoming	6.22	6.28
Oregon	5.56	5.82
Washington	4.95	5.03
U.S. Average	8.43	8.26

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[26] Source: U.S. Energy Information Administration. *Electric Sales and Revenue*, 1997 and 1998 editions. These data will not be meaningful after 1998 unless the Energy Information Administration changes the way it collects retail sales data and calculated prices. This is the case because the data do not now distinguish customers taking all of their electricity from the UDC from those which take generation services from an Energy Service Provider (ESP) and distribution and transmission service from the UDC.

TABLE 1B
AVERAGE REVENUE PER KWH
INDUSTRIAL CONSUMERS[27]
(cents/kWh)

STATE	1997	1998
Connecticut	7.76	7.70
Maine	6.36	6.61
Massachusetts	8.78	8.18
Rhode Island	8.52	7.61
New Jersey	8.11	7.94
New York	5.20	4.95
Pennsylvania	5.89	5.63
Delaware	4.82	4.65
Illinois	5.29	5.11
Indiana	3.91	3.95
Ohio	4.16	4.30
Wisconsin	3.72	3.86
Iowa	3.95	3.99
Kansas	4.51	4.46
Missouri	4.46	4.43
North Dakota	4.38	4.30
Florida	5.04	4.81
Georgia	4.13	4.23
South Carolina	4.00	3.69
West Virginia	3.47	3.78
Kentucky	2.80	2.91
Alabama	3.71	3.89
Arkansas	4.45	4.16
Texas	4.05	3.94
Arizona	5.05	5.12
California	6.95	6.59
Montana	3.66	3.19
New Mexico	4.42	4.47
Wyoming	3.46	3.38
Oregon	3.23	3.50
Washington	2.59	2.64
U.S. Average	4.53	4.48

[27] Source: U.S. Energy Information Administration. *Electric Sales and Revenue*, 1997 and 1998 editions. These data will not be meaningful after 1998 unless the Energy Information Administration changes the way it collects retail sales data and calculated prices. This is the case because the data do not now distinguish customers taking all of their electricity from the UDC from those which take generation services from an Energy Service Provider (ESP) and distribution and transmission service from the UDC.

As White (1997) discusses, whatever the public interest rationale for adopting the reform model depicted in Figure 4, the primary political stimulus for these reforms was the gap that existed between the regulated embedded cost of generation services and the market value of those services. The gap in places like California and the Northeast appeared to be very large indeed. Consumer interest groups wanted their constituents to avoid paying for some or all of this price gap, and independent power supply interest groups wanted the opportunity to compete against it to supply power to distribution companies or directly to retail customers.

How could such a large price gap emerge? There are three key factors.

1. U.S. utilities added nearly 100,000 Mw of nuclear capacity during the 1970s and 1980s. This capacity was built under the assumption that fossil fuel prices would continue to rise and to reach very high levels by the end of the century. These facilities cost much more than anticipated to build, cost much more to operate, and operated at lower levels of reliability than had been anticipated. The average total cost of nuclear facilities is frequently significantly higher than the current price of electricity in the wholesale market or the projected total cost of new generating plants using the most efficient technologies. While the incremental (going forward) cost of many nuclear facilities apparently makes it economical to continue operating them based on competitive market revenues, some nuclear facilities are probably not economical to continue running, even on an incremental cost basis.

2. Utilities in some areas of the country (especially California and the Northeast) were required to purchase too much QF capacity at too high a price under long term take and pay contracts. Part of the problem results from bad luck in forecasting future capacity needs and future fossil fuel prices. However, the problem is also a consequence of the politicization of the resource acquisition process and the ability of QF interests to "capture" the regulatory process so as to increase the demand for, and price of, the power produced by these facilities.

3. Probably the most important factor, however, is the abundant supply and very low price of natural gas available throughout the U.S. combined with the development of high-efficiency gas-fueled Combined Cycle Generating Technology (CCGT). We can credit development of the CCGT technology, in turn, partially to the demand for it in some QF facilities.[28] CCGT plants have much smaller minimum efficient scale than the coal and nuclear plants upon which the industry had relied, were easier to site, could be built more quickly and with better cost controls, were more thermally efficient, and produced less pollution. Together, these factors have significantly reduced the long run marginal cost of generating electricity. Twenty years ago natural gas was viewed as a very scarce commodity whose price would rise significantly over time and that was too valuable to burn to produce electricity.[29] QF contracts designed by the California commission in the mid-1980s assumed that oil and natural gas prices would rise to the equivalent of $100/barrel by the end of the century. Instead of being too valuable to burn, natural gas has become the fuel of choice for new generating plants in most parts of the country. Base-load electricity from CCGT technology can be produced for roughly 3 cents/kWh in many parts of the country. QF contracts in California required utilities to pay as much as 11 cents/kWh in capacity and energy charges, however, and the average QF contract called for payments above 7 cents/kWh in 1995.

Organized customer groups (primarily industrial customers) in states where C_G was substantially greater than P_{CG}, recognized a potential benefit from getting the right to buy unbundled distribution and transmission service at a regulated price from the local utility, so that they could then use these delivery services to acquire generation services directly (or through intermediaries) in the wholesale market at prices far below the regulated prices for generation. An unbundled retail competition model also gave independent power developers an opportunity to go after *all* of the electricity demand then served by incumbent utilities at

[28] Perhaps more important, though, were the developments in efficient jet engine technology developed for aircraft which have been applied directly to combustion turbines that were the key innovation in the CCGT technology.

[29] Indeed the Fuel Use Act of 1978 restricted the use of natural gas in utility boilers.

above market prices, rather than just serving utilities' incremental generating capacity needs through what were effectively resale arrangements. To potential wholesale energy marketers, some of whom got their start in the rapidly developing deregulated wholesale and retail markets for natural gas, a larger competitive generation market created new opportunities to sell the transaction and risk hedging skills they had developed in the gas markets in another market. Environmental groups, which had effectively exploited the institution of regulated monopoly to pursue their goals (via taxation by regulation) in states like California, New York, and Massachusetts to subsidize renewable energy facilities and energy efficiency programs, perceived the demise of vertically integrated monopolies as a threat to these initiatives. There was concern in groups representing residential and small commercial consumers, that unbundling and retail competition would lead to smaller customers getting stuck with a large share of the strandable costs, as they perceived had been the case in the natural gas and telephone sectors as a consequence of similar reforms that were being implemented in those sectors. And for utilities in the high cost states, the prospect of actually having the difference between their regulated costs and the market value of generation services "stranded" represented potential financial disaster.

Strandable cost[30] estimates made in the mid-1980s varied from about \$100 billion to about \$200 billion, with these strandable costs heavily concentrated in California, New England, New York, New Jersey, Pennsylvania, Illinois, Arizona, and a few other states.[31] Regulators estimated that the stranded costs for the electric utilities in Massachusetts were roughly \$9 billion, or about double the equity in these companies.[32] In California, strandable costs were estimated to be about \$25 billion, again more than twice the equity investment on the companies' books. In both cases, the estimated strandable costs were roughly equally divided between nuclear power plant investments and QF/IPP contract costs.

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[30] It is useful to distinguish between "strandable costs" which are potentially not recoverable by a utility if it sold its generation at market prices and costs that actually have to be written off (are stranded) as a result of the actual competition and cost recovery rules eventually adopted.

[31] For example, Moody's estimated strandable costs at about \$130 billion in 1995, most of which had either been mitigated through asset sales or regulators and legislators had allowed utilities to recover through non-bypassable distribution charges by 1999. "Moody's: Stranded Costs Sink to About \$10 billion," Electricity Daily, October 29, 1999, page 2.

[32] DOER Report: 1998 Market Monitor, Division of Energy Resources, Commonwealth of Massachusetts, September, 1999, page 25.

In light of these facts, it should not be surprising that industrial customer groups, independent power plant developers and electricity marketers actively promoted an unbundling with full wholesale and retail competition model *without* stranded cost recovery provisions. Utilities, and initially some environmental groups, opposed a full retail competition model aggressively, while representatives of residential consumers focused on finding ways to ensure that small customers received the same benefits from restructuring and competition that the large industrial customers received. Nor should it be surprising that the battle was fought initially in those states where the potential benefits of shopping directly in the wholesale market to avoid paying for strandable costs or competing to undercut the prices charged by incumbent utilities with stranded costs were greatest. That is, where the "price gap" was largest. Indeed, the serious debate about full unbundling, wholesale, and retail competition began at the state level, primarily in California, Massachusetts, New York, Rhode Island, and Illinois.

STATE ELECTRICITY COMPETITION AND RESTRUCTURING INITIATIVES

Electricity sector reforms differ from the reforms that have taken place in the U.S. telephone, natural gas, and transportation sectors in at least one important respect. In these other sectors, the initiatives for major structural, regulatory and pro-competition reforms were largely federal. The states typically resisted reforms or played a limited role. In electricity, federal initiatives got the ball rolling, but it was the states that have initiated the most fundamental reforms. As I have discussed, FERC and Congress, through EPAct92, led initiatives to open up transmission systems to support wholesale competition and to create a framework that facilitated the development of competitive markets for wholesale generation services. But these initiatives proceeded largely within an "incremental wholesale competition" model that revolved around incumbent utilities' arranging for the generation supplies required by their "native load" retail customers which they expected to continue to serve exclusively. Prior to the mid-1990s, this approach also reflected the preferences of the states, which made considerable political efforts to preserve their jurisdiction over retail electric utility supply and pricing decisions.

Accordingly, neither EPAct92 nor FERC regulations required vertically integrated utilities to buy any (let alone all) of their generation supply needs through competitive procurement, nor did they make competitive generation service supplies available to retail customers by requiring unbundling of generation from distribution service and direct access to retail consumers over utility distribution systems. Retail supply obligations were still assumed to be assigned to the local distribution utility and subject to state regulation of prices, costs, and generation procurement decisions. States could then decide exactly how the local utility's obligations to supply retail customers would be met: by building new generating plants subject to cost of service regulation; by procuring all incremental generating capacity needs through competitive tenders; or from a mix of generating plants the utility owned and generation supplies it purchased in the wholesale market.

The stimulus for more fundamental industry structure, regulatory and competition reform came from California and a small set of pioneer states with relatively high electricity costs (and associated strandable costs) and a substantial QF/IPP presence. They responded to pressure from industrial consumers to adopt policies that would reduce the price of electricity and to pressures from IPP interests for an increase in their supply opportunities. California's restructuring initiative was instrumental in defining the basic framework for electricity sector restructuring that over twenty states have now followed and that several more states (and the U.S. Congress) are in the process of considering adopting in some form in the future. Table 2 lists the states that adopted comprehensive electricity sector reforms, including retail competition, as of December 1999. States are listed by the date they passed the relevant regulations and/or legislation. The dates in parentheses indicate when direct retail access to the wholesale power market starts, and the date when all retail customers will have retail competition options in each state. Several states in Table 2 have adopted reform programs but have not yet implemented them. Finally, Table 2 displays the average retail price for electricity in 1997 in the states implementing comprehensive reforms in each year and the average retail price for states that have not yet adopted such reforms. Note that, so far, the state reform initiatives have proceeded with no new federal mandates or obligations beyond those included in EPAct92 and FERC wholesale power market and transmission regulations made under its existing legislative authority.

a. California Starts the Ball Rolling

High electricity rates became a major issue in California in the early 1990s in the context of general concerns about the future of the state's economy stimulated by a severe recession and the loss of manufacturing jobs following cutbacks in defense spending following the end of the Cold War. Industrial customers became very aggressive in seeking regulatory and tax relief to help them to reduce their costs to remain competitive with firms in other states. In April 1994, the California Public Utilities Commission (CPUC) issued a report (known as the "Blue Book") that laid out a set of major proposed structural and regulatory reforms for the electric power sector, including a schedule to phase in retail wheeling (also called " retail direct access" and “retail customer choice”).[33] The Blue Book proposals included the introduction of Performance Based Regulation (PBR) to replace traditional cost-of-service/rate-of-return regulation for distribution service, unbundling of generation from transmission/distribution services, retail competition (“direct access” or “customer choice”), and a Competition Transition Charge (CTC) to allow utilities to recover the "uneconomic" portion of their embedded generation costs and QF contract obligations --- their strandable costs.[34]

The debate that followed the issuance of the Blue Book attracted participants from all over the country and was quite contentious. It was clear that whatever happened in California could have important implications for the rest of the country. While utilities initially resisted the proposals for unbundling and retail competition, they soon focused their attention on getting commitments to allow the recovery of their potentially stranded costs through a Competitive Transition Charge (CTC). Major differences of opinion have also emerged regarding the institutional changes required to support a fully competitive electricity sector (Joskow, 1996). In early 1996, the CPUC issued its long-awaited restructuring decision.[35] Later that same year, the California legislature passed a restructuring law (AB 1890) that largely followed the architecture delineated by the CPUC’s restructuring order, but that also included a number of significant refinements. Taken together the major provisions of AB 1890 and CPUC electricity sector restructuring regulations include:

a. Retail “customer choice” or retail wheeling: effective in 1998, all retail customers were given the ability to choose an ESP to provide them with generation service or can continue to receive “default service” from their local utility distribution company (UDC).

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[33]Proposed Policy Statement on Restructuring California's Electric Services Industry and Reforming Regulatory Policy, April 20, 1994.

[34] Several of the then sitting Commissioners have also told me that their visit to England and Wales in early 1994 to study the competitive electricity system that had been created there in 1990 greatly influenced their decision to endeavor to create a similar system in California.

[35] Decision 95-12-063 (December 20, 1995) as modified by Decision 96-01-009 (January 10, 1996).

b. IOUs must provide open access to their transmission and distribution networks to competing generators, wholesale marketers, and ESPs at prices determined by FERC and the CPUC.

c. The prices charged by vertically integrated utilities are unbundled to separate generation charges (and some retailing charges) from UDC distribution and transmission charges that are not open to competition and continue to be regulated.

d. The UDC's default service energy price, charged to customers who do not choose an ESP, is (effectively) set equal the wholesale generation spot market price attributed to each retail customer's consumption (based on hourly metering or group load profiling), adjusted for physical losses, plus avoidable billing and metering costs. This is the "price to beat" for ESPs.

e. Provisions are made for utilities to recover their stranded costs, which include incentives to divest generating assets and to renegotiate QF contracts. Stranded costs associated with most utility generating assets must be recovered over a four year period during which retail rates are generally frozen at their 1996 levels, with the exceptions noted below. Stranded utility generation costs are then recovered from the difference between the regulated retail prices in effect in 1996, the utility's actual distribution and transmission costs, and the wholesale spot market price of generation service. Stranded utility generation costs that cannot be recovered during this rate freeze period must be absorbed by the utility. All utility-owned generating assets must be "market valued" by the end of the rate freeze (special provisions apply to the nuclear plants) and rely entirely on market revenues to cover their costs after that date. Stranded costs related to QF contracts can continue to be recovered after the rate freeze period ends through a non-bypassable distribution charge.

TABLE 2

COMPREHENSIVE STATE RETAIL COMPETITION PROGRAMS
(Start Date /All consumers eligible date)

1996	1997	1998	1999
California (1998/1998)	Massachusetts (3-98/3-98)	Arizona(10-99/1-2001)	New Jersey (11-99/11-99)
NH (1998/1998-Delayed)	Illinois (10-1999/5-2002)	Connecticut (1-2000/7-2000)	Arkansas (1-2002/6-2003)
NY (1998/2001)	Maine (3-2000/3-2000)		Delaware (10-99/10-2000)
Pennsylvania (1/99-1-00)	Montana (7-98/7-2000)		Maryland (7-2000/7-2002)
Rhode Island (1-98/1-98)			New Mexico (1-01/1-2002)
			Ohio (1-2001/12-2005)
			Oregon (Except residential)
			Texas (1-02/1-02)
			Virginia (1-02/1-04)

Average IOU Electricity Prices (1997):

10.4 cents/kWh	8.3 cents/kWh	9.5 cents/kWh	6.8 cents/kWh

Other States: 5.6 cents/Kwh

As of December, 1999

f. AB 1890 enabled utilities to "securitize" a fraction of their stranded costs by issuing bonds whose interest and amortization is guaranteed by the state to be paid out of stranded cost charges that utilities are authorized to include in their distribution charges. Essentially, these provisions make it possible for utilities to refinance a portion of their generating assets with 100% highly rated debt instruments, replacing the roughly 50/50 debt to equity ratio with which the generating assets had been financed and the associated financing costs reflected in the regulated prices upon which the rate freeze are based. Securitization was designed to reduce the utilities' cost of capital and income taxes associated with carrying stranded costs. (In other words, a legislative promise of stranded cost recovery is easier to take to the bank than a regulatory promise.)

g. Residential and small commercial customers received an immediate 10% price decrease from then prevailing regulated prices, financed by the cost savings from securitization. (So, the retail prices for these customers are frozen for four years at 10% less than the prices in effect in 1996.)

h. Distribution and any remaining state-jurisdictional transmission charges are regulated using incentive regulation mechanisms, or what is now referred to in the U.S. regulatory arena as Performance Based Regulation (PBR).

i. The IOUs were directed to help to create two new non-profit transmission network operation and wholesale market institutions. The first is the California Independent System Operator (CAISO), which operates the transmission networks owned by the three major California IOUs and is responsible for running various energy balancing, ancillary service, and congestion management markets that I will discuss presently. The second is the California Power Exchange (CALPX), which runs day-ahead and hour-ahead public wholesale markets for sales of energy. Both CAISO and CALPX are non-profit corporations with governing boards that include representatives of major interest groups as well as "public interest" members.

j. During the rate freeze period, IOUs must procure the electricity supply needs of default service customers from the CALPX and CAISO, and must sell into the PX and CAISO, any electricity they produce from generating plants they own and from pre-existing wholesale power purchase contracts, including power supplied to them under QF contracts.

k. The two largest IOUs were ordered to "volunteer" to divest at least half of their fossil generating capacity in California to mitigate horizontal market power problems. [36]

The restructuring and competition programs adopted by most states have included many of the same elements as those adopted in California. The following key elements are included in most state plans, though there are some significant variations in them from one state to another:

a. Resolution of stranded cost recovery issues: A critical part of the structuring "deal" in most states is a set of provisions that gives incumbent utilities an opportunity to recover a large fraction of their stranded costs through some type of non-bypassable stranded cost charge that is assessed to all customers as a component of regulated monopoly distribution service. Either ex ante or ex post, stranded cost values are determined by some combination of market valuation of generating assets and QF contracts (through auctions) and administrative valuations based on projections of future market prices for energy and capacity. States vary in what concessions they have extracted from utilities in return for assurances regarding stranded cost recovery. The New England states, New York, and California have either required or given utilities strong financial incentives to divest their generating facilities to value their stranded costs and to reduce the risks associated with future recovery. New Jersey and Pennsylvania have placed much less pressure on utilities to divest their generating facilities, and have relied more on ex ante administrative determinations and ex post valuations to come up with values for recoverable stranded costs. The Texas restructuring law appears to require utilities to divest at least some of their generating capacity. Utilities in these states have sometimes been willing to trade

[36] All three IOUs ultimately divested all of their fossil-fueled generating capacity in California. Generation divestiture is discussed in more detail below.

more risk of stranded cost recovery for greater opportunities to retain their generating businesses and to compete in the retail market.

b. Market pricing of wholesale generation service and market valuation of generating assets: Once stranded cost recovery provisions are adopted, utilities that continue to own generating facilities must look to the market for revenues to cover the going forward and residual sunk costs of their generating assets. Effectively, generating plants are deregulated and cost-of-service regulation of generation service costs comes to an end.

c. Unbundling of monopoly transmission, distribution, and various "public benefits" obligations from the costs of generation services combined with regulations providing for "customer choice" of their generation service suppliers: Access to the utility's distribution system for delivery of electricity at a separate regulated delivery charge gives retail consumers the opportunity to purchase unbundled generation service from competing Energy Service Suppliers (ESPs). The alternative approaches that states have taken to "retail competition" and the results of these programs to date are discussed in a separate section below.

d. The creation of wholesale market institutions to support sales by competing generators and purchases by distribution companies, ESPs and marketeers in competitive markets, in a way that respects the special physical attributes of electricity and the need to maintain the reliability of the transmission network: This includes the development of organized markets for energy and ancillary network support services, network congestion management protocols, and physical and financial metering and settlement mechanisms which recognize that electricity is supplied to and withdrawn from a common pool, so that one supplier's electrons cannot be physically distinguished from another's. The development of these institutions has necessarily been a joint venture between the states and FERC since, on the one hand, the structure of wholesale market institutions and transmission arrangements are exclusively FERC jurisdictional, while on the other hand, FERC has found it necessary to adapt its rules to support different states' variations on this basic restructuring theme.

e. The creation of, and provisions to finance, various "public benefits" (subsidy) programs for energy efficiency, renewable energy technology, and for special low-income rates. These programs are paid for through non-bypassable charges that are added to the monopoly distribution prices paid by all retail consumers who use the distribution network.

f. The development and application of PBR mechanisms to replace traditional cost-of-service regulation of residual monopoly distribution services: These schemes typically involve the application of a variant of a "price cap" mechanism. These mechanisms are designed to give distribution utilities incentives to control costs and to relieve the regulatory agency of the need to reset distribution rates frequently.

g. Mandatory rate reductions (3% to 15%) for all or a subset of customers, whether or not they choose to be supplied with generation service from an ESP or continue to purchase electricity from their local UDC: These rate reductions are paid for from the cost savings from securitization, sales of generating assets at prices above their book value historically used to set regulated prices, and by squeezing the profits of the utilities. (So, 100% stranded cost recovery may really be less than 100%). In some states, regulated rates would have fallen anyway under then prevailing regulated pricing arrangements, so that the mandatory rate reductions (or rate freezes) may not have been as financially painful as may first meet the eye.

The first movers in 1996 and 1997, listed in Table 2, were primarily states with high electricity prices, utilities with significant potential stranded costs, earlier aggressive policies to encourage QFs, large subsidized energy efficiency programs, and influential environmental groups that had been active in the formulation of (expensive) electricity policies in the last decade. (Montana is the primary outlier and restructuring initiatives there appear to have been promoted by the state's single large private utility). Excluding Montana, all of the states listed in Table 2 had electricity prices far above the U.S. average. By 1999, we begin to see a number of states which do not have extremely high (relatively) electricity prices and stranded costs (e.g. Oregon, Ohio, Maryland, Arkansas, Texas) adopt comprehensive restructuring programs. It should be noted, however, that these later programs often involve a much more gradual phase in of retail access and customer choice, and involve much less pressure on utilities to divest their generating assets. Overall, it is still the case that the states that have adopted comprehensive reform initiatives are those with above-average embedded generation costs and have utilities with sufficient potential stranded cost problems that the resolution of these problems became a useful bargaining chip for state policymakers. Nevertheless, while some low-cost states have rejected restructuring programs (e.g. Wyoming and Wisconsin), others are well along the path toward passing restructuring laws that provide for wholesale and retail competition.[37]

At this point, the reader may wonder how a state could adopt a policy that both provided stranded cost recovery for utilities and provided rate decreases for consumers that would not have been realized under the old regime. Theoretically, the combination of stranded cost recovery and the ability of consumers to buy electricity at its competitive market value should net out to zero (except perhaps for timing) since stranded costs represent the difference between the market value of a utility's generating plants and their book value. How is this magic accomplished? There are several factors at work here. First, several utilities have, in fact recovered less than 100% of their stranded costs through this process. They are earning less on the portion of their generating assets that have been deemed to be stranded than they earned under the old regime. Second, some of the rate reductions that have been advertised as resulting from restructuring would have been realized under the pre-existing regulatory arrangements as a result of lower fuel, depreciation, and QF costs. Third, generation divestiture has yielded market values that were far higher than utilities and their regulators had expected (more on this below).[38] The credits against stranded costs have reduced significantly the balance that is reflected in consumer rates and this has not (yet) been balanced by higher wholesale market prices. Fourth, most states have adopted stranded cost "securitization" programs which, as I have already discussed, create financing cost and tax savings that are passed on to customers. Finally, some of the rate reductions involve deferring recovery of some costs. These stranded costs will ultimately find their way back into distribution charges, stranded cost charges, or wholesale power prices in the future.

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[37] "West Virginia Adopts Dereg Plan to Send to Legislature," *Megawatt Daily*, February 1, 2000, page 1; "Oklahoma to Consider Final Restructuring Bill," *Megawatt Daily*, February 7, 2000, page 1.

[38] If the prices paid for divested assets reflect anticipated efficiencies that the new owners will bring to the system or the winner's curse, retail customers will benefit overall. If the prices paid for the divested assets merely reflect higher expected wholesale prices that the new owners expect to realize when they sell electricity in the unregulated market, this suggests that stranded costs had been overestimated because competitive wholesale market prices had been underestimated.

RESTRUCTURING TRENDS STIMULATED BY COMPETITION AND REGULATORY REFORM

The competition and regulatory reform initiatives by the federal government and various states has stimulated important structural changes in the electric power industry as well. I will discuss four of these structural in this section: (a) divestiture of generating plants; (b) mergers of electric utilities; (c) mergers of electric utilities with gas distribution and pipeline companies; and (d) entry of merchant generating plants.

a. Divestiture of Utility Generating Plants

Common ownership of generating capacity and the transmission network that the generators depend upon creates potential competitive problems when the transmission operator's generating plants compete with generating plants owned by third parties using the same network. Orders 888 and 889 specify transmission access pricing rules, information availability rules, and various behavioral rules designed to guard against discriminatory practices by the transmission owner. The creation of Independent System Operators (ISOs) to operate the transmission systems owned by vertically integrated utilities is a related approach to dealing with these problems. Since both approaches effectively require transmission owners to behave as if they are not vertically integrated, so that the economies of vertical integration are lost anyway, it is natural to ask if a structural solution to these vertical control problems, which would require vertically integrated utilities to divest either their generating assets or their transmission assets, would be a superior approach (a structural solution was applied, for example, to AT&T in 1984 when the BOCs were divested). While some policymakers favored a structural solution along these lines, it was generally viewed as being politically infeasible to require vertically integrated utilities to divest their generating plants.[39]

One of the surprising outcomes of the state reform programs has been a significant amount of "voluntary" divestiture of generating facilities by incumbent vertically integrated utilities. States promoted divestiture as a means of dealing with stranded cost valuation and to alleviate market power concerns. Basically, the stranded cost recovery mechanisms have sometimes been structured to provide more favorable financial outcomes to utilities that market-valued their generating assets by auctioning them off to third parties rather than

[39] Recall that the breakup of AT&T resulted from the settlement of a federal antitrust case.

relying on administrative procedures to value the assets. Some states have also encouraged utilities to divest generating assets to deal with perceived vertical market power problems associated with common ownership of generating and transmission assets and, in the case of California, in response to concerns about horizontal market power in wholesale power markets. Finally, as state restructuring programs deregulated generation services and required utility-owned generating plants to rely on market prices to cover their costs (net of any stranded cost allowances), some utilities simply made the business judgement that they would focus their business strategies on regulated transmission and distribution service. Accordingly, they decided to get out of the generation business by selling their plants to companies that had decided to focus on the merchant generating plant business.

Table 3 provides data on utility divestitures of generating assets from 1997 through late December 1999. Nearly 90,000 Mw of generating capacity has been sold or is for sale, accounting for over 15% of the IOU generating capacity in the U.S.[40] However, it is evident that divestiture of generating plants has been concentrated in those regions where state electricity restructuring and competition programs have been enacted and where incumbent utilities had significant stranded cost burdens. Indeed, aside from Montana, and a pending sale to respond to horizontal market power problems raised in connection with a merger involving American Electric Power (AEP) and Central and Southwest (CSW), utilities in states which did not have significant stranded cost problems or without a comprehensive state restructuring and retail competition program, have divested no generating assets so far. Utilities in New England, New York, California, and Illinois have sold off, or are in the process of selling off, almost all of their fossil generating capacity. Some utilities in New Jersey, Pennsylvania, and Delaware have divested generating assets, while others have resisted pressures to do so.

Table 4 lists of all sales of utility fossil and hydroelectric (mostly fossil) generating capacity for which I was able to obtain both the sale price of the assets and their net book value used for regulatory purposes. I am confident that these data are representative of the larger population of fossil and hydro generating assets sales. Recall that a utility's potentially strandable costs are equal to the difference between the net book value of the plant used for determining regulated prices and the market value of the plant. This is the case because cost of service regulation uses a rate base equal to the original cost of the plant net of depreciation

[40] There were 582,000 Mw of IOU generating capacity in 1997.

(Joskow and Schmalensee 1986). Annual capital charges included in the regulated prices charged to customers are then supposed to be equal to the annual depreciation of the plant's book value plus a return on the rate base equal to the firm's cost of capital times the net book value of the plant (with adjustments for taxes). If these regulatory cost accounting and pricing procedures work perfectly, then the NPV of future revenues (net of operating costs) earned by the plant should equal its net book value at every point in time (Schmalensee !989)).

TABLE 3

GENERATION DIVESTITURES
(MW)

State/Region	1997	1998	1999	For Sale	TOTALS
California	10,077	7,853	-	4,230	22,160
New England	6,009	4,552	4,394	4,296	19,251
New York	-	5,222	6,775	2,080	14,077
PJM	-	6,898	3,942	5,320	16,160
Illinois	490	1,108	10,350	-	11,948
Other	-	1,556	-	3,580	5,136
TOTALS	16,576	27,189	25,461	19,506	88,732

As of December, 1999

Source: Energy Information Administration, Dow Jones, Trade Press, Company releases and filings.

TABLE 4

MARKET AND BOOK VALUES FOR DIVESTED HYDRO AND FOSSIL GENERATORS

(through December 1999)

SELLER	BUYER	BOOK VALUE ($millions)	MARKET VALUE ($millions)	($/kW)	MARKET/ BOOK
NEP	PG&E GEN	1,100	1,590	(397)	1.44
SCE	Various	421	1,115	(148)	2.65
PG&E	Southern	430	801	(296)	1.86
Boston Edison	Sithe	450	536	(271)	1.19
CMP	FPL	340	846	(714)	2.49
ComEnergy	Southern	79	462	(470)	5.85
EUA	Southern	40	75	(268)	1.87
MainePS	WPSPower	12	37	(309)	3.08
Montana Power	PPL Global	650	988	(635)	1.52
Niagara Mohawk	Orion	250	425	(643)	1.70
SDG&E	NRG/Dynegy	94	356	(296)	3.78
Niagara Mohawk	NRG	370	355	(261)	0.96
GPU/NYSEG	Edison Mission	560	1,800	(950)	3.21
GPU	Sithe	815	1,680	(408)	1.98
ConEd	Keyspan	300	597	(275)	1.99
ConEd	NRG	250	505	(347)	2.02
ConEd	Orion	275	550	(296)	2.0
Unicom	Edison Mission	1,100	4,800	(510)	4.36

TABLE 4 (con't)

MARKET AND BOOK VALUES FOR DIVESTED FOSSIL GENERATORS

SELLER	BUYER	BOOK VALUE ($millions)	MARKET VALUE ($millions)	($/kW)	MARKET/ BOOK
NU	NRG	87	460	(206)	5.29
NU	NUGen	125	865	(650)	6.92
DQE	Orion	1,100	1,710	(654)	1.55

Sourse: Dow Jones, Trade Press, Company releases and regulatory filings.

Two things are immediately evident from Table 4. First, the market price per unit of capacity varies widely.[41] Second, the fossil and hydroelectric generating portfolios that have been auctioned off have almost universally been sold at a price that is in excess, sometimes far in excess, of the book value of the plants, suggesting either that the regulated charges for these plants were less than the competitive market value of the electricity they supply,[42] or that the new owners expect to operate the plants more efficiently, or a combination of both.[43]

[41] In general (not shown in the Table), coal-fired plants and hydroelectric facilities have sold for higher prices than older oil and natural gas-fired facilities. Assets have also fetched higher prices in regions where wholesale prices are expected to be high (and volatile) during peak periods in the next few years (e.g. the Midwest and PJM). This can be inferred from the futures contracts for delivery at various locations in the U.S. which are traded on the NYMEX.

[42] Under traditional regulatory cost accounting, the present discounted value of the future cash flows from a generating plant selling at regulated prices would be 1.0.

[43] In addition, it appears that some buyers have attributed significant value to the sites that the generating

This indicates that the stranded cost problems were not associated with utility portfolios of fossil and hydroelectric generating assets. Indeed, the sales of these assets at prices in excess of their book values have made a significant contribution to reducing the projected stranded costs associated with the entire generation portfolios of utilities, including nuclear facilities and QF contracts; most state restructuring plans require utilities to credit the excess of market price over book value against any stranded costs associated with nuclear plants, QF contracts, and other categories of stranded costs.

One of the great surprises that has emerged from this divestiture process is that a market for deregulated (from a pricing, not a safety perspective) nuclear power plants has emerged. Two companies, Entergy (a public utility holding company with vertically integrated utility subsidiaries in Mississippi, Arkansas, Texas, and Louisiana) and Amergen (a joint venture between PECO, a vertically integrated utility serving the Philadelphia area, and British Energy[44], the owner and operator of all of the nuclear plants in England and Wales), have actively sought to purchase nuclear plants from their vertically-integrated utility owners and to operate them as merchant plants which are not subject to economic regulation. As this is written, sales agreements have been made for eight nuclear power plants. The sales prices range from $16/kW to over $200/kW, though the reported values are difficult to interpret since the terms of the reported sales vary with regard to the treatment of fuel stocks, additional contributions to nuclear decommissioning funds, and associated purchased power contracts that some of the buyers have taken back. As Ed Kahn has observed, adjusting for these factors suggests that these plants have sold for very close to zero or even negative prices (Kahn (1999)). For example, he shows how the $121 million sales price announced by Boston Edison for its Pilgrim nuclear power plant might be interpreted as Boston Edison actually paying the buyer $176 million to take the plant when the value of fuel and Boston Edison's additional contributions to decommissioning funds are taken into account.[45] Any way you slice it, however, the sales prices for nuclear plants are far below their net book

plants are on in anticipation of adding additional generating capacity at these sites in the future.

[44] British Energy itself emerged from the restructuring and privatization of the electricity sector in England and Wales.

[45] Entergy also recently announced the purchase of about 1,800 Mw of nuclear assets from the New York Power Authority. The press headlines reported that "New York sells nukes to Entergy for $806 million," *MegawattDaily*, February 15, 2000, page 1. However, after taking account of the value of fuel, the mortgage provided by the seller, the value of intangible assets and a power contract with the seller, etc., the purchase price of the plant was no more than about $350 million.

values used for regulatory pricing purchases in the past, which are as high as $1000/Kw. As a result, these plants account for a large share of stranded costs.

The basic picture that emerges for the sale of nuclear plants that will subsequently be operated as "deregulated" merchant plants is that there are at least two buyers who will take a nuclear plant off your hands if they can get it by paying very little per unit of capacity to take it off the hands of the current owners and the seller fully funds the decommissioning trust. The buyers then hope that they can operate the plant profitably based on going forward costs and market revenues. The aggregation of existing nuclear assets into a smaller number of companies that can run the plants safely and economically, and have powerful financial incentives to close the plants if going forward costs rise relative to expected revenues is likely to represent a significant benefit of electricity restructuring and competition.

Table 5 lists the major buyers of the divested generating plants. Most of the buyers are affiliates of U.S. utilities which have entered the merchant plant business and are buying and building generating plants around the U.S. to supply in the competitive wholesale markets that are emerging. Two other buyers on the list (AES and Sithe) are independent companies that got their start as owners and operators of QF and IPP plants in the U.S. during the 1980s. Several of these companies (both utility affiliates and independents) also own generating plants in other countries (England and Wales, Ireland, Spain, South America, India, Pakistan, China, Indonesia) which allow independent power projects. Two of the companies have significant ownership interests from non-U.S. utilities. Most of these companies participate regularly in generation capacity auctions and we can anticipate that their portfolios will grow as more generating capacity comes up for sale and opportunities to develop new merchant plants continue to expand as demand grows and restructuring and regulatory reform proceed to other areas of the country.

TABLE 5

MAJOR BUYERS OF DIVESTED GENERATION
[As of January 25, 2000]

Company	MW Purchased	Affiliation
Edison Mission Energy	11,284	Utility
NRG	9,300	Utility
Southern	6,232	Utility
Sithe	6,117	Independent
AES	5,280	Independent
Orion	5,140	Utility/Wall Street
Amergen	4,206	Utility
PG&E Gen	4,009	Utility
Reliant	3,776	Utility
Duke	2,645	Utility
PPL Global	1,645	Utility

Source: Energy Information Administration, trade press, company releases and regulatory filings.

b. Utility Mergers and Acquisitions

Regulatory reform and the expansion of competitive opportunities in other previously regulated industries (e.g. telecommunications, railroads, airlines, trucking) has been accompanied by a significant amount of merger activity. The electric power industry appears to be following this trend.

Between 1935, when the Federal Power Act (FPA) and the Public Utility Holding Act (PUHCA) were passed, and the early 1990s, there were very few major mergers between electric utilities or between electric utilities and natural gas pipeline and distribution companies.[46] Indeed, the structure of the electric utility industry was effectively frozen as it existed in the 1930s (except for subsequent divestitures of geographically dispersed utilities controlled by interstate holding companies required by the SEC under PUHCA). FERC and state regulatory policies were hostile to mergers between proximate utilities. And PUHCA restricted mergers between electric utilities that did not operate as part of a single integrated system and placed an absolute ban on mergers between electric and gas utilities when the mergers involved registered holding companies. As a result, many regions of the country had a large number of relatively small vertically integrated utilities. When mergers were attempted, they often took many years to complete, regulatory reviews focused on often bazaar antitrust theories, required a showing that the merger would lead to substantial cost savings, often allowed the merged firm to retain little of any cost savings from the merger, and the associated hearings often became a circus that various interest groups used as a forum for addressing disputes with the merging firms that often had nothing to do with the proposed merger.

Deregulation of wholesale power markets, incentive regulation of distribution and transmission service, investment opportunities around the world, diversification opportunities in telecommunications and natural gas, etc., have led many utilities to look to mergers for cost savings and increased scale to support investments in other markets. In response to the growing interest in mergers, the regulatory environment in which utility mergers are evaluated has changed considerably in the last few years. In late 1996, FERC revised its merger evaluation standards to be (arguably) more compatible with the DOJ/FTC Horizontal Merger Guidelines.[47] FERC's merger reviews now focus primarily on the effects of a merger on competition in generation markets and on whether the merger unduly complicates the regulation of the remaining regulated components of the merging firms. Utilities need not demonstrate that the mergers will result in significant cost savings, though they typically make such a showing to support a public interest case for the proposed merger. Several state commissions have encouraged utilities to merge to reduce costs and have allowed utility shareholders to retain a substantial share of any cost savings resulting from mergers.

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[46] Though there are many combination gas and electric utilities, primarily dating from before the 1930s.

[47] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order 592, Issued December 18, 1996, 77 FERC ¶ 61,263.

EPAct92 removed many restrictions on foreign acquisitions by U.S. utilities. The SEC has become much more flexible in accommodating mergers between utilities that are not as closely integrated geographically, as well as mergers between electric and gas utilities which had previously been almost completely banned.[48]

What motivates utility mergers? The same things that motivate mergers in other industries. The introduction of incentive regulation mechanisms combined with the spread of wholesale and retail competition provides utilities with an incentive to reduce costs through any means, including mergers. The introduction of wholesale and retail competition gives utilities with generation and marketing skills, the opportunity to profit from them outside of their historical service territories. Moreover, utilities seeking to expand their activities to other areas of the U.S. and to other countries have concluded, rightly or wrongly, that they are too small to raise the capital necessary to compete effectively against the larger domestic and international utilities they must compete with around the world. They have looked to merger as a way to increase their scale. This view is not crazy. Most of the unregulated utility affiliates which have successfully expanded into the merchant generating plant business in the U.S. and abroad are affiliates of relatively large U.S. utilities. Finally, while combination gas and electric utilities (e.g. PG&E or Con Edison) have existed for more than a century, remaining independent gas and electric utilities now see opportunities to reduce costs and to market energy more effectively by combining with gas transmission and distribution utilities, and recent FERC and SEC policies have been friendly to these "convergence mergers" as well.

The result of this confluence of investment and acquisition opportunities created by electricity sector restructuring, regulatory reform, and the associated expansion of competitive opportunities in the U.S. and many other countries, combined with the more favorable merger regulatory environment that has accompanied it, is a dramatic increase in the number of mergers between electric utilities and between electric and gas utilities in the last few years. Table 6 lists the electric utility mergers initiated between 1995 and the present and indicates the primary states where the merging utilities operate.[49] The pace of

[48] As part of its enforcement of PUHCA, over the years the SEC had forced many electric utility holding companies to divest all of their gas utility and gas pipeline subsidiaries.

[49] Between 1988 and 1994, there were nine electric utility mergers consummated. Five involved mergers of very small proximate utilities, and one was an acquisition of a utility through a bankruptcy proceeding.

merger activity appears to be accelerating as competition opportunities expand, incentive regulation diffuses more widely, and regulators have become less hostile to mergers. Most of the mergers in Table 6 are between relatively small utilities serving proximate geographic areas and are typically motivated by cost-savings opportunities. A few of the mergers involve consolidations of utilities that are not in close proximity to one another (e.g. AEP and CSW, UNICOM and PECO, CP&L and Florida Progress) and reflect largely “strategic” values perceived by their respective managements, though the participant in these mergers too typically claim that they will enable significant cost savings as well. Two recent proposed mergers involve acquisitions of U.S. utilities by foreign utilities seeking to enter the U.S, market. Another two recent mergers involve companies that started out as independent power producers (AES and Dynegy) which have decided to acquire small vertically integrated utilities with low-cost generating capacity.

TABLE 6
ELECTRIC UTILITY MERGERS 1995-1999

Merging Companies (States)	Announcement	Completion
Wisconsin Energy (WI) + NSP (MN) (Primergy)	1995	Terminated (1997)
BG&E (MD) + PEPCO (DC/MD)	1995	Terminated (1997)
PS Colorado (CO) + Southwestern PS (TX) (New Century Energies)	1995	1997
Ohio Edison (OH) + Centerior (OH) (FirstEnergy)	1996	1997
Delmarva (DE) + Atlantic City Elec (NJ) (Connectiv)	1996	1998
Union Electric (MO) + CIPSCO (IL) (Ameren)	1996	1998
WPL (WI) + IES (IA) + Interstate Power (IA) (Alliant)	1996	1998
Allegheny (PA) + DQE (PA)	1997	In litigation
AEP (OH/WV/KY/IN) + CSW (TX/OK)	1997	In process
LG&E (KY) + KU (KY)	1997	1998
Western Resources (KS) + KCP&L (KS)	1997	Terminated (1/2000)

TABLE 6 (con't)

ELECTRIC UTILITY MERGERS 1995-1999

Merging Companies (States)	Announcement	Completion
Sierra Pacific (NV) + Nevada Power (NV)	1998	1999
ConEd (NY) + Orange & Rockland (NY)	1998	1999
Cal Energy (Independent) + MidAmerican (KS/MO)	1998	1999
AES (Independent) + CIPSCO (IL)	1998	1999
Boston Edison (MA) + CommEnergy (MA) (NSTAR)	1998	1999
Scottish Power (Scotland) + Pacificorp (OR/UT/WY)	1998	In process
National Grid (UK) + NEES (MA/RI/NH)	1999	In process
NEES (MA/RI/NH) + EUA (MA/RI)	1999	In process
UtilCorp (MO) + St. Joseph L&P (MO)	1999	In process
UtilCorp (MO) + Empire Dist Elec (MO)	1999	In process
Dynegy (Independent) Illinova (IL)	1999	2/2000
New Century (CO/TX) + NSP (MN)	1999	In process

TABLE 6 (con't)

ELECTRIC UTILITY MERGERS 1995-1999

Merging Companies (States)	Announcement	Completion
ConEd (NY) + NU (CT/MA/NH)	1999	In process
PECO (PA) + UNICOM (IL)	1999	In process
EnergyEast (NY) + CMP (ME)	1999	In process
CP&L (NC/SC) + Florida Progress (FL)	1999	In process
Sierra Pacific (NV) + Portland General Electric-Enron (OR)	1999	In process

As of February 6, 2000

Source: Dow Jones, trade press, company releases and filings.

Mergers between electric utilities continue to involve much more burdensome regulatory review procedures and generally take more time to complete than do mergers in other industries. In addition to passing through the standard Hart-Scott-Rodino pre-merger review process, approvals from state and federal (SEC, FERC, NRC) regulatory agencies are generally required. It takes at least a year, and as much as two years, to go through the state and federal reviews required to get the necessary approvals to consummate a utility merger. However, as time has gone by, these reviews have focused more on ensuring that the mergers "do no harm" to consumers of regulated services than on trying to extract payments from the merging companies for the privilege of obtaining regulatory approvals. That is, the focus has shifted to traditional "public interest" concerns and away from regulatory extortion.

Table 7 lists 14 major mergers between electric utilities and gas pipeline or gas distribution utilities in the last three years. This type of "convergence" merger would have been virtually impossible a decade ago. SEC, DOJ/FTC, and state regulatory policies discouraged mergers between electric and gas utilities on the grounds that electricity and gas were competing sources of energy. (NU's acquisition of Yankee Energy involves the acquisition of a natural gas distribution company that NU was forced to divest by the SEC only a few years ago.) At the same time, some gas and electric companies believe that there are opportunities for joint marketing of natural gas and electricity transportation services and for direct sales to end-use customers seeking to take advantage of unbundling and open access reforms that have been introduced in both sectors.

Regulators have been concerned about potential vertical market power problems emerging as a result of mergers between electric utilities with downstream generation businesses and natural gas pipelines that control supplies of natural gas used by actual or potential competing generators in the same downstream markets. The fact that natural gas fired generating plants are generally the lowest cost entrants into wholesale power markets has heightened these concerns. FERC's open access pipeline regulations and open access rules applied to gas distribution utilities in some states have led to the unbundling of the transportation of natural gas from the sale of commodity natural gas in ways symmetrical to the separation of generation from transmission and distribution in electricity. As a result, in states that have adopted these policies for both gas and electricity suppliers, joint ownership of transportation services should, ideally, not reduce end-use customers' opportunities to buy electricity and natural gas commodities from competing upstream suppliers. Nevertheless, open access rules cannot be monitored perfectly. As a result, regulators have attached conditions to some of these mergers to ensure that credible and enforceable open access policies are in place.

Finally, since the EPAct92 was passed, there has been a dramatic increase in foreign acquisition and investment activities by U.S. utilities. U.S. utilities now own distribution and transmission utilities in England and Wales, Germany, Argentina, Chile, Brazil, Australia, and New Zealand. Utility affiliates and U.S. independent power developers have acquired or developed generating facilities in these countries as well as in India, Pakistan, Ireland, Spain, Hong Kong, Indonesia, Thailand, China, and other countries. These developments are transforming the world's electric power industry from an industry characterized by a large number of local and national monopolies to an industry increasingly characterized by large multinational electric generation, transmission, and distribution companies that market their skills and deploy capital to expand electricity supplies around the world.

TABLE 7

SELECTED MERGERS BETWEEN ELECTRIC UTILITIES AND GAS PIPELINE AND DISTRIBUTION COMPANIES

Merging Firms	Date Announced	Date Closed
Houston Industries (Reliant) + NORAM	1996	1997
Texas Utilities + Ensearch	1996	1997
Duke Energy + PanEnergy	1996	1997
Puget Power + Washington Energy (Puget Sound Energy)	1996	1997
Enron + Portland General Electric	1996	1997 [sold to Sierra Pacific 1999]
Enova (SDG&E) + Pacific Enterprises (SoCalGas) (SEMPRA)	1997	1998
Tampa Electric (TECO) + People's Gas (Lykes)	1997	1997
NIPSCO + Bay State Gas (NiSource)	1997	1997
PG&E +Valero	1997	1997
CMS (Consumers Power) + Panhandle Eastern	1998	1999

TABLE 7 (con't)

SELECTED MERGERS BETWEEN ELECTRIC UTILITIES AND GAS PIPELINE AND DISTRIBUTION COMPANIES

Merging Firms	Date Announced	Date Closed
Northeast Utilities + Yankee Energy	1999	In process
Dominion Resources (VEPCO) + Consolidated Natural Gas	1999	1/2000
Wisconsin Energy + Wicor	1999	In process
Detroit Edison (DTE) +MCN Energy	1999	In process
Energy East (NYSEG) + CTG Resources	1999	2/2000
Energy East (NYSEG) + Berkshire Energy	1999	In process

As of February 3, 2000

Source: Dow Jones, trade press, company releases and regulatory filings.

c. Competitive Entry of Merchant Generating Plants

Competitive entry of new unregulated generating facilities owned by developers who take on construction and operating cost risks and have incentives to utilize the lowest cost technologies is likely to be one of the most important long term benefits of competitive electricity markets (Joskow, 1997). One of the consequences of the uncertainties about the direction of electric sector restructuring during the period 1992 through 1997 was little investment in new generating capacity. As a result, reserve margins have declined steadily in the last several years.[50] From 1992 to 1997, U.S. generating capacity increased by about 4%, with half due to QFs and IPPs. Between 1997 and 1998, there was a net decrease in U.S. electric generating capacity, reflecting little entry of new capacity and the retirement of some older plants, while electricity production increased by over 3% in that year. The societal costs of these uncertainties, as they may have affected generation investment incentives, were probably not very great, since (luckily) we entered the period of debate about electricity sector reform with substantial excess generating capacity in most regions of the country. Demand growth in the last three years, driven primarily by economic growth and unusually warm summer weather, has made it clear that the generating capacity situation is now getting very tight. This has been revealed by extraordinarily high wholesale market prices in many regions of the U.S. during the last two summers and by projections of supply shortages in some regions of the country for the next few years.

The growing demand for electricity, high wholesale market prices, and the gradual development of credible institutional arrangements that allow new generators to enter the market to compete in wholesale energy markets, has stimulated substantial interest in the construction of new unregulated merchant generating facilities by independent power developers. In New England alone, developers of over 30,000 Mw of generating capacity (in a system with about 24,000 Mw of generation resources today) have indicated an interest in entering the market.[51] In California, developers of over 10,000 Mw of merchant plant capacity have filed permit applications with the California Energy Commission for specific power plant projects and another 5,000 Mw of new generating capacity has been announced.[52] The Electric Power Supply Association reports that as of October 1999, there were 121,000 Mw of merchant plant announcements, up from 56,500 Mw in October 1998.[53] Most of the announced merchant plants are combined-cycle or single cycle generating

[50] North American Electric Reliability Council, Reliability Assessment (various years).

[51] DOER Report: 1998 Market Monitor, Division of Energy Resources, Commonwealth of Massachusetts, September, 1999, Appendix F.

[52] California Energy Commission, http://www.energy.ca.gov, February 6, 2000.

[53] Electric Power Supply Association, Press Release, October 27, 1999.

facilities that rely on natural gas as a fuel and utilize advanced combustion turbine designs that have dramatically increased thermal efficiency.[54]

Of course, announcing the intention to build a merchant plant and actually completing a new plant are very different things. New entrants must still find suitable sites, obtain siting and environmental permits, and find financing. The entire process from start to completion is shorter than it once was, but generally takes on the order of three years. Combustion turbines installed at existing sites can be developed much more quickly, in as little as one to two years. Many of the announced plants are unlikely to become real operating power plants. Nevertheless, a significant number of new projects are moving forward with construction and I expect that we will see them begin to come out of the pipeline and into service by next summer.[55] The large number of new generating projects seeking to enter the market is consistent with the rapidly falling reserve margins and rising forward prices for power in many areas of the country. Wholesale market prices have risen to levels that are sufficiently high that entry of modern generating facilities is very profitable in many areas of the country.

TRANSMISSION NETWORK AND WHOLESALE MARKET INSTITUTIONS TO SUPPORT COMPETITIVE WHOLESALE POWER MARKETS

The core of most electricity sector reforms is the creation of reasonably competitive wholesale spot and forward markets for electric energy, capacity, a variety of operating reserve services (also referred to as ancillary services), plus free entry of new generating capacity to make sales in these unregulated power markets. As in other commodity markets, these markets play the traditional role of balancing supply and demand and allocating supplies among competing generators in the short run and provide economic signals for entry of new suppliers in the long run. However, wholesale electricity market mechanisms also play another important role. They are relied upon to provide generation resources, and economic signals for using these resources efficiently, that the operator of an electric power transmission network must rely on for maintaining the reliability and power quality of the

[54] See, for example, *Public Utilities Fortnightly*, January 20, 2000, pp. 26-30.

[55] Since these are general independent power projects, the hard data on them is quite poor since the DOE does not collect good information on these plants and they do not get captured in the standard NERC forecasts until after they are under construction.

network (frequency, voltage, and stability) and to manage congestion and related network constraints at the same speed at which electricity supply and demand attributes change -- which is very fast.

These resource allocation functions were traditionally performed within vertically integrated firms using internal scheduling, dispatch, and emergency response protocols that depended on a combination of computer optimization routines, marginal cost signals, and "band aids" applied by system operators to deal with unusual circumstances. The short run operating functions and the associated physical attributes of electric power systems that I just listed are perhaps the primary factors that led to vertical integration between generation and transmission. They are also the most challenging resource allocation activities to mediate through market mechanisms (Joskow, 1997).

Most countries that have restructured their electric power sectors to rely on wholesale and retail competitive markets (e.g., England and Wales, Argentina, Chile, Norway, New Zealand, Australia) to allocate generation service resources have also introduced new institutions to govern the operation of transmission networks and the competitive market trading of wholesale electric energy and ancillary network support services. Some regions of the U.S. have followed these examples and created new transmission operation and wholesale market institutions organized around not-for-profit Independent System Operators (ISO). These regions include California, New England, New York, and the states covered by P-J-M, where most state-initiated electricity restructuring has taken place. [56] With the exception of California, all of these regions had multilateral centrally dispatched power pools in existence for many years prior to the recent reform initiatives, and the wholesale market reforms that have been introduced have built upon these regional power pool institutions. Other states (e.g. Illinois and Michigan) have proceeded with restructuring and competition without major changes in transmission and wholesale market institutions, relying instead on traditional bilateral wholesale trading arrangements mediated by vertically-integrated control area operators who are subject to the regulations governing transmission system operators specified in Order 888 and Order 889. (Many of the states in the latter category are in regions where few other states have moved forward with comprehensive wholesale and retail competition and restructuring programs.) Private power exchanges (e.g. the Automated

[56] There is also a "loose" ISO covering some systems in the Midwest which is not yet operational and an ISO covering the interconnected transmission system in Texas (ERCOT).

Power Exchange), standardized trading hubs, and associated public futures and options markets have also developed alongside organized public markets for electric energy and ancillary network support services.

The physical and economic attributes of electricity demand, supply, and AC transmission networks have important implications for institutional design and the potential for market power problems. For competitive electricity markets to work reasonably well, there must be a single independent network operator responsible for maintaining the physical integrity of the network and for making use of resources made available to it to keep supply and demand in balance, manage congestion, call on operating reserves, and maintain certain physical parameters of the network such as voltage, frequency, and stability (Hogan, 1999). "Independent" means that the network operator's behavior is not influenced by the financial interests of suppliers and traders using the network. Ideally, the geographic expanse of the network operator should cover a large enough region to internalize network congestion and operating constraints and to encompass most of the trading relationships. Policies affecting market structure and market rules also need to be sensitive to potential horizontal market power problems that may arise as a consequence of the interaction between concentrated ownership of certain types of generating capacity, very inelastic demand, non-storability and inelastic supply, real-time physical balancing of demand and supply to maintain network service quality (e.g. 60 Hz frequency) and reliability, network congestion, and repeated interaction between generation suppliers.

Competitive generation markets on electric power networks are most appropriately conceptualized as spatial markets with demand (or loads) and differentiated generators dispersed across the network's geographic expanse. These demand and supply locations are generally referred to as "nodes" on the network. Though the generation suppliers produce more or less the same product -- electric energy (reserve services and differences in adjustment speeds complicate this) -- they are differentiated from one another along three major dimensions: (a) marginal costs of production, (b) transportation costs due to congestion and thermal losses, and (c) the speeds with which they can adjust their output from one supply level to another, including starting up from zero. The transportation costs in turn vary widely with system conditions -- supply and demand -- at all nodes on the network. In additional, generators can produce multiple services, consisting of both energy and various reserve services. So, the basic framework for thinking about competition among generators should be based on a fairly complicated spatial competition model with competing multiproduct firms at different locations which are "separated" by congestion costs and thermal losses. The suppliers of generation service are asymmetric, the costs of transportation vary widely over time as congestion varies, and the elasticity of supply around the competitive equilibrium varies widely over time as demand that must be met by just-in-time production fluctuates between very low and very high levels.

All of the credible models for creating new competitive electricity markets, recognize that there must be a single network operator responsible for controlling the physical operation of a control area, coordinating generator schedules, balancing loads and resources in real time, acquiring ancillary network support services required to maintain reliability and coordinating with neighboring control areas. In the U.S., there also seems to be general agreement that it would be desirable to consolidate the many control area that now exist into a smaller number of regional control areas to better internalize network externalities and to reduce transactions costs associated with buying and selling power over large geographic areas.

There is much less agreement about precisely what the network operator's role should be in organizing wholesale markets for energy and ancillary network support services, how congestion should be managed, the ownership structure for the network operator, and how the network operator should be regulated. The management of the interactions between the power markets and the operation of the network, and in particular the management of network congestion and reliability, are particularly challenging problems because of the existence of transmission constraints whose location and severity vary over time, potential network externalities arising from the interrelationships between generators and loads at different nodes on the network, and the need to balance supply and demand at every node on the system continuously to maintain the reliability and necessary physical operating parameters (e.g. voltage and frequency) of the network.

a. The Poolco vs. Bilateral Contracts Debate

The process that led to the restructuring of the power sector in California was characterized by a heated debate between what came to be called the "bilateral contracts" paradigm and the "poolco" or "nodal pricing" paradigm. This debate continues today as the wholesale market restructuring process proceeds across the country. The two approaches envision different roles for the network operator in creating and managing organized public markets for energy and ancillary services and different methods for managing scarce network transmission capacity (Joskow (1996)).

Under the bilateral contracts approach, the role of the network operator is conceived of as being limited and relatively passive. "Scheduling Coordinators" enter into contracts with generators to supply power and with customers or their agents to receive equivalent quantities of power from the network. Scheduling Coordinators are supposed to submit day ahead and hour-ahead schedules to the network operator that "balance" the generation supplies they have under contract (or own) and the expected aggregate hourly demands of the customers they have under contract to supply. Scheduling coordinators must also have "physical transmission rights" to use the portions of the network required to support their transactions (Tabors (1996)). These physical transmission rights, in turn, are associated with some measure of the physical capacity of the network to accommodate supply and demand at different points on the network under different supply and demand contingencies. The physical transmission rights can be traded and their market value defines the price of transmission service (Joskow and Tirole (2000), page 12). In reality, expected supply and expected demand cannot be balanced perfectly in real time and physical transmission rights cannot match actual network capacity perfectly due to real time demand fluctuations, equipment failures, and unanticipated network constraints. As a result, under the bilateral contracts model, the network operator still must stand ready to make up for any such imbalances that may occur in real time, maintain the physical integrity of the network, enforce transmission rights, manage conflicts between the exercise of rights to schedule generation and the actual capacity of the network to accommodate schedules, respond to emergencies, and run a settlements system to settle imbalances between the generation actually delivered in real time by each scheduling coordinator's supply resources and the actual real time consumption of each schedulating coordinators customers. Accordingly, the network operator must still play some role in the short term management of the network, must contract with at least some generators for various network support and reliability services and have adequate physical controls and communications links to respond to emergencies. This model assumes, however, that bilateral trading in power, balanced scheduling obligations, self-supply of operating reserves through bilateral trading, and trading of physical transmission rights will do most of the resource allocation work, with the network operator playing a residual "mopping up" role.

The poolco or nodal pricing framework envisions the network operator playing a much more active role in both the energy markets and the management of network congestion. It envisions the network operator managing bid-based forward and real time public markets for delivery of power at different locations to determine hourly market clearing day-ahead and real time prices at different locations. Simultaneously, the network operator manages network congestion based on the supply and demand bids at different locations submitted when the unconstrained “least cost” allocations cannot be realized as a result of network congestion. This is accomplished through the use of security constrained optimization algorithms that take the portfolio of supply and demand bids for each hour and find the lowest cost allocations, and associated clearing prices, that balances supply and demand at every node on the network given network operating constraints. In addition, the original poolco/nodal pricing proposals fully integrated the scheduling and pricing of ancillary network support services (e.g. operating reserves) with the scheduling and pricing of electric energy, applying overall optimization and opportunity cost pricing principles for these complementary services provided by generators.

A significant problem with the bilateral contracts/physical transmission rights approach is that there is no unambiguous way to define transmission capacity and associated property rights from one point on the network to another. Network capacity varies widely with system conditions and the capacity to transfer power across one interface depends on loads, generation, and power schedules elsewhere in the system. To avoid significant conflicts between rights defined over different interfaces on the network, physical transmission capacity must be defined conservatively for sets of "stressed" system conditions. As a result, there may be more capacity available for use than has been allocated during many hours. There may also be rights conflicts under certain system conditions when the capability of the network to accommodate schedules is less than the rights that have been allocated to use it. These problems are compounded in the presence of loop flow (Joskow and Tirole (2000)). To deal with this problem, both "firm" and "non-firm" rights can be defined. Power schedules that are supported by non-firm transmission rights are the first to be curtailed when the “deemed” physical capacity of the network is not sufficient to accommodate all schedules. Moreover, physical rights can be used to enhance electricity seller or buyer market power since they can be “withheld” from the market, effectively reducing the capacity of transmission networks (Joskow and Tirole (2000))

The poolco or nodal pricing approach, on the other hand, does not define "hard" <u>ex ante</u> physical transfer rights from one point to another on the network. Nor does it distinguish between "firm" and "non-firm" transmission rights. Instead, the network operator accepts supply bids from generators offering supplies in the spot market, or congestion reservation prices for generators or intermediaries submitting bilateral schedules, and uses this information to ration economically available transmission capacity when the schedules that would otherwise clear th\e energy market in the absence of constraints cannot all be accommodated due to congestion. The rationing is effectively accomplished by calculating a cost-minimizing security constrained dispatch based on the bids and reservation prices submitted by generation suppliers and demand-side reduction offers by customers, that yield prices and quantities at each node that is consistent with network constraints. The procurement and pricing of operating reserves can be readily incorporated in the security constrained optimization process based on supply and demand bids and technical constraints (e.g. ramp rates) faced by individual generating plants. This optimization process yields a shadow price and supply schedules at each node which reflect the general equilibrium marginal opportunity cost of generating a little more or less at each node given network constraints, supply and demand offers. The ex post derived transmission price for power physically flowing from one node to another is then the difference between the prices at each of the nodes taking all network interdependencies into account. These prices are paid indirectly by customers and generators that buy and sell in the spot market auctions run by the network operator as the difference between the prices paid at supply nodes and demand nodes by those suppliers that submit bids to the network operator and are dispatched by it and by those customers who buy at the nodal prices. This leaves the network operator with some congestion rent payments when the network is constrained and prices vary from one node to another.

Instead of physical transmission rights, the nodal pricing approach envisions the creation of tradable *financial* transmission congestion rights which would allow generators to hedge the variance in the transmission congestion charges by obtaining property rights to the congestion rents collected by the network operator (Hogan, (1992, 1993); Chao and Peck (1995); Joskow and Tirole (2000)). These are financial contracts rather than physical scheduling contracts which entitle the holders to a share of the congestion rents as “dividends” associated with the congestion rights that they hold. The poolco model can accommodate bilateral schedules by generators which do not want to participate in the organized wholesale markets, but these bilateral schedules would still be subject to congestion charges based on the network operator’s nodal pricing and congestion management protocols. Bilateral schedules can be accompanied by “adjustment bids” that can be used by the network operator to manage congestion economically. As a result, a bilateral schedule which desires to “run” under any circumstances is effectively a supply or demand bid with an infinite reservation price for being curtailed due to congestion.

As we shall see, the organization of the wholesale markets in California took some attributes from the bilateral contracts model and some from the poolco/nodal pricing model. At least some of the problems that it has experienced in 1998 and 1999 are a result of "mix and match" compromises and an associated list of market design flaws. The wholesale market institutions in PJM and New York, and the new arrangements proposed for New England, rely much more on the poolco/nodal pricing model with financial congestion rights, while making participation in the network operator's forward and real time markets voluntary and allowing bilateral schedules subject to congestion charges.

b. Horizontal Market Power Considerations

All of the restructuring proposals hope to encourage a competitive generation sector that is largely free from price and entry regulation. Accordingly, issues associated with diagnosing and mitigating horizontal market power at the generation level are attracting a lot of attention.

Concerns about horizontal market power were heightened among U.S. policymakers in part because of the experience gained from the restructuring of the electric power sector in England and Wales during the 1990s. Various studies have shown that there was a significant horizontal market power problem in England and Wales' wholesale generation market (Green and Newbery (1992); Newbery and Pollitt (1997); Wolfram (1999)). The market power problems in England and Wales are generally attributed to the decision of the Thatcher government to divide the old state-owned generating assets into only three private companies. Moreover, some generators have strategic locations on the grid and, from time to time, "must run for reliability". Naturally, when the generators know that they will be called to run by the network operator to maintain network reliability (almost) regardless of what they bid, they submit high bids. For example, generating stations at strategic locations on the grid in England and Wales charged prices six times higher than those of other generators before the regulator imposed a price ceiling on them (Office of Electricity Regulation, 1992). Bid caps or alternative contractual arrangements should be put in place to mitigate this kind of "local" market power.

Since the United States enters the restructuring process with a large number of companies with generating assets and active wholesale markets for electricity, the challenge of creating a competitive generation sector should be less daunting than in many other countries that have started the restructuring process with a single dominant generator.

Moreover, new CCGT technology is allowing generating plants to be built economically at relatively small scale and with much shorter planning and construction lead-times, so entry from independent producers should play an important role in disciplining pricing behavior by incumbents in the long run. Nevertheless, diagnosing horizontal market power associated with unregulated supplies of generation services must confront a number of significant analytical challenges (Borenstein et. al., 1996). It has long been recognized that an important factor in assessing horizontal market power at the generation level is the cost and availability of transmission capacity (Joskow and Schmalensee, 1983, ch. 12). The extent of congestion at points on a transmission network varies widely as supply and demand conditions change, both during a day and during a year, so that the relevant geographic markets change as well over time. Since electricity cannot be stored, considerable care must be taken in identifying what capacity is competitive under different supply and demand conditions. And if demand is very inelastic, market power could be a potential problem, absent entry constraints, even with a relatively large number of suppliers under certain demand and supply conditions (Borenstein and Bushnell, 1997).

Creating a reasonably competitive generation market is certainly an important policy goal. However, creating a <u>perfectly</u> competitive generation market is not a realistic goal. The spatial attributes of generation markets and changing network conditions virtually assure that generation markets will never be perfectly competitive under all system conditions. But the test for deregulation of prices and entry into generation should not be whether competition is perfect -- in the sense that prices must precisely equal marginal cost. If we applied such a test we would not have deregulated airlines, railroads, long distance telephone and many other industries. Clearly, policymakers will have to make some judgement about when there is enough competition so that any remaining costs of imperfect markets are less than the costs of continuing regulation.

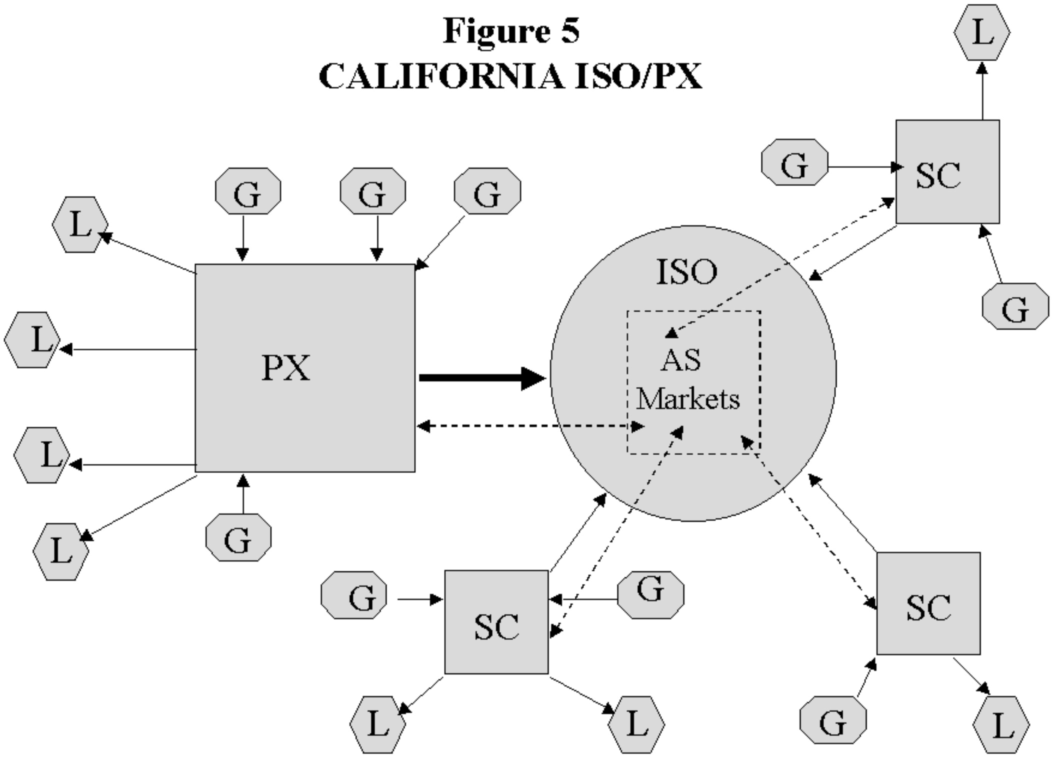
If or when significant horizontal market power problems are identified, two primary mechanisms are available for mitigation. One is to continue to subject incumbent generators to some type of price regulation. This may be a necessary solution to certain types of "local" market power problems where specific generators or groups of generators "must run for reliability." The second alternative is to require horizontal divestiture of generating facilities as a way of creating additional independent competitive suppliers. The extensive amount of generation divestiture discussed above, combined with the entry of new generating capacity, is doing exactly this.

TRANSMISSION AND WHOLESALE POWER MARKETS IN CALIFORNIA: AN EXAMPLE

A. The Structure of the California Wholesale Market

As I discussed earlier, California's restructuring program required the IOUs in California to create an Independent System Operator (CAISO)and a Power Exchange (PX), to turn the operation of their transmission networks over to CAISO, for the PX and CAISO to operate public markets with transparent market clearing prices for electric energy and operating reserves (ancillary services), and to manage congestion using market mechanisms. The institutional structure adopted by California is quite ambitious compared to the designs that characterize wholesale markets created earlier in England, Chile, and Argentina. It relies more on individual generator owners making decentralized unit commitment and dispatch decisions to supply energy and ancillary services and to manage congestion based on their own self-interests, and provides more bidding, dispatch and pricing flexibility than do most of the earlier organized electricity markets. The latter markets ultimately rely more on control by the network operator of generator commitment and dispatch once bids are submitted. It will be evident from the discussion of the California transmission and wholesale market institutions that creating competitive electricity markets is a fairly complex and challenging undertaking.

Figure 5
CALIFORNIA ISO/PX



The California ISO (CAISO): It will be useful to refer to Figure 5, which depicts the structure of the California wholesale electricity market institutions, to follow the rest of the discussion in this section. CAISO is the core institution that governs the operation of a large portion of the transmission system in California and the system's use as a platform for wholesale and retail market trading of electricity. CAISO is a non-profit public benefit corporation organized under the laws of California. However, it is subject to regulation by FERC under its rules governing transmission operators (Orders 888 and 889) as well as a set of "independence" criteria applicable to Independent System Operators. CAISO is responsible for operating the transmission networks owned by the three major investor-owned utilities in California,[57] is responsible for coordinating these operations with interconnected transmission systems in the Western System Coordinating Council (WSCC)[58] and operates a control center

[57] It was hoped that municipal transmission owners in California would also join CAISO, and that it would expand to include transmission owners in neighboring states. This has not yet happened.

[58] The WSCC is a regional reliability council that covers all of the states (roughly) west of the Rocky Mountains, western Canada, and portions of northern Mexico. Significant imports of energy into

to do so. CAISO has adopted protocols that allow generators directly connected to the transmission facilities it operates, as well as generators that can move their power over neighboring transmission systems to points of interconnection with CAISO's network, to be scheduled to serve demand (load) supplied over CAISO's network through intermediaries called Scheduling Coordinators (SC).

CAISO accepts hourly schedules from SCs on a day-ahead basis and an hour-ahead basis, and then manages the operation of the system in real time based on market information it receives from sellers and buyers and the physical constraints of the network. Demand and supply realized in real time can vary from day-ahead or hour-ahead schedules, and CAISO is responsible for balancing supply and demand in real time. To do so, it operates a real time energy balancing market into which generators can submit bids to supply more energy or to reduce the energy they have scheduled to supply to the network. CAISO also manages transmission congestion through its day-ahead scheduling process and in real time. To manage congestion economically, it relies on hourly adjustment bids and supplemental energy bids submitted by generators. When congestion arises, the marginal supply cost at different nodes on the network will vary (Joskow and Tirole (2000)). California has adopted a "zonal" congestion management system which allows separate market clearing energy and ancillary services prices to emerge in Northern and Southern California (separated by a transmission path called "path 15")[59] and at each point of interconnection between the CAISO's facilities and those of neighboring transmission operators.[60] (Different protocols are used to manage intra-zonal congestion, but I will not discuss these protocols here, except to note that managing intra-zonal congestion efficiently has become a significant challenge in California.) SC's scheduling supplies from one zone to another must make congestion payments to the ISO during periods of congestion. These payments are equal to the difference in the clearing prices, based on adjustment bids, on either side of any congested interface times the quantity being

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California and (less significant) exports of energy from California occur continuously. The volume and direction of trade varies widely with changing demand patterns in the WSCC and the availability of supplies from generating facilities, especially hydroelectric supplies.

[59] Early in 2000, California will create a third congestion zone that will be carved out of the current southern zone between path 15 and path 26.

[60] PJM and the New York ISO have implemented full nodal pricing systems. New York's wholesale market and congestion management system first became operational on November 17, 1999. The New England ISO also intends to implement a nodal pricing and congestion management system. These systems follow closely the nodal pricing models developed by Bill Hogan.

scheduled across it. These payments are then rebated to the entities that hold firm transmission rights on the congested paths.[61]

CAISO is also responsible for acquiring various operating reserve services ("ancillary services") from generators -- frequency regulation (also called Automatic Generator Control or AGC), spinning reserves, non-spinning reserves, and replacement reserves -- to respond to unanticipated changes in demand or plant outages in order to maintain the short term reliability of the network. It operates day-ahead and hour-ahead markets for each of these reserve services for each hour of the day. These markets select generators that agree to hold generating capacity with specified physical attributes (primarily adjustment speeds and communications capabilities) in reserve to be available in a particular hour to respond to instructions from the ISO to supply energy. Generators selected in these ancillary services auctions are paid a market-clearing reservation price to hold the capacity in reserve and are then paid for the energy they supply if subsequently called on by the ISO to supply energy.

When the wholesale market institutions were created in California, it was recognized that due to various network constraints, the ISO would have to rely on generators at specific locations on the network to operate under certain system conditions to maintain reliability. This led to concerns that when these generators expected that the ISO would have to call on them to maintain reliability, regardless of the prices they bid into the energy or reserve markets, they would have "local market power" and would charge very high prices to provide service at the direction of the ISO. Basically, network congestion sometimes effectively creates a geographic market for energy or ancillary services in which there is little or no competition. In order to mitigate these local market power problems, the ISO entered into contracts with these generators which specified a maximum price that they would be paid when the ISO had to call them "out of market" to meet reliability needs. Over 15,000 Mw of generating capacity, including a large fraction of the cycling capacity that is frequently at or near the margin on the supply curve where the energy and ancillary services markets clear, was eventually given the "reliability must-run" designation (RMR) and operated subject to these contracts.

Finally, the ISO is responsible for developing protocols for financial settlements between generators supplying to the network and agents for consumers using energy from the network, effectively determining energy and ancillary services imbalances and the associated financial responsibilities of each SC that schedules over the facilities operated by CAISO.

The California Power Exchange (PX): California's restructuring program created a separate "voluntary" public market for trading energy for each hour of the day on a day-ahead and hour-ahead basis.[62] This organization is the California "Power Exchange" or PX. The PX is a non-profit corporation organized under the laws of California and is also an SC for purposes of interacting with CAISO. Pursuant to California's restructuring legislation (AB 1890, passed in 1996), the IOUs in California must place all of the day-ahead demand from retail customers that have not chosen to be supplied by an ESP through the PX. They must also bid all of the energy supplied from any generating units they continue to own or power supplied to them under long term contracts into the PX as well. Other generators and other demand-serving entities (e.g. marketers, municipal utilities in California or utilities in other states) may voluntarily trade in the PX if they choose to do so. Market clearing prices, quantities and aggregate bid curves are publicly available for each hour of the day.

Other Scheduling Coordinators (SC): Energy marketers may register as SCs with CAISO. They must adhere to the ISO's operating and payment rules and meet credit requirements. An SC can organize its own portfolio of supply resources and load obligations and schedule its portfolio for physical delivery with CAISO. SCs rely on bilateral financial contracts with buyers and sellers (or owned-generation) to assemble their portfolios and are then supposed to submit balanced schedules (supply schedule = demand schedule) for each hour to the CAISO. The prices SCs pay to generation suppliers or charge to buyers and the methods they use to manage congestion are internal to each SC and such information is not public.

Market Operations: Let me focus on the day-ahead market which accounts for the vast bulk of the trade mediated by the PX and 80% to 90% of the energy traded over CAISO's facilities. The PX day-ahead market is a forward market that defines financial obligations of winning bidders. It does not determine physical delivery or consumption commitments, though the design of the PX/ISO/SC system is predicated on the assumption that winning generators scheduled through the day-ahead markets or self-scheduled by SCs

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[61] CAISO ran its first Firm Transmission Rights (FTR) auction during the week of November, 1999.

[62] The existence of a separate PX distinguishes the California structure from most other organized electricity markets. ISO-New England, PJM, and New York ISO operate both day-ahead energy and ancillary services markets. That is, there is no separate organized PX in these regions.

generally intend to supply energy during the indicated hours the following day. Early in the day before delivery, generators participating in the PX submit (upward sloping) supply portfolio bids (quantity and price schedules) to the PX for each (or any) hour of the following day. Distribution companies and wholesale market intermediaries also submit demand bids for each hour of the following day. The PX stacks up the supply-side and demand-side bids for each hour, identifies the highest bid that clears the market. This bid determines the day-ahead price at which the winning buyers and sellers are committed to trade during each hour of the following day. That is, the PX runs a uniform price auction for energy for each hour of the following day.

Figure 6 provides an example of what the aggregate day-ahead supply and demand bids and market clearing prices look like in the PX. Figure 6 reflects bids submitted to the PX on August 25 for supplies delivered during the hour beginning at 3 PM on August 26, 1998. The day-ahead market clearing price for that hour is just under $70/Mwh.[63] Once the winning bidders are chosen, the generators are required to provide the PX with information regarding which specific generators have been designated to meet their supply commitments, and the PX uses this information to develop a "preferred schedule" of specific generators and associated expected supplies for each hour of the following day. Generators also submit adjustment bids and ancillary service bids to the PX at this time, which indicate at what price they will increase or reduce their supplies.

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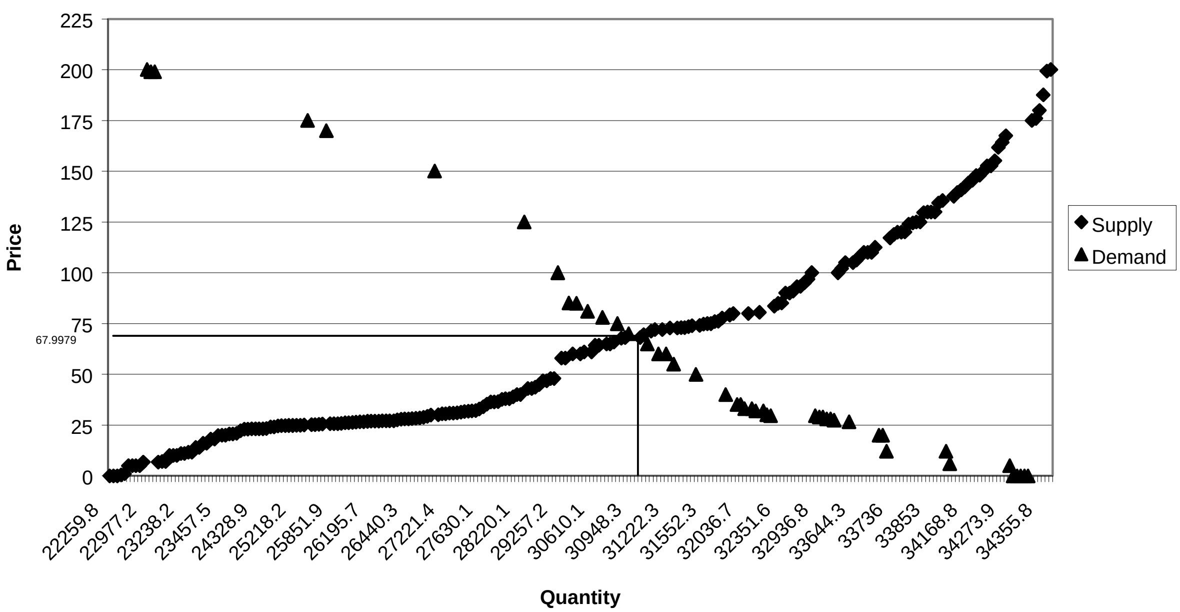
[63] Note that the slope of the aggregate demand curve reflects a day-ahead demand elasticity. Some of the apparent demand elasticity reflects demand that simply gets shifted to the real time market to take advantage of caps on real time prices. The rest is demand by utilities or marketers with generation portfolios who will supply from their own resources rather than buy from the market if the price gets high enough.

The PX then submits its preferred generation schedule for each hour of the following day to the ISO, along with generators' adjustment bids and ancillary services bids. The ISO also accepts preferred schedules from other SCs. It puts all of the preferred schedules together and determines whether the transmission network has the capacity to accommodate all of these schedules without creating interzonal congestion that must be managed. If the network has the capability to do so, then the ISO informs the SCs that their day-ahead energy schedules are accepted. The ISO also provides a preliminary schedule of, and prices for, ancillary services.

If expected interzonal network congestion makes it impossible for the ISO to accommodate both the PX's and other SCs' preferred schedules, the ISO informs them that anticipated congestion requires that the schedules be adjusted. The ISO provides SCs with a suggested set of schedule revisions based on adjustment bids they have submitted, as well as the associated congestion prices applicable to their interzonal schedules, and allows them to reschedule energy and ancillary services based on this information. The other SCs are free to resolve their congestion in any way they choose, including trading with one another. This

FIGURE 6
PX Aggregate Supply and Demand Bids, 8/26/98 3 P.M.



second set of schedules, and adjustment and ancillary services bids, are then resubmitted to the ISO by other SCs. The ISO then uses the adjustment bids that have been submitted to it by the PX to resolve inter-zonal congestion for its portfolio. If the ISO determines that the transmission network still cannot accommodate the adjusted schedules, the ISO applies its own schedule revisions to the other SCs' schedules based on adjustment bids that they have submitted to the ISO. [64]

This final step then leads the ISO to specify a final set of day-ahead schedules for energy and ancillary services, day-ahead ancillary service prices, and congestion charges for each hour of the following day. The PX posts a symmetrical set of zonal day-ahead prices for energy for each hour. To conclude the day-ahead scheduling process, the ISO determines whether there are any unmet local reliability needs and can then order schedule changes to meet them by calling on Reliability-Must-Run (RMR) generators with which it has contracts. (A similar process is used to adjust hour-ahead schedules, but the volumes in the hour-ahead (or day-of) markets are generally small and I will not attempt to run through these mechanisms here.)

This day-ahead bidding and scheduling process imposes financial obligations on sellers and buyers in the PX, not physical supply commitments. If the day-ahead market clearing price in the PX is $30/Mwh for an hour the following day, this is the price that generators which clear the day-ahead market will receive for the specified quantities and what buyers which clear the day-ahead market will pay for what they consume in that hour. If a generator does not deliver the quantity of energy that it has won in the day-ahead auction, other things equal, the PX will be unbalanced in real time. It will have to buy energy in the real time market managed by CAISO to make up the difference. The generator that fails to deliver energy to match its day-ahead commitments is then obligated to pay these charges. So, if the real time price is $50/Mwh, that is what the generator that has not delivered must pay for any supply shortfall. The real time price could also be less than $30. If a generator has won a forward supply contract at $30/Mwh and, as time progresses, concludes that the market may be soft and that prices will fall to a level below its marginal supply costs in real time, it may choose not to supply and pay the imbalance charges. A generator (or more precisely its SC) can implement this strategy by submitting schedule adjustment or supplemental energy bids to the ISO. It can also simply alter its schedule without instructions from the ISO, though wide use of this strategy can increase overall ancillary service and imbalance energy costs.

[64] However, CAISO is prohibited from affecting trades between the PX and SCs and must manage congestion so that each SC's schedules remain balanced. This and other strange restrictions that have been placed on CAISO were introduced when the dark side of the force captured the market design process during 1997.

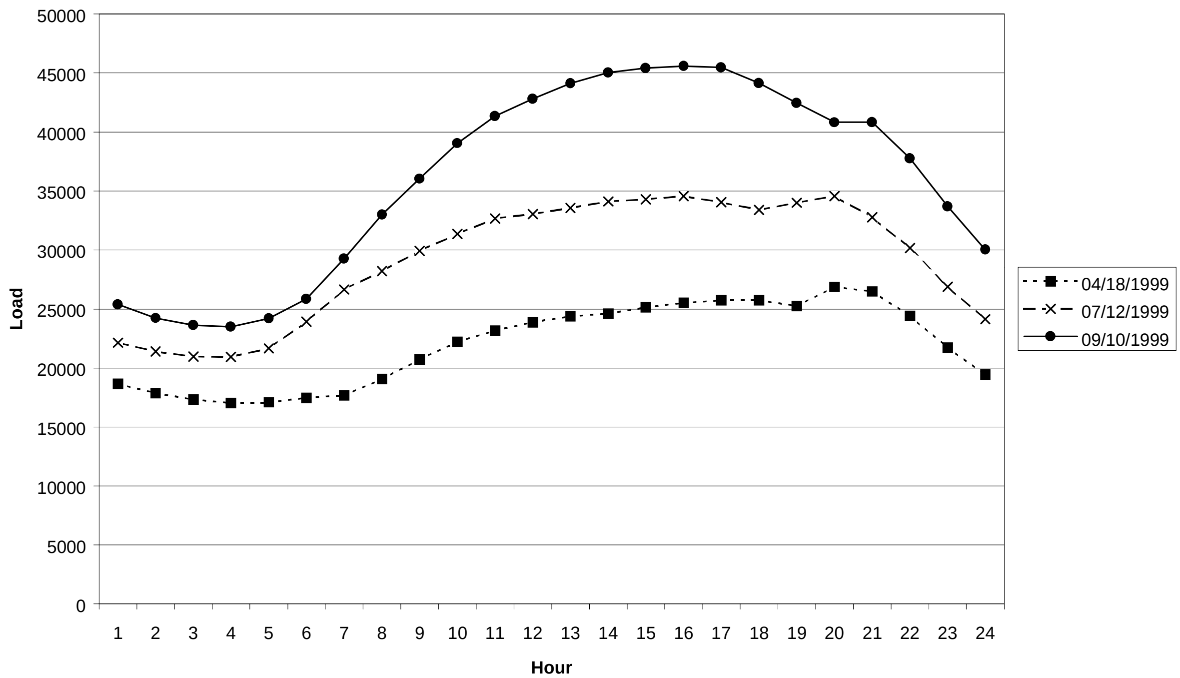
Transmission Pricing: The responsibility for paying for the sunk costs of the transmission network, and its operating and maintenance costs, is presently that of the distribution entities whose retail customers receive power over the ISO's facilities. These charges are included in each retail customer's base distribution charges as they have always been. These charges are known as "license plate" transmission charges since they give retail consumers or their agents (including the distribution company providing default service) access to any generator supplying to the market over the transmission facilities operated by CAISO. Existing generators in California, or generators located outside California that can deliver energy to a point of interconnection with the ISO, do not pay transmission service charges, unless there is congestion on a path over which their supplies are scheduled. When there is congestion, the SCs scheduling for the affected generators pay congestion charges day-ahead and/or in real-time. The congestion rents were initially rebated to the transmission owners and these revenues then reduce the transmission charges paid by retail consumers. The CAISO has created tradeable financial transmission rights (FTRs) which entitle the holders to a share of these transmission rents. The first vintage of FTRs was auctioned off during the week of November 15, 1999. The revenues from the auction will be credited back against the sunk costs of transmission and reduce the charges to retail consumers. (Interconnection of new generators and transmission expansion are controversial works in progress as this is written.)

B. Energy Market Behavior

The CAISO and CALPX began operating on April 1, 1998. Figure 7 provides information for the hourly loads served by the CAISO on three representative days: a relatively low demand day in April 1999, a moderate demand day in July 1999, and a high demand day in September 1999. As expected, demand is substantially higher during the day than at night, and a very high load day can have a peak demand that is almost double that on a low load day.[65] Figure 8 shows the associated day-ahead prices in the PX for each of the hours of the days reflected in Figure 7. To help to interpret the prices in Figure 8, Figure 9 displays a hypothetical short run marginal cost function (competitive supply curve) for energy that could be made available to the energy and ancillary services markets during an

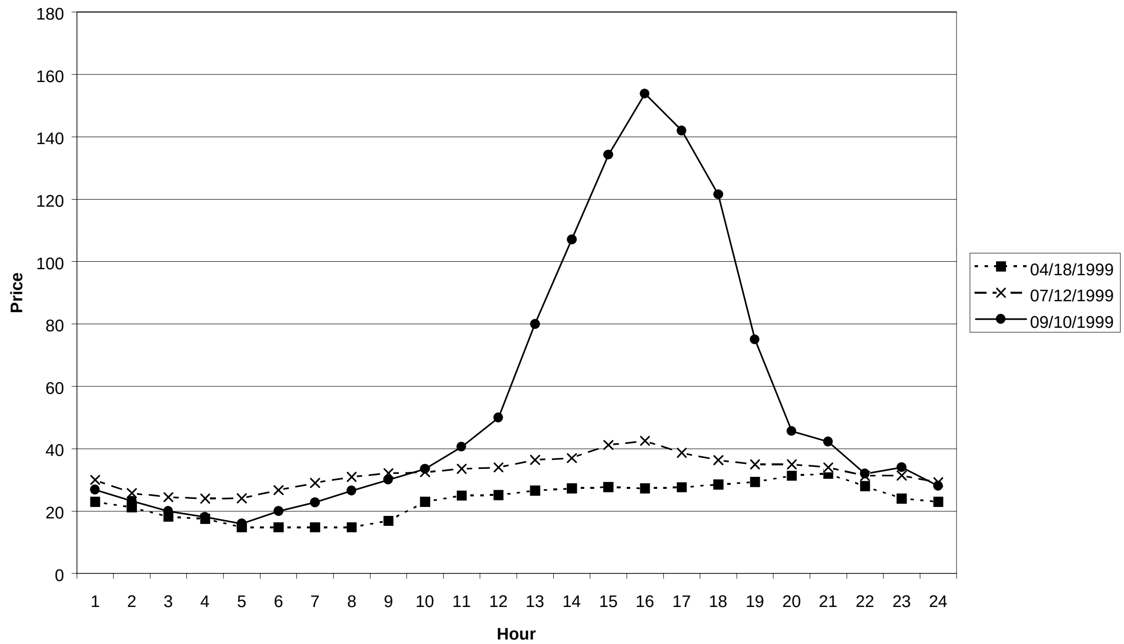
[65] In addition, demand is lower on weekends and holidays than on standard weekdays, other things equal.

FIGURE 7
ISO Load by Hour



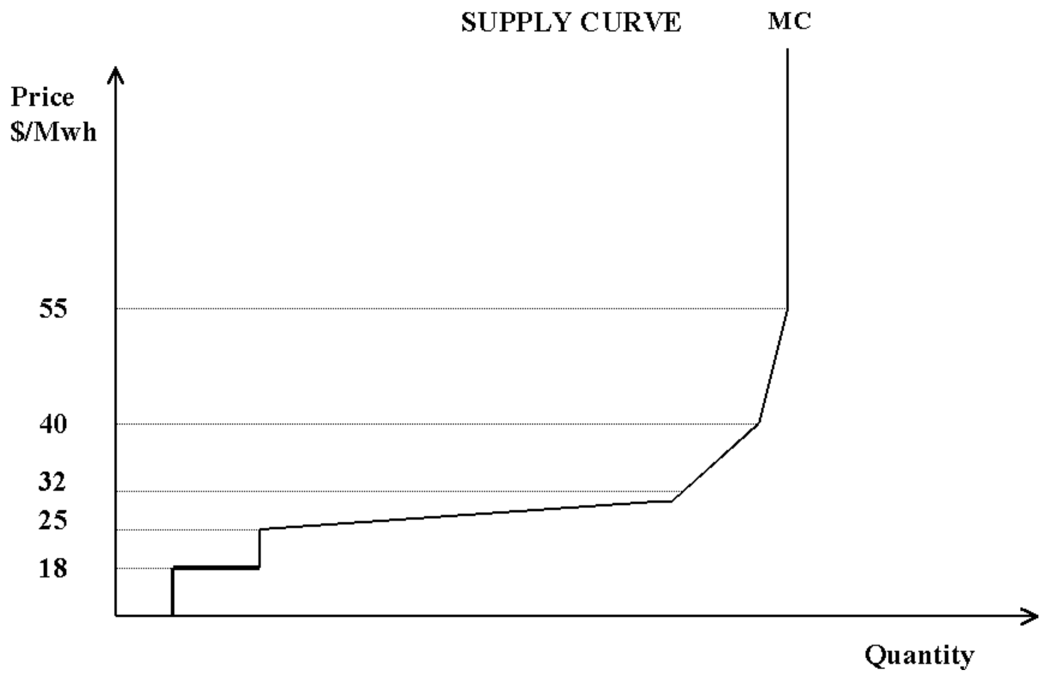
"average" hour. The marginal cost at very low demand levels can be as low as zero, especially during the hydro spill season in the late spring and early summer when there are abundant supplies of electricity. The relatively flat portion of the curve reflects generators with marginal supply costs in the \$25 to \$35/Mwh level. The inelastic portion of the curve reflects the marginal costs of operating peaking generators with a marginal supply cost in the \$35/Mwh to \$60 range, including start-up costs (Borenstein, Bushnell, and Wolak, 1999). At some point, capacity is exhausted and the supply curve becomes vertical.

FIGURE 8
PX Day Ahead Price by Hour



The hourly prices displayed in Figure 8 are higher in July than in April, reflecting the higher loads in July. The availability of more hydroelectric energy in early July increased supply and moderated the price differences. However, as you can see, the peak hour prices jump considerably during the high demand hours on September 10, 1999. This is far above the marginal supply cost of any generator in the WSCC. Indeed, the $250 price cap imposed by the ISO on real time prices (through September 30, 1999 when the price cap was raised to $750/Mwh) is effectively capping the prices in the day-ahead market as well during high demand conditions, since demand can arbitrage between the day-ahead and real-time markets with modest penalties.

FIGURE 9
COMPETITIVE ELECTRICITY
SUPPLY CURVE



Figures 10A through 10E provide scatter plots of market-clearing prices and quantities for the PX for all hours in the months of June through October 1998. Prices are relatively low in June, reflecting abundant hydroelectric supplies and low demand levels through most of the month. Demand increases later in the month as the temperature in California and the rest of the WSCC increases.[66] As a general matter, as the PX load goes above about 30,000 Mw (ISO load above about 40,000 Mw), PX day-ahead prices rise very quickly with small increases in demand. July, August, and the first week of September 1998 were very hot, and the demand for electricity in California and the rest of the WSCC hit new peaks. This is reflected in the very high clearing prices observed at high demand levels during these months. October is typically a low demand month due to moderate temperatures. It is also a time when generators begin to be taken down for maintenance, and the hydroelectric facilities in the Northwest

[66] Rising temperatures have two effects on demand and supply in the PX. Hot weather increases the demand for electricity in California, and this is reflected in the demand recorded in the PX. In addition, when it gets hot in California, it is likely to get hot in other areas of the WSCC (e.g. Phoenix). Generation supplies that might have bid into the California market are now utilized to meet demand in their local markets. This reduces the supplies available to serve demand in California at each price level and shifts the aggregate supply curve available to serve demand in California backwards. Unusually cold weather has similar effects on demand and supply in California.

import cheap energy at night through California to store water for use later in the winter. As you can see, prices at all demand levels are quite closely clustered in the \$20 - \$40 range in October 1998.

FIGURE 10A
PX UCMP vs PX Load -- JUNE

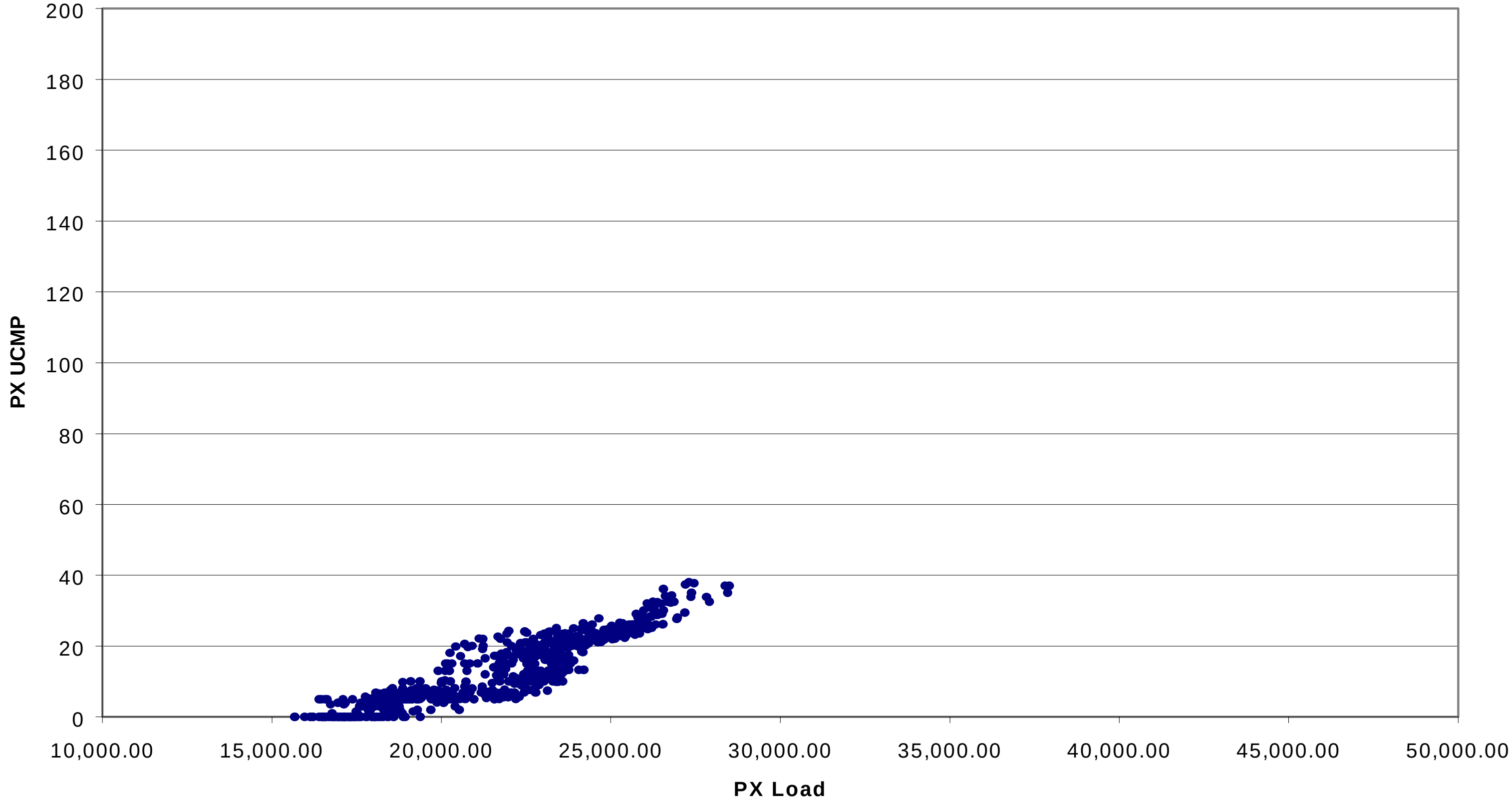


FIGURE 10B
PX UCMP vs PX Load -- JULY

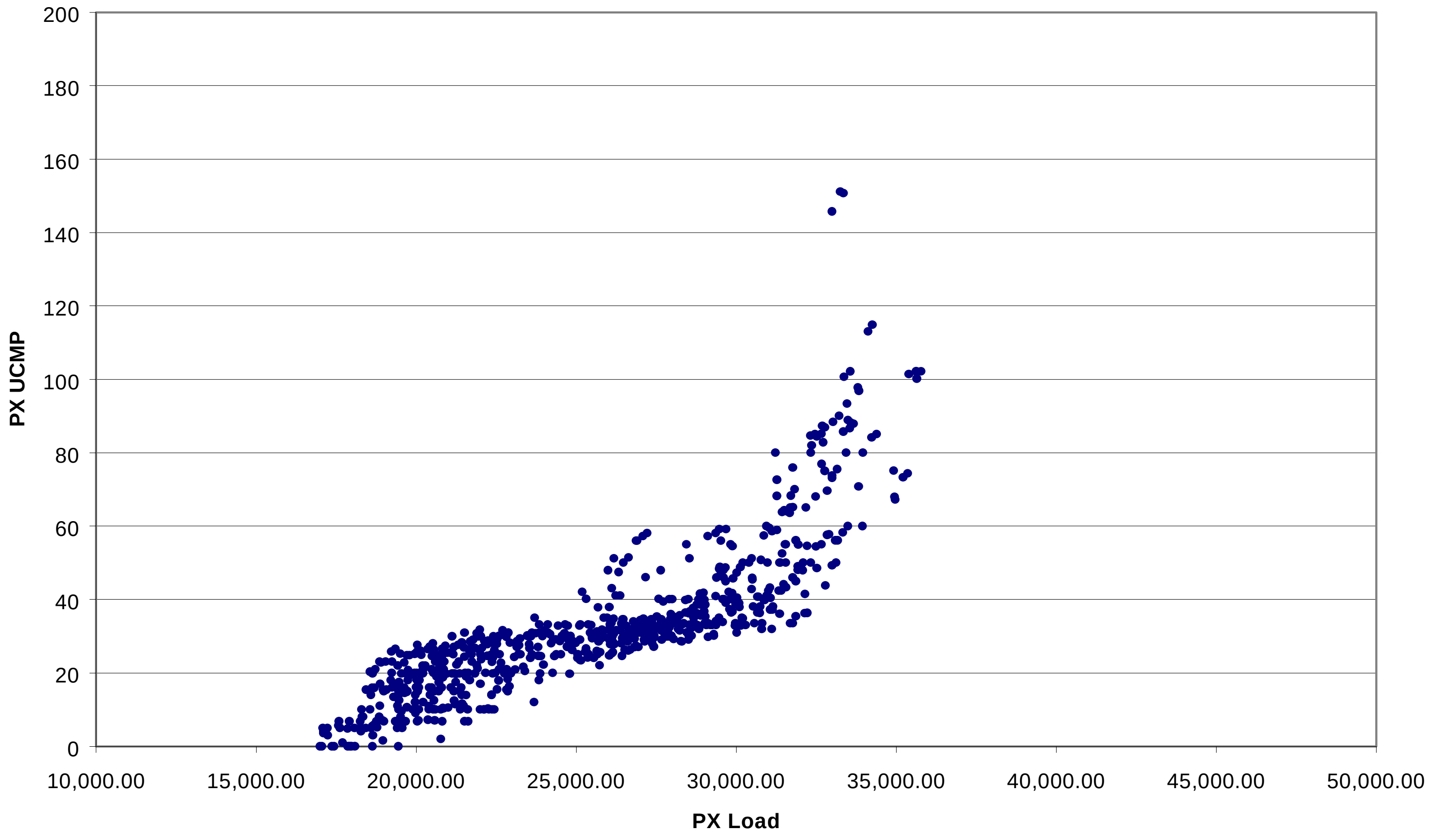


FIGURE 10C
PX UCMP vs PX Load -- AUGUST

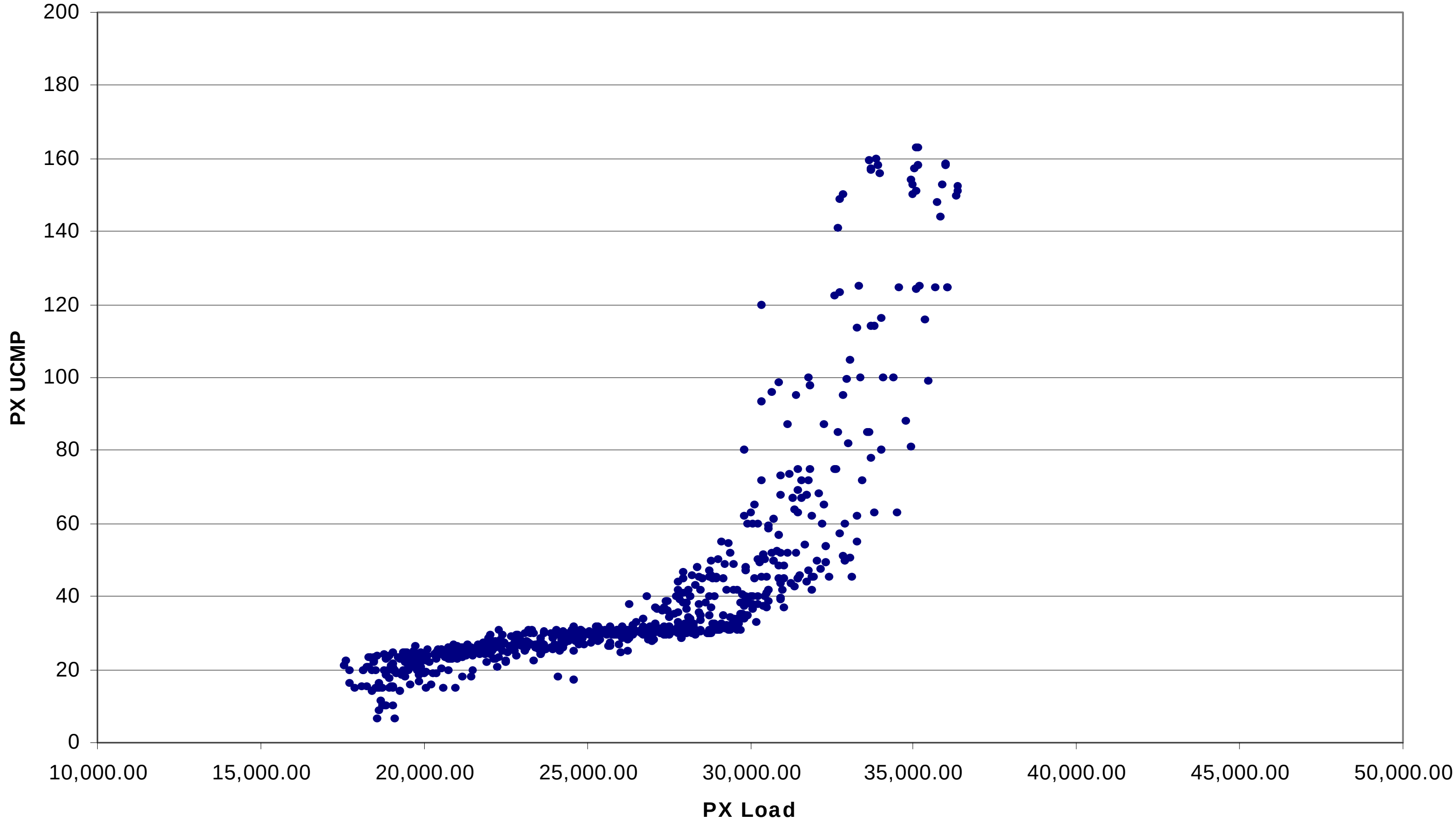


FIGURE 10D
PX UCMP vs PX Load -- SEPTEMBER

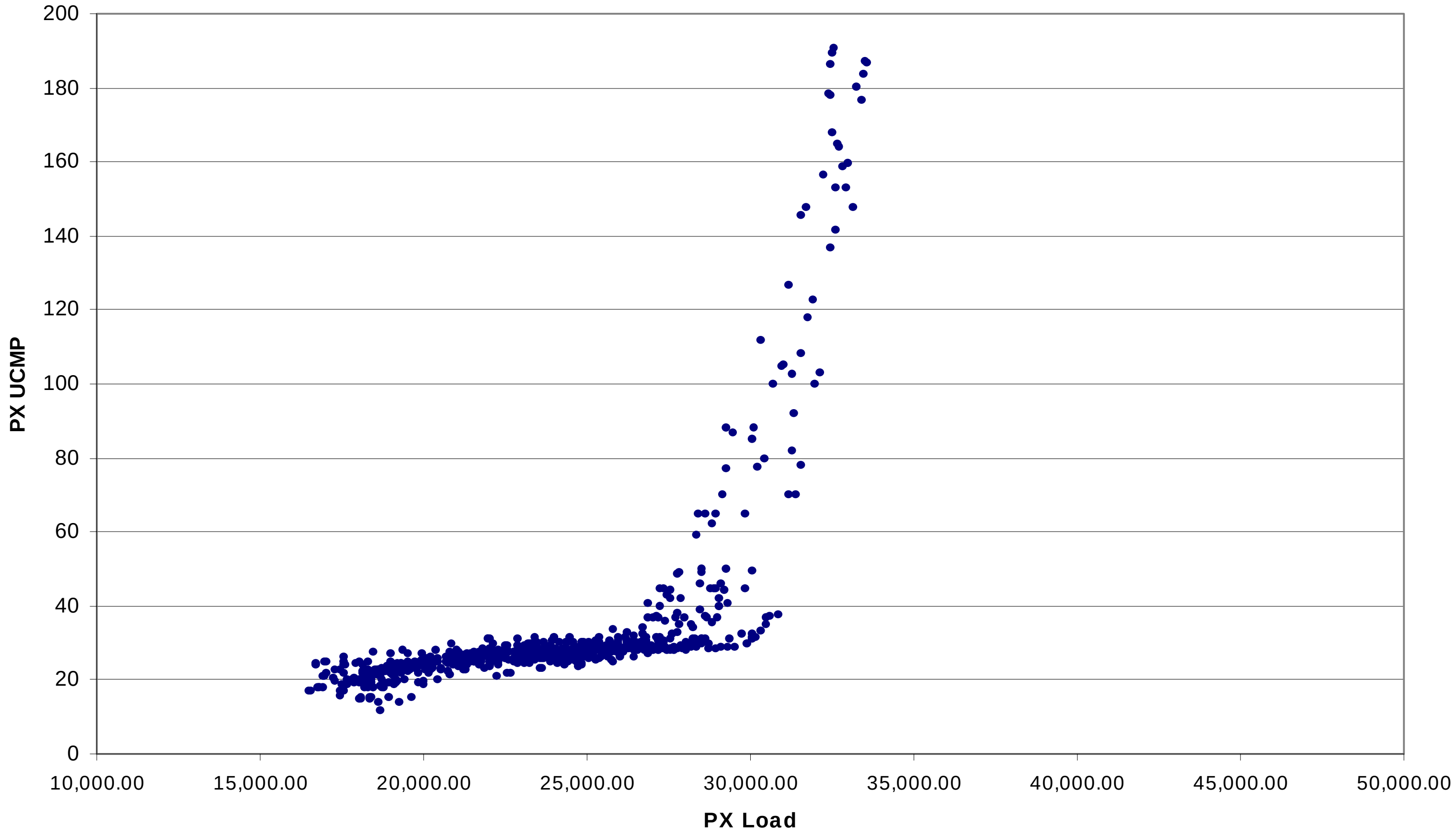


FIGURE 10E
PX UCMP vs PX Load -- OCTOBER

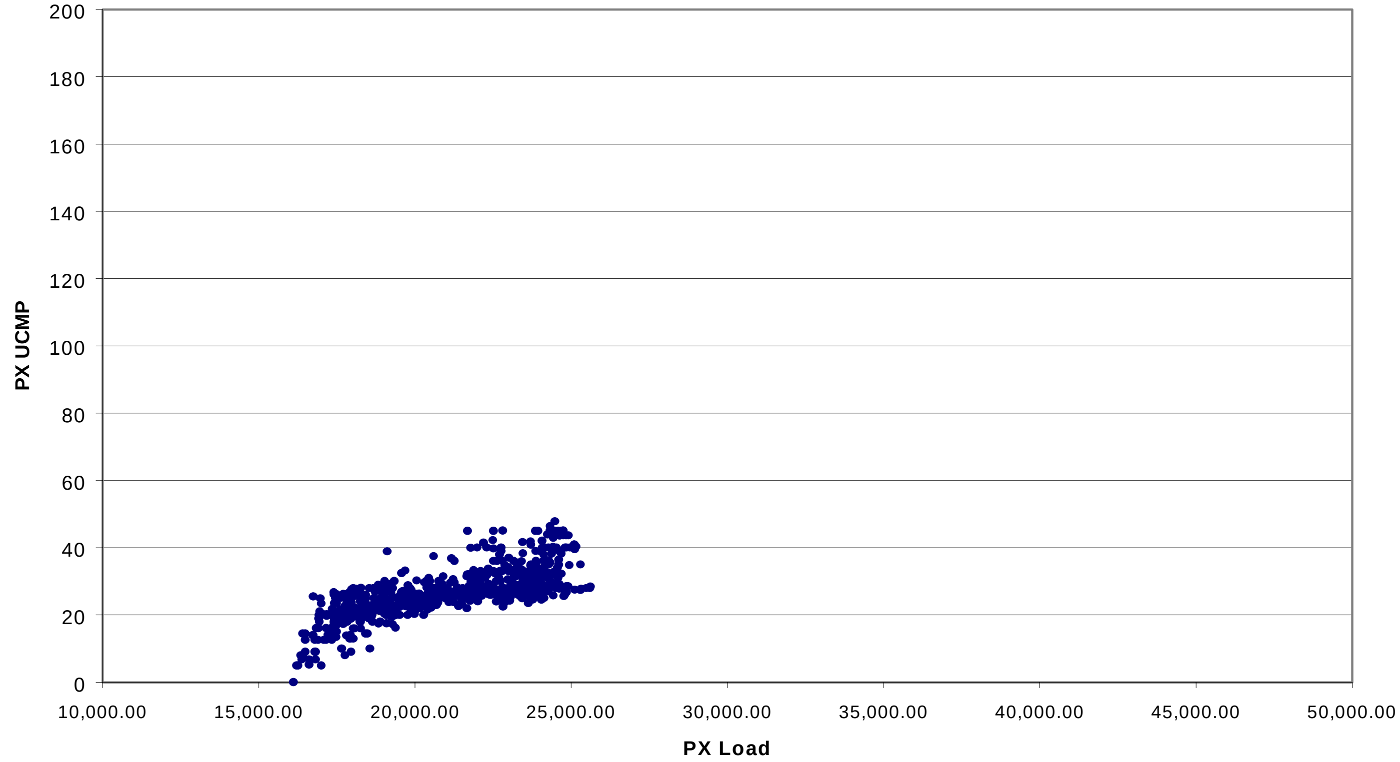


Table 8 displays day-ahead prices in the PX, the real time prices in the ISO, and prices for day-ahead bilateral contracts for energy sold in Southern California for the first 18 months of the operation of the California markets.[67] The monthly average prices are further broken down between peak (16 hours each day) and off-peak (8 hours each day) periods. The monthly patterns I described earlier can be seen in the data for the whole period. Prices are higher during the day than at night. Prices are generally higher during the summer than the spring, fall or winter months, though prices were very high in early October 1999 due to a late heat storm and the raising of the real time price cap from $250/Mwh to $750/Mwh. It appears that prices are lower during the summer of 1999 than the summer of 1998, and this seems to be the case even when we control for demand and fuel price variation.[68] The bilateral market prices (based on private surveys of traders) move roughly in step with the equivalent PX prices, suggesting that there is arbitrage between the PX and bilateral day-ahead markets, though the data for bilateral transactions are not good enough to draw more refined conclusions about the extent of price arbitrage. Similarly, real time energy prices move roughly with day ahead energy prices, though there appear to be systematic differences between day-ahead and real time prices, suggesting that price differences are not being fully arbitraged away.[69] Moreover, as expected, and not displayed here, real time prices are considerably more volatile than are day-ahead prices.

[67] The unconstrained PX clearing prices were obtained from the California Power Exchange's web site. The real time prices for the Southern Zone (SP15) were obtained from CAISO's web site. The bilateral contract prices for delivery in Southern California were obtained from Economic Insights, Inc. I am grateful to Economic Insights, Inc., for providing me with these data for the last few years.

[68]Based on preliminary econometric analysis of PX prices, which I am now completing.

[69] Real time prices appear to be systematically lower than day-ahead prices during the spring of 1998 and systematically higher than day-ahead prices during the summer of 1998. Price differences appear to be more fully arbitraged away since then, though this question is worthy of further analysis. See Borenstein, *et.al.* (1999).

TABLE 8
($/MWH)

Year	Month	Unconstrained PX Clearing Prices All hours	Peak	Offpeak	Bilateral Prices (SP15) All hours	Peak	Offpeak	ISO Real Time (SP15) Prices All hours	Peak	Offpeak
1998	4	22.60	25.24	17.33	20.15	25.11	15.19	20.30	23.30	14.27
		(23.32)	(25.59)	(17.89)						
	5	11.65	14.23	6.48	12.71	16.74	8.68	10.08	12.66	4.91
		(12.5)	(14.85)	(6.93)						
	6	12.09	15.39	5.50	10.65	15.49	5.81	8.38	10.35	4.45
		(13.26)	(16.26)	(6.06)						
	7	32.42	37.69	21.87	24.92	34.21	15.63	27.62	33.67	15.53
		(35.58)	(40.6)	(22.94)						
	8	39.53	46.72	25.14	35.26	45.70	24.81	43.53	53.41	23.75
		(43.42)	(50.37)	(25.72)						
	9	34.01	38.74	24.55	30.66	38.33	22.99	35.13	40.97	23.44
		(36.96)	(41.79)	(25.07)						
	10	26.65	29.00	21.94	22.77	26.52	19.02	27.66	31.80	19.41
		(27.28)	(29.35)	(22.31)						
	11	25.74	28.04	21.15	21.24	24.89	17.59	24.08	27.67	16.91
		(26.45)	(28.52)	(21.5)						
	12	29.13	31.25	24.89	21.74	24.98	18.49	26.13	29.41	19.59
		(29.98)	(31.94)	(25.41)						
1998 Total		26.01	29.63	18.78	21.28	26.28	16.29	24.81	29.30	15.83
		(28.53)	(32.15)	(19.72)						
1999	1	20.96	23.22	16.44	19.94	22.35	17.53	19.50	21.53	15.43
		(21.65)	(23.63)	(16.86)						
	2	19.03	21.20	14.68	17.39	20.41	14.36	18.98	21.39	14.15
		(19.59)	(21.49)	(14.99)						
	3	18.83	20.91	14.66	16.97	21.02	12.93	20.09	22.93	14.42
		(19.31)	(21.12)	(14.97)						
	4	24.01	26.33	19.38	21.71	26.14	16.93	25.42	28.02	20.19
		(24.67)	(26.68)	(19.87)						
	5	23.61	26.87	17.10	21.81	27.37	16.26	19.66	21.47	16.04
		(24.74)	(27.65)	(17.71)						
	6	23.52	28.01	14.55	19.48	28.32	10.65	21.87	26.16	13.28
		(25.76)	(29.87)	(15.6)						
	7	28.92	33.49	19.80	26.62	35.94	17.30	22.22	27.81	11.05
		(31.52)	(35.66)	(20.63)						
	8	32.31	37.11	22.72	28.29	36.15	20.44	34.47	41.43	20.56
		(34.71)	(39.02)	(23.44)						
	9	33.91	37.33	27.08	28.59	32.51	24.68	33.09	39.37	20.53
		(35.15)	(38.19)	(27.54)						
	10	47.56	53.33	36.02	36.16	40.45	31.67	42.50	49.08	29.39
		(49.01)	(54.23)	(36.43)						
	11	36.91	41.53	27.66	22.50	26.65	18.09	31.95	38.01	19.83
		(38.29)	(42.39)	(28.09)						
	12	29.66	31.47	26.05	26.37	30.26	22.48	32.01	33.21	29.61
		(30.17)	(31.83)	(26.34)						
1999 Total		28.23	31.68	21.31	23.70	28.91	18.42	26.87	30.92	18.75
		(30.04)	(33.25)	(22.15)						

(numbers in parentheses are volume weighted averages)

C. Short-Run Market Performance

The performance of California's electricity markets has been subject to extensive scrutiny because the institutional arrangements approved by FERC (wisely) included a requirement that the ISO create a Market Surveillance Committee (MSC) and that the PX create a Market Monitoring Committee (MMC). Both committees have independent members, primarily academic economists. They have issued several reports and produced several papers based, in part, on proprietary data available only to the PX and the ISO. In evaluating the performance of California's electricity markets we must recognize that these institutions have only been operating for less than two years and that numerous refinements have been introduced during this time period. It is too early to perform the kind of comprehensive assessment as, for example, has been completed by Newbery and Pollitt (1997) for England and Wales.

1. Horizontal Market Power: During the development of California's restructuring program in 1995 and 1996, there was considerable concern expressed about the ability of the three incumbent IOUs (Southern California Edison (SCE), Pacific Gas & Electric (PG&E), and San Diego Gas & Electric (SDG&E) to exercise market power as a result of their control over the bulk of the generating capacity in California (Borenstein and Bushnell). The IOUs eventually agreed to sell their fossil generating capacity to third parties. SCE divided its fossil generating capacity in California into four bundles and auctioned the capacity off to third parties in late 1997 and early 1998. All of these sales closed before the markets opened in April 1998. PG&E sold some capacity in late 1997, that closed in 1998, but the bulk of PG&E's and SDG&E's fossil capacity were auctioned in 1998 and the sales closed in 1999. The IOUs retain their nuclear capacity and contracts with QFs. PG&E had substantial hydroelectric capacity during the period covered by Table 8, though this capacity too is now up for sale. Nevertheless, there has been very significant deconcentration of ownership of generating capacity in California over the last couple of years, and there are substantial imports from generation suppliers outside of California. Moreover, the stranded cost recovery mechanisms created by the California legislature is, in effect, a contract for differences, which makes higher prices unprofitable for all three IOUs when they are net buyers of energy in the wholesale market.

During low and moderate demand conditions, the energy markets appear to be quite competitive, with day-ahead prices observed to be reasonably close to estimates of marginal cost. This is generally the case whether or not there is congestion observed on Path 15 or the ties with other systems.[70] When demand gets very high, however, it is clear that the market is clearing at prices far above the marginal cost of the most expensive generators in the region. Since there is virtually no real demand elasticity yet in these markets, it is evident that as demand grows and supply gets very tight, generators realize that a small amount of capacity withholding, even with moderate levels of concentration, can lead to large price increases. All of the studies that have been done indicate that during very high demand periods, unilateral behavior leads to prices that are significantly above competitive levels (ISO Annual Report, Borenstein, Bushnell and Wolak (1999), CAISO MSC Report, October 1999). The preferred long run solution is to bring more price sensitive demand directly into the day-ahead and real time markets by getting more customers on real time pricing programs, and to relax restrictions that are now placed on the California IOUs that limit their ability to enter into fixed-price forward contracts for energy months or years before delivery. The short run solution is to impose price caps on the real time markets operated by the ISO to keep the prices from running away to infinity. The ISO has had bid caps in effect on real time balancing energy since the markets began operating and imposed price caps on ancillary services markets in July 1998, when prices reached $10,000/Mw (ISO Annual Report, Chapter 3). These bid caps effectively cap day-ahead prices in the PX as well since buyers can submit price sensitive bids to the day-ahead market that effectively shift demand to the real time market when prices rise to levels approaching the caps.[71]

2. Ancillary Services Markets: In England and Wales and every other electricity market, besides the new U.S. markets, that I am familiar with, most ancillary services (e.g. spinning reserves and non-spinning reserves) are procured simultaneously with energy. Suppliers submit supply bids specifying prices and quantities at which they are willing to

[70] Congestion tends to occur in the North to South direction as a result of abundant suppliers of hydroelectric energy in the Northwest and Northern California in the Spring and early summer, when demand is relatively low. Congestion tends to occur in the South to North direction in the fall and winter at night when cheap energy from the Southwest is (effectively) being exported to the Northwest through California. The high priced periods in the summer of 1998 did not generally coincide with significant congestion. Demand was high everywhere in the WSCC, and there was little energy for export to California from the Northwest and Southwest.

[71] The PX itself has an administrative cap of $2500/Mwh. We have observed generators routinely placing bids into with PX with a small amount of capacity offered at $2500. The suppliers must be hoping that some demand-serving entities are not smart enough to arbitrage the cap on real time prices.

supply, along with relevant technical parameters for their generating units, and the network operator effectively does a simultaneous "least cost" procurement of energy and ancillary services. So, for example, assume that the expected system demand for an hour is 10,000Mw. Based on the supply bids submitted, the network operator would buy 10,000 Mw of energy and perhaps about 1,200 Mw of reserve services with the mix of response times and locations it requires to manage the reliability and power quality attributes of the network. To oversimplify a bit, the lowest bidders are selected to supply energy, the next lowest to supply frequency regulation (AGC), the next lowest to supply spinning reserve, and so on. These algorithms yield ancillary services prices that reflect simple opportunity cost principles. Ancillary services prices reflect the opportunity cost of a generator standing in reserve, rather than generating electricity, and generally decline with the "quality" of the service. For example, units selected to provide AGC may run, on average, at about 1.5% less than their optimal capacity as suppliers of energy. They would be paid the market clearing price minus their energy supply bids for this amount of reserve capacity. They would also be paid the market price for energy when they are dispatched by the ISO. Similarly, units that are providing spinning reserves are typically also supplying energy at a price very close to their bid price (they are typically close to top of the bid stack), and they would be paid their opportunity costs for the capacity that they make available for spinning reserves. This price is usually very low, since these units are the highest ones in the bid stacks. (Differences in physical capabilities of different generators complicates these pricing relationships, but I will not dwell on these complications here.) This integrated procurement approach seemed to work just fine in other organized markets, and indeed there is almost no mention of these reserve services in the literature discussing the markets in England and Wales, Argentina, and Chile, which have been fairly widely studied.

In Order 888, FERC decided that there would be four ancillary services that would be treated as separate products, and in the spirit of unbundling and relying on market mechanisms to allocate resources, decreed that there should be separate markets for these services. The California ISO set up separate day-ahead and hour-ahead markets for these services. These ancillary services markets have performed very poorly. Prices have been much higher than expected, and often bear no rational relationship between prices for different products and their relative quality (CAISO Annual Report, Chapter 3, CAISO MSC Report, October 1999). The combination of separate sequential markets and zero price elasticity of demand for ancillary services has exacerbated market power problems, especially since the supply of some of these services is highly concentrated during some system conditions (CAISO Annual Report, Chapter 3).[72] The problems are most severe during high demand periods and when there is congestion isolating Northern and Southern California[73] (CAISO MSC Report, October 1999).

It was widely agreed that these ancillary services markets in California had to be redesigned to reflect a "rational buyer" approach that allows the network operator to adjust its purchases of individual ancillary services, so that the ISO does not buy a "low quality" service when it can buy a "high quality" service at a lower price. Some reforms along these lines were made in mid-1999. The system would work better if ancillary services procurement was further integrated with the energy market.

A somewhat different problem is related to the *quantity* of reserve services that CAISO was procuring in the market during its first year of operation. One of the costs of vertical separation and reliance on competitive markets for generation services, especially the self-commitment and scheduling philosophy that characterizes the California market design, is that network operators are less certain about the supplies and the loads (but mostly the supplies) that they will have to balance in real time. Their response to these commitment uncertainties has been to operate the systems more conservatively by, among other things, purchasing unusually large quantities of ancillary services. This too has increased costs and further exacerbated performance failures in the ancillary services markets themselves. Part of these extra costs were due to the conservative behavior of network operators may be transitory, but some of them are simply a cost of moving from a vertically integrated system to a decentralized system.

The overall result is that ancillary services costs in California during 1998 were much higher than anyone had anticipated, rising to over 15% of total energy costs during the summer of 1998. However, ancillary service costs in California have declined significantly during 1999, and this may be the result of reforms made to ancillary service markets during 1999 (CAISO MSC Report, October 1999).

3. Local Market Power and the Reliability-Must-Run (RMR) Contracts

As noted above, during the development of the framework that would govern California's competitive electricity restructuring program it became evident that it would be

[72] In New England, the market rules for ancillary services have also distorted bidding behavior and led to unbounded prices (Cramton, 1999).

[73] Administrative limits have been placed on imports of some ancillary services from outside the ISO's network for technical reasons.

necessary to operate specific generating stations located at strategic locations on the network in order to provide so-called "local reliability services" under certain system conditions. These generators are referred to as “Reliability-Must-Run” or “RMR” generators in California. On the one hand, this situation raised the concern that these generators would have "local market power" under these conditions and, absent appropriate mitigation measures, would be able to charge prices significantly above competitive levels when they expected to be needed for local reliability purposes. For example, if a generator at a strategic location on the network knew that with high probability that it would have to be run for local reliability purposes the next day, the generator could submit a very high day-ahead bid to the PX, thus ensuring that it would fail to be selected by the PX in its day-ahead auction because its bid price was too high. It would then be called "out of market" anyway by the ISO to meet local reliability needs and receive its excessive bid price.[74] At least in the short run, a generator located at such a strategic position on the network could exact almost any price from the ISO that it sought to bid, since supplies from this specific generator, or a very small number of similarly situated generators, would be necessary to maintain local reliability. These excessive charges resulting from the generator’s locational market power would be reflected in higher prices paid by electricity consumers. In order to

One approach to mitigating local market power is to enter into contracts with the associated generators that specify the price they will be paid when the ISO must call them “out of market.” A contract with the two properties noted above would have a two-part compensation arrangement. The first part would be a “Fixed Option Payment” that does not vary with the RMR unit’s actual output. The second part would be a per MWh “call price” equal to the unit’s marginal generating cost (including, in principle, all legitimate opportunity costs that result from being called under the RMR contract by the ISO). This would compensate the RMR unit for the costs it incurs when it supplies energy or ancillary services in response to instructions from the ISO. The marginal opportunity cost-based per MWh call price assures that the RMR unit owner will have incentives to supply voluntarily to the market when the expected market-clearing price exceeds it marginal supply costs. This is the case because it will be more profitable for the RMR unit to supply voluntarily to the market

[74] An RMR unit controlled by a scheduling coordinator other than the PX could achieve the same result by simply not scheduling the RMR unit in the day-ahead scheduling sequence and waiting for it to be called by the ISO.

and receive the market-clearing price than either to bid a high price that does not clear the market or to withhold capacity from the market in order to get an out-of-market RMR call and be paid the contract call price. It is more profitable because the call price specified in the contract is equal to the unit's marginal supply cost which, in this example, is less than the market-clearing price.

When supply and demand conditions are such that the RMR unit's marginal supply costs exceed the market-clearing price and, as a result, it would not be expected to supply voluntarily to the market, the RMR unit will still be fully compensated for the costs that it incurs to respond to the ISO's instructions, because the contract call price includes these costs. If, in addition, the Fixed Option Payment is set at a level that covers the RMR unit's net incremental costs of remaining open and available to meet its RMR responsibilities, then it will be fully compensated for these additional costs of providing RMR services as well.

Unfortunately, the original RMR contracts put in place by the CAISO did not have these properties. Indeed, in the process of trying to mitigate the direct effect of local market power by capping the per MWh prices that would be paid to the RMR units when they were called by the ISO, the original RMR contracts caused costly distortions in the broader energy and ancillary services markets (Bushnell and Wolak (1999)). The problems were magnified by the very large fraction of cycling capacity that was covered by these contracts. One contract (generally referred to as Contract A) had call prices that were generally much higher than the generator's marginal supply costs. This gave the RMR generators incentives to withhold capacity from the day-ahead energy market when they expected to be called by the ISO for reliability. This behavior reduced supplies and increased day-ahead prices significantly during certain system conditions. A second contract (generally referred to as Contract B) had a call price that reflected the unit's marginal running costs, but also provided that 90% of the net revenues earned by the unit when it supplied voluntarily to the market be credited back against the high fixed cost payment specified in these contracts. For RMR owners that also owned non-RMR units, these provisions significantly reduced their incentives to bid their RMR units aggressively into the energy market, since they could keep only 10% of the net revenues. In this way, these contracts softened competition and led to higher prices.[75]

[75] There were a number of other problems associated with these contracts and they way supplies from the RMR units called under the contracts were integrated into the market. I will not discuss these issues here. See CAISO MSC Report, October 1999.

The original contracts were amended effective June 1, 1999, and now reflect the appropriate option contract structure that I discussed earlier. The level of the fixed option payments remain a matter of dispute as this is written.[76] It is too early to tell how these contracts have affected market behavior and performance since a number of other changes to the ancillary services markets went into effect during the summer of 1999 as well (CAISO MSC Report, October 1999). Moreover, the level of the fixed option payment has implications for CAISO's choice of alternatives to the current RMR units through its Local Area Reliability Services (LARS) solicitation process.

Let me emphasize that locational market power problems can arise on any electric power network; they are not unique to California and are probably more prevalent than has generally been assumed. Locational market power issues have been identified and mitigation mechanisms have been implemented by other ISOs which have been created in the U.S. in the last couple of years as well as in England and Wales. In light of the problems engendered by California's approach to local market power problems, it would be worthwhile to evaluate alternative mitigation mechanisms that have been used elsewhere.

4. Congestion Management: California's inter-zonal congestion management protocols appear to work reasonably well. During the first year of operation, day-ahead import congestion occurred at the California-Oregon border during 18% of the hours and (north to south) on Path 15 connecting Northern and Southern California about 14% of the hours. Import congestion occurred on other paths less than 10% of the hours.[77] Export congestion (generally south to north) occurred much less frequently and primarily during off-peak hours. Total congestion charges were about $35 million dollars during the system's first twelve months. (CAISO Annual Report, Chapter 5).[78]

The management of intra-zonal congestion is much less transparent and the costs difficult to calculate, since the ISO relies heavily on the RMR contracts to manage intrazonal

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[76] I submitted testimony in the FERC proceeding that will resolve this issue.

[77] A third zone will be added in 2000. It will lie in the northern area of what is now the southern zone between Path 15 and Path 26.

[78] The FTR auction conducted by the ISO during November, 1999 yielded revenues of $41 million for 14 month FTRs. This is consistent with the historical congestion revenue data. It appears that congestion costs increased in 1999, but I have not yet analyzed the 1999 congestion cost data.

congestion.[79] When units with RMR contracts are not available to mitigate intra-zonal congestion, significant gaming has been observed by generators at strategic locations. This is an area where the ISO's protocols require further refinement (CAISO MSC Report, October 1999).

5. Have Wholesale Prices and Costs Declined?: It is natural to ask whether the introduction of these new and complex institutional arrangements in California have led to lower wholesale market prices. In England and Wales, despite persistent market power problems, wholesale electricity prices have declined as the competitive wholesale market has matured over the last decade. Are we observing similar responses to the expansion of competitive opportunities in wholesale markets in California? This is a hard question to answer, since it is not clear what prices to compare "before and after" the introduction of the new market institutions in California. Moreover, hydroelectric supplies, gas prices, and demand have varied over time and new entrants have not yet completed any new generating plants. Nevertheless, its usefull to take a peak at the data that are available.

A bilateral contract market for day ahead deliveries has existed in the WSCC for many years and I have been collecting survey data for daily transactions in this market since 1996. Table 9 displays the average day-ahead peak period bilateral contract prices for deliveries to Southern California for the months of April through December for the years 1996 – 1999. The ISO/PX institutions began operating in April 1998, so we can compare prices across time. There does not appear to be any evidence that the new market arrangements have led to significant changes in wholesale prices. If anything, wholesale prices have increased since April 1998, though we must be cautious in drawing strong conclusions from these data since demand and supply conditions vary over time. Of course, demand has grown relatively rapidly and there are been no new entry of complete plants yet, so prices should be rising over time, other things equal.

When we take into account the very high ancillary services costs, the RMR contract costs, and the costs of creating and operating the ISO and the PX (several hundred million dollars so far), it would be hard to make a convincing case that California's new wholesale

[79] The ISO distinguishes between local market power problems handled with RMR contracts and the management of intra-zonal congestion when there are too few suppliers to get competitive adjustment bids. Conceptually, these problems appear to be effectively the same, though there may be differences in severity, duration, and predictability.

market institutions have, so far, led to lower wholesale power and transmission costs. The best that we can say so far about the performance of the system, and the system is still in its start-up and fine-tuning stage, is that the start-up costs and market inefficiencies associated with these new market arrangements are an investment that we hope will yield greater societal benefits in the longer run as competition affects the costs and performance of existing generating facilities, new merchant plants that enter the market, and as demand side innovations associated with retail competition are developed and diffuse.

TABLE 9

DAY-AHEAD BILATERIAL CONTRACT PRICES
Peak Period: Southern California Delivery
($/MWh)

Month	1996	1997	1998	1999
January	13.0	18.7	23.1	22.3
February	11.8	12.7	18.3	20.4
March	10.6	15.2	21.2	21.0
April	11.9	17.4	25.1	26.1
May	11.7	24.1	16.7	27.4
June	13.4	21.8	15.5	28.3
July	19.0	25.1	34.2	35.9
August	21.9	31.0	45.7	36.1
September	18.4	32.7	38.3	32.5
October	21.4	26.5	26.5	40.4
November	24.1	25.5	17.9	26.7
December	26.1	25.2	25.0	30.3
Unweighted Average	16.8	23.1	25.7	28.9

Source: Calculated from daily reports provided by Economic Insights, Inc. Does not include PX transanctions. PX became operational in April 1998.

RETAIL COMPETITION AND CUSTOMER CHOICE

A great deal of the popular discussion of electricity sector restructuring, competition and regulatory reform has focused on providing "customer choice" for all retail consumers -- small, medium or large. As noted above, customer choice or retail wheeling programs separate the distribution of electricity, which remains a regulated monopoly, from the financial arrangements for acquiring electric generation services in competitive wholesale markets and reselling these services to end-use retail consumers. Utility distribution companies (UDCs) provide the first service. Independent unregulated electricity retailers (ESPs) provide the second energy supply service, relying on the UDC's distribution facilities to physically deliver the electricity. ESPs need own no physical electricity production or distribution facilities. ESPs are primarily financial intermediaries which acquire electricity in the competitive wholesale market and resell it at retail to residential, commercial, and industrial consumers. ESPs may provide their own metering, billing and customer care services to serve their retail supply customers, may rely on the UDC to provide some or all of these services, or may outsource them to third parties. Customers who do not switch to an ESP can generally continue to be supplied with electric energy by the UDC --via a default or standard offer service option -- based on a regulated price. The performance of retail customer choice programs depends on the existence of competitive wholesale markets, the retailing costs associated with marketing and billing for electricity, customer switching costs, and the intensity of competition among retailers.

Retail competition programs must confront two sets of issues. First, the vast bulk of retail consumers of electricity are now billed based on meters that do not record hourly consumption and that are read monthly or semi-monthly. However, as we have seen, wholesale market prices vary widely from hour to hour. If an ESP serves customers without hourly meters, how are the ESP's financial obligations for energy and ancillary services purchased through the wholesale market to be determined? How are the ESPs' retail customers' consumption from the network to be matched up against supplies from generators with which they have power supply contracts? In the absence of hourly metering, financial settlements must depend on consumption estimation protocols -- called load profiling -- that take each retail customer's monthly meter readings and allocate them into consumption estimates for each hour in the previous month. These load profiles are estimated by placing hourly meters on samples of representative consumers, developing a profile of the proportion of their recorded monthly consumption that is concumed in each hour of the month, and then assuming that each individual consumer with similar characteristics has the same hourly consumption patterns as the sample group. All ESPs and distribution utilities providing default or standard offer service must agree to adhere to the same load profiling rules in order to assure that the aggregate energy consumed from the network is attributed to some responsible ESP or UDC, and that this consumption can be matched with supplies to the network from generators with which they have contracts or supplies they have acquired through anonymous spot market purchases. Obviously, this is not an ideal measurement situation. Individual consumers have no incentives to respond to hourly price signals. Moreover, the load profiling and settlements systems are costly and time consuming to implement effectively.

Second, it is important to step beyond the public rhetoric about retail competition and recognize that there is a simple and low-cost way to ensure that retail electricity consumers get the *price-related* benefits of spot market competition among generation suppliers. Retailing costs (metering, billing customer services, etc.) represent a very small part of the average customer's electricity bill -- less than 5% (Joskow (2000)). The physical attributes of the production and delivery of electricity makes it very easy for a distribution company to give all retail electricity consumers the equivalent of direct access to the wholesale spot market for electricity. All that is required is that their demands be registered by the UDC in an organized wholesale market and their metered consumption billed at the wholesale price plus losses and any associated retail service costs. Accordingly, the societal benefits of retail competition programs turn on the value-added services provided by ESPs to consumers over and above what can they can realize in a simple and inexpensive way through direct access to the wholesale market via their local UDC. The success of retail competition should be measured by the valued-added services it brings to the system, not by the fraction of customers who decide to buy from an ESP rather than buy directly in the wholesale market from their UDC.

A retail competition program must start by unbundling "competitive services" (generation service supplies and their associated costs) from "regulated monopoly services" (e.g. transmission, distribution, and designated stranded cost charges). In the old regime, the typical regulated bundled electricity price was built up from various cost elements as follows (simplifying somewhat):

$$P_T = C_g + C_T + C_D + C_{RCS} + DSM \quad = \text{ average UDC bundled price/kWh}$$

C_g: Average accounting cost of utility owned-generation + QF contract costs

C_T: Average accounting cost of transmission service

C_D: Average accounting cost of distribution service

C_{RCS}: Average accounting cost of retail customer services or "RCS" (e.g. billing and call centers)

DSM: Charges for energy efficiency and other "public benefit" (e.g. low-income) programs

As discussed earlier, state electricity restructuring programs do at least four things that affect these base regulated prices. First, they include a scheme to measure and collect allowed stranded costs. Second, they impose a mandatory price reduction for at least some groups of customers whether they choose a competitive retailer or not. Third, they develop an unbundled rate design that separates charges for services or payment obligations that all customers must pay regardless of who they choose as a retail electricity supplier (e.g. transmission and distribution services, energy efficiency subsidy payments), from services and costs that are open to competition (e.g. generation services). Finally, the distribution utility is required to offer a regulated default or standard offer option to allow customers who do not choose to turn to a competing ESP to continue to receive basic energy service from the UDC. So the post-restructuring prices faced by consumers have the following basic structure:

$P_{UDC} = S_g + C_T + C_D + (1\text{-}a)C_{RCS} + DSM$ = average regulated price for non-bypassable distribution services

$P_{DS} = P_{DG} + aC_{RCS}$ = UDC default service prices for competitive services or the "price to beat" for ESPs

$P_{UDC} + P_{DS} \leq P_T$ (reflecting the policy of assured price reductions for a large fraction of retail customers whether the choose an ESP or not)

where all of the definitions are as above and:

S_g: Stranded generation cost component

P_{DG}: Default or standard offer price for basic generation services

a : Fraction of retail service costs open to competition

From the perspective of an ESP competing primarily on the basis of the price of commodity electricity, the magnitude of the “price to beat” relative to its own costs of providing these services is of great importance.

Different states have taken alternative approaches to setting the relevant charges. For example, California’s laws effectively require that the default service price reflect a direct passthrough of the prices paid by the UDC to the PX and the ISO for energy purchased in these markets to supply default service customers (ancillary services and RMR costs are included in transmission charges and are paid by all customers) plus a small charge for avoidable RCS costs. The reasoning was that once the customers have paid for the stranded costs of the generating plants, they are entitled to get electricity at its competitive market value. Since the PX and ISO are competitive wholesale markets for electricity with transparent prices, they represent a natural benchmark for the competitive market value of electricity. Thus, to compete successfully based only on price, an ESP must be able profitably to beat the PX and ISO prices, something that is very difficult to do.

Another example is provided by Massachusetts. Massachusetts focused its attention on minimizing stranded cost obligations (by requiring complete divestiture of generating plants), providing utilities with a credible commitment that if they divested, they would recover any residual stranded costs; giving all customers significant immediate rate reductions (10% in 1998 and another 5% in 1999) off their total bills; and gradually providing consumers with incentives to shop for an ESP. It adopted a “standard offer” approach which set an eight year trajectory of values for P_{DG} that starts at an estimate of the annual wholesale market price in 1998 (2.8 cents/kWh) and then rises over time to levels that were anticipated to be above the wholesale market price (5.1 cents/kWh in 2004). The idea was that over time, the rising standard offer price would create more “margin” against which ESPs could easily compete to move consumers off of standard offer services. As it turned out, the initial value for P_{DG} was probably somewhat below the actual wholesale market prices in 1998 and 1999. In addition, the Massachusetts restructuring legislation prohibits unbundling of billing, customer service and other RCS services before 2001.

As a final example, Pennsylvania chose an approach that was focused much more on providing stranded cost recovery to utilities and creating good market opportunities for ESPs than on quickly reducing retail prices for all customers. The mandated retail rate reductions in Pennsylvania were much smaller than those in Massachusetts, Rhode Island and (for residential customers) California. The value of P_{DG} was set at a level significantly above the wholesale market value of electricity for some utilities in the state -- this is referred to as a “shopping credit.” The size of the premium varied from utility to utility reflecting differences in the magnitude of their stranded costs rather than the market value of wholesale power. Since the stranded cost component of the non-bypassable UDC charges in Pennsylvania was determined in an administrative proceeding rather than through market valuation of generating assets, one can view the premium above the wholesale market value of electricity included in P_{DG} as either representing a policy of putting some of each utility’s stranded costs out to be competed away by ESPs or as providing an opportunity for the utilities to earn more than 100% of their stranded costs if retail competition is not too intense and if a large fraction of the retail customers continue to take default service from the UDC at a price that exceeds its competitive market value.

Tables 10, 11 and 12 display information on the number of customers who have switched to ESPs in each of these states. It is evident from the data in these tables that customers in Pennsylvania have generally taken much greater advantage of the opportunity to reduce their rates by giving their business to ESPs than have customers in California and Massachusetts. It is also worth noting that in Pennsylvania, larger customers have been able to take much greater advantage of retail competition than have smaller customers, despite the large residential shopping credits in some areas. Moreover, in California and Massachusetts, where the default and standard offer service has provide little if any margin over the wholesale price, ESPs have still been able to attract a surprisingly large fraction of the largest customers. This suggests that ESPs can and do offer large customers value-added services in addition to providing them with commodity electricity they acquire in the wholesale market.

The shopping credits in Pennsylvania have clearly given residential customers greater incentives to switch to ESPs, though the vast majority have continued to take bundled service from their local UDC. The fact that more residential customers have switched in Pennsylvania does not necessarily imply that residential customers are better off than they would have been if the Pennsylvania regulators had required UDCs to offer *all* residential customers the opportunity to buy directly at the wholesale price as is the case in California or to buy under a default service option as in Massachusetts. Customers who have not switched are paying both stranded cost charges and a generation service price that is in excess of its wholesale market value. In Philadelphia, for example, the discount of the total UDC default rate offered by the most successful ESP is only about 0.5 cents/kWh, while the discount would be roughly 1.2 cents/kWh if all customers could buy at the wholesale market price as in California. Overall, the 10% to 15% rate cuts implemented in California and Massachusetts for *all* residential customers have conveyed much more significant benefits to these customers than has Pennsylvania where the largest customers have received most of the benefits of restructuring so far. The only real value added services that appear to be offered to residential customers are "green power" products. At present, the kind of real time metering and control service that would help to improve wholesale market performance is not a major sales theme for ESP sales to residential and small commercial customers.

TABLE 10

RETAIL CUSTOMER SWITCHING TO ESPs IN MASSACHUSETTS

As of November 1999
(Retail choice started 4/1/98)

	% of Retail Sales
Residential:	0.17%
Small Commercial:	1.7%
Medium Commercial:	5.0%
Large Commercial:	20.7%

Source**:** Division of Energy Resources, Commonwealth of Massachusetts, November, 1999.

TABLE 11

RETAIL CUSTOMER SWITCHING TO ESPs IN CALIFORNIA
As of December 15, 1999
(Retail choice started 4/1/98)

	% of Demand	**% of Customers**
RESIDENTIAL	2.0%	1.7%
COMMERCIAL		
< 20kW	4.2%	3.4%
20 < kW < 500	14.6%	6.5%
INDUSTRIAL		
> 500kW	32.0%	20.1%

Source**:** California Public Utilities Commission, Direct Access Reports, December 1999.

TABLE 12

CUSTOMERS SWITCHING TO ESPs IN PENNSYLVANIA
PERCENTAGE OF LOAD SERVED BY ESPs
As Of 1/7/2000
(Choice started 1/1/99)

COMPANY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL
PECO	17.5%	39.15%	58.7%
PP&L	2.8	33.3	42.1
GPU ENERGY	6.7	58.2	67.3
DUQUESNE	13.6	41.3	13.4
ALLEGHENY	1.5	20.1	21.1

Source: Pennsylvania Office of Consumer Advocate

ESPs are actively lobbying to increase the margins that they can receive from customers through either higher shopping credits or more aggressive unbundling of RCS services. Marketing, metering, billing, and customer services that ESPs would like to supply to small customers has turned out to be more expensive than many ESPs, and many regulators, had anticipated.[80] There are also significant costs associated with developing load profiling and settlements protocols to match up monthly metered consumption for individual consumers with wholesale market prices that vary hourly. Moreover, there is no evidence that ESPs are yet providing small customers with much if anything in the way of value added services (e.g. real time pricing) over and above what consumers will get by buying directly in the wholesale market through their UDC. The major value added services being offered to small customers are "green power" and bundling of electricity, gas, telephone, and internet services (one stop shopping). Overall, it is not at all obvious to me that there is any net social gain from retail competition for smaller customers without real time meters compared to a regime where they

[80] GPU's Pennsylvania subsidiaries were unable to get any bids to supply wholesale power and retail customer care services to a 20% cross-section of its default service customers at a price less than or equal to its shopping credit. "GPU Reports No Bidders in Auction of 20 Percent of its Electrical Customers in Pennsylvania," GPU Press Release, February, 2000.

are given direct access to the competitive wholesale market by their UDCs. Indeed, if the ESPs are successful in getting regulators to build more margin into default service prices (or imposing mandatory assignment of customers), residential and small commercial customers may be worse off than they would be if the UDC just gave them a simple straw to the market. This appears to be the conclusion that Oregon came to. It has made retail competition available to the large customers, but not to residential customers. Instead, it requires the UDC to offer residential customers a choice of three energy service options: one based on wholesale spot market purchases, one based on longer term wholesale market purchases, and one based on competitive procurement of "green" power. Perhaps new technologies will reduce the costs of marketing, billing, real time metering, and control for smaller customers in the future. ESPs will then be in a position to offer value added services to residential and small commercial consumers, so the option of buying from an ESP under appropriate terms and conditions should still be available to all retail consumers.[81]

The societal benefits of retail competition per se are more apparent so far for larger commercial and industrial customers than for residential and small commercial consumers. Successful ESPs are offering them a whole package of energy management and energy procurement services covering electricity, natural gas, on site generation, and price and weather risk hedging products. We can expect to see a growing fraction of larger customers switching to ESPs in states with retail competition programs, even in the absence of additional subsidies or incentives to switch provided by state regulators.

CONCLUSIONS

Electricity sector restructuring, regulatory reform and the diffusion of wholesale and retail competition is still a work-in-progress in the U.S. Federal laws and regulations have created the opportunity for states to restructure their electric power sectors and the role of wholesale and retail competition in it. A growing number of states are taking advantage of these opportunities, but the major reforms so far are concentrated in the Northeast, California, and Illinois where stranded cost recovery provided a useful lever to encourage otherwise reluctant utilities to cooperate with the restructuring and regulatory reform programs.

[81] For example, the internet is now being used to sell and bill for electricity sold by ESPs to residential consumers. See http://www.essential.com/ and http://www.utility.com/ if you live in Massachusetts or California. Perhaps some day internet technology will be capable of remote metering of real time use as well.

However, the creation of transmission and wholesale market institutions to govern efficiently fully competitive wholesale electricity markets has proven to be a significant challenge. The optimal design of energy market trading and settlement rules, market mechanisms for the acquisition of ancillary services, transmission pricing and congestion management, institutions governing the interconnection of new generators, and the expansion of the transmission network capacity all remain uncertain and controversial.

California's transmission and wholesale market institutions have encountered numerous problems. A large number of market design changes have been implemented or proposed to try to fix these market design imperfections. Indeed, the California ISO has filed roughly 25 amendments to its basic tariff with FERC during this period. Many of these amendments have been motivated by the need to remedy market design and performance problems. There is some evidence that the changes in market design and contractual arrangements are mitigating the performance problems and reducing the costs of operating these markets (CAISO MSC Report, October 1999). This is encouraging, but additional design changes are needed. The New England ISO experienced similar problems during its first year of operation and intends to implement major changes in market design and congestion management during the next year. The wholesale market and congestion management system implemented in PJM has had the smallest number of problems, largely because it is not very different from the power-pool dispatch and operating mechanisms that were used when PJM was a large traditional power pooling relying on central economic dispatch based on marginal cost pricing principles. The Midwest, a region of the country where wholesale competition has grown dramatically, but where transmission and wholesale market institutional reforms have been minimal, has experienced serious network operating problems during the last two summers and some incredibly high spot market prices. Efforts to resolve these problems are accelerating.

I am not surprised that creating fully competitive wholesale electricity markets to replace the short term dispatch, operating reserve, and network management activities that used to take place within vertically integrated firms or tight power pools has proven to be quite challenging. I previously indicated that I expected this to be the case (Joskow, 1997). Moreover, based on the experience in England and Wales, a market system which is now almost a decade old, we should have expected that it would not be easy to set up a system that worked fully satisfactorily on day one. The system in England and Wales has been plagued by market power problems (Wolfram, 1999) and these problems have surprisingly persisted despite substantial entry of new generators and divestiture of generating plants by the larger suppliers. [82] As recently as this past summer, controversy about unusual price spikes emerged despite the fact that the two original dominant generating firms are no longer dominant by conventional market share measures (Office of Gas and Electricity Markets, 1999). Indeed, the British government is now designing an entirely new set of market institutions to replace what has been in operation since 1990. (Whether these changes will lead these electricity markets to perform better or worse is uncertain.)

The performance problems experienced in California and New England have been more severe than was necessary for two primary reasons. First, many interest groups involved in designing transmission and market institutions refused to recognize that electricity and electric power networks have unusual characteristics that must be taken into account in designing basic wholesale market and transmission network management mechanisms. Sometimes it was ignorance, but more often it was private financial interests that were at work to steer design decisions in the wrong direction.

Second, policymakers failed to heed the well-known maxim that haste makes waste. The designers of both the California and New England systems were under tremendous pressure from impatient regulators, marketers and IPPs to get the new systems in operation quickly.[83] Some regulators found it hard to accept that creating a new market system on electric power networks was hard work, with design challenges that were not easy to resolve and software problems that always take longer and are much more costly than the software designers claim will be the case when they are hired. Both systems went into operation despite widely recognized design flaws and software problems (Cramton and Wilson, 1998). We should now recognize that once a market system begins operating, it can be difficult to change it, because there are private interests that profit from the design imperfections and that have a stake in keeping them in place. The saga of the RMR contracts in California is a case in point. Well over a year after the problems with these contracts were acknowledged, some reforms are still in dispute and unresolved (CAISO MSC Report, October 1999).

[82] There has also been substantial exit of older plants.

[83] The PJM system was largely designed by utilities to reform existing PJM institutions to conform to Order 888 and faced less pressure from regulators to get it into operation quickly. By taking the time to get it right PJM ended up getting a good system operating more quickly. The start of the new market system in New York was delayed several times due to software and market design problems, but began operating on November 18, 1999.

It is clear that designing good wholesale market and transmission institutions remains an intellectual challenge and an even bigger implementation challenge. Nevertheless, all things considered, these markets seem to work reasonably well during the vast majority of hours when demand is not too high and the network is reasonably unconstrained. Of course it is true that during these system conditions the market institutions don't have to work too hard to allocate resources reasonably efficiently. I remain optimistic that we can fix the most serious problems that have emerged when demand is high and network congestion is significant if regulators can come to understand the nature of the problems and have the patience to give the system operators the time to fix them and the tools to mitigate the adverse impacts of these problems on market participants while they are being fixed.

Many economists who became involved in designing and implementing new wholesale market and transmission institutions have naturally focused their attention on market power issues from the traditional perspectives of the analysis of market structure. Some have performed simulations of market behavior using simple oligopoly models parameterized to represent the electricity market being studied (e.g. Borenstein and Bushnell, Green and Newbery). One of the lessons that I have learned in the course of creating new electricity market and transmission institutions is that the microstructure of the market rules that govern energy and ancillary services markets and the management of congestion are at least as important for determining market performance as are traditional structural and behavioral considerations. Here the devil is truly in the details. What are the detailed rules of the auction mechanisms that govern markets for a set of substitute and complementary services supplied by competing generators?

The experience with organized electricity markets around the world indicates to me that there is a fundamental set of tradeoffs that must be confronted here. On the one hand, we would like to give suppliers and marketers as much flexibility as possible to express fully their particular cost and operating attributes within the context of market rules and timing that allows for efficient price discovery and for the market to reach an efficient equilibrium. On the other hand, the more flexibility that generators and marketers are given to submit and adjust bids and schedules and the more independent "products" for which separate markets are created (linked by arbitrage opportunities), the more opportunities we may be giving suppliers with some market power to engage in strategic behavior to exercise any market power they may possess. It is clearly a mistake to make market design decisions based on the assumption that short-term electricity markets are perfectly competitive. Network congestion, loop flow, reliability constraints, imperfect registration of demand in short-term markets, asymmetric suppliers, and other considerations suggests perfect competition is an unattainable goal.

That markets are imperfect and market and transmission institutions need continuing improvement does not mean that the effort to create competitive electricity is not socially worthwhile. There may be costs associated with imperfect electricity markets, but they must be weighed against the benefits associated with replacing the imperfect institution of regulated monopoly with market mechanisms. Since the public interest rationale for restructuring has been to benefit consumers, it is natural to ask the following question: are there any visible *consumer* benefits yet from restructuring, regulatory reform and deregulation of the U.S. electric power sector against which we can balance the set-up costs and market inefficiencies that have been experienced in California, New England, and elsewhere? This is perhaps on unfair question since the major reforms are so new, and start-up costs and problems were anticipated. Nevertheless, it is a question worth asking and reflecting upon and revisiting as time goes by.

One obvious potential benefit is associated with the retail price reductions that we have seen in Massachusetts, Rhode Island, California, and other states that have already implemented reforms. However, these price reductions are not, so far, the direct result of wholesale or retail competition. They are more properly attributed to regulatory and legal obligations placed on utilities to reduce prices in conjunction with the resolution of stranded cost obligations, securitization of stranded costs, and cost pressures created by the introduction of incentive regulation programs that place pressure on all utility costs. In theory, regulators and legislators could have accomplished the same result more directly through the regulatory and legislative process without going to the expense and trouble of creating institutions like CAISO and CALPX. In practice, without the threat of pending wholesale and retail competition and the potential loss of billions of dollars in above market strandable costs, it is unlikely that utilities would have been so receptive to these cost pressures. More importantly, the prospect of selling generating assets to third parties, which in turn could use them to produce electricity for sale in unregulated markets, helped to reduce the burden of stranded costs and support the price reductions that we have seen so far.

I also believe that larger electricity consumers are seeing benefits from retail competition in the growing number of states where it is available to them. While these benefits are hard to document, they appear to take the form of lower energy prices and better energy procurement and energy management services that the best ESPs are supplying to these consumers. I remain skeptical, however, that small residential customers without hourly meters will benefit directly from retail competition over and above the benefits that they can obtain by direct access to the wholesale market through their UDCs. I also am concerned that some smaller consumers may actually be harmed by retail competition because the large advertising, marketing, and billing costs that ESPs incur must eventually find their way into the prices that retail customers pay for service. Utilities spend little in the way of marketing and advertising, so these costs are a tiny component of regulated prices. Few ESPs are yet selling value added services to smaller customers that will compensate for these increased costs. Perhaps we should not be too impatient on this front either. However, I believe that the regulators and legislators in Oregon may have taken the most sensible approach to retail competition for residential consumers at this stage in its evolution.

It has been my view that the primary benefits of a well designed competitive electricity sector will come from better incentives to improve the operating performance of existing generators, through incentives to retire generators that cannot make a go of it from market sales revenues, through incentives to control construction and operating costs of new generators coming into the market, and through incentives for innovations in generating technology. The decision regulators made to use stranded cost recovery as a bargaining chip to induce utilities to divest their generating plants was, I believe, quite fortuitous. A large stock of unregulated merchant generating plants has been created almost instantly out of the existing fleet of regulated generators, and these generators are now the core of wholesale markets in the Northeast and California. Their owners now have high powered incentives to optimize performance. The effective demand placed in competitive wholesale markets grew dramatically as these generators were divested as well. Without these generation asset divestitures, the competitive merchant plant wholesale market would have grown much more slowly than it has in the last couple of years.

More importantly, we are seeing a flood of new entry of merchant plants with state-of-the-art generating technology and continuing improvements in the thermal efficiency and costs of new generators. The economic prospects for very small generating plants that can be located close to demand continues to improve as well. Several nuclear plants have been retired because they could not cover their going forward costs, and stranded cost recovery mechanisms have taken sunk costs out of the decision to continue to operate or close these plants. It is especially gratifying to see that the generation investment process has largely been depoliticized in most regions, though provisions contained in some proposed electricity sector restructuring legislation which would require suppliers to adhere to renewable energy portfolio standards are a cloud on the horizon. It is in the areas of improved performance of existing generating plants, retirement of uneconomic plants, entry of new generators, and technological change where we need to focus our attention as we look for the most significant benefits of competition. We will have to wait a few years to see these benefits realized and to begin to measure them.

Let me conclude with some thoughts on where this work-in-progress is going. It should be obvious that the most significant reforms have taken place in those areas of the country where high electricity prices were a significant political issue, stranded cost recovery was a bargaining chip, and there were some rents to be shared to support significant short-term retail price reductions. What about places like Kentucky, or Wyoming, Indiana, or Idaho where regulated generation costs are probably below their competitive market value?[84] How do we convince the people there that competition is good for them? I do not believe that in the long run the U.S. electric power sector can exist and prosper with a checkerboard of competitive and non-competitive states taking power from the same transmission networks, or even with a large number of competitive states which have adopted a wide array of different rules and institutions for wholesale and retail competition. On the other hand, it's not going to be easy to convince those folks in low-cost states to adopt fundamental reforms when they see all of the market performance problems in California and New England and no obvious benefits for their constituents.

It seems to me that there are two paths that this process may proceed down to bring the rest of the country into the competitive electricity market system. One approach would be for Congress to pass national legislation that effectively forces all states to adopt the full wholesale and retail competition model. The Telecommunications Policy Act of 1996 might be a model for this approach. Many electricity bills have been submitted to Congress in the last couple of

[84] Virginia is already confronting this problem. One of the utilities serving the western part of the state has regulated generation costs below the competitive market value of the generation service. Regulators have suggested that the utility issue credits to customers who choose an ESP. "AEP May Pay Va. Customers to Leave," *MegawattDaily*, November 16, 1999, page 1. The utility is not an enthusiastic supporter of this proposal.

years that are aimed at stimulating a more rapid movement in electricity restructuring among the states. Most of them increase federal authority to mandate regional transmission organizations and to deal with market power problems. Few, if any, of these bills, actually force states to adopt full competition models or require utilities to divest their generating plants. Moreover, the states seem to keep moving more quickly than Congress on the electricity competition front and FERC continues to use its existing authorities to move the ball forward. While I think that it is likely that electricity legislation will be a hot topic in Congress this, if for no other reason than it is good for campaign contributions, I doubt that any lergislation that is passed in the near future will *require* states to implement the kinds of retail competition and restructuring reforms that have been adopted in the Northeast and California.

In the end, I suspect that the electricity sectors in the low cost states will eventually migrate toward the full wholesale and retail competition model. I expect this to happen in the following way. First, utilities will effectively be forced by FERC and Federal legislation to create and join regional transmission organizations (RTOs) over the next few years. FERC is already moving in this direction and federal legislation is likely to speed this process. RTOs will either take a form similar to the existing ISOs, i.e., operating assets owned by vertically integrated utilities, or the RTOs will be created by utilities divesting and consolidating their transmission assets to form independent regional transmission companies (Transcos). Congress and FERC will make the second option more financially attractive than the first. Second, even in states that have not gone through comprehensive restructuring and have not yet made retail competition an option, new generating capacity is unlikely to be built by incumbent utilities under traditional cost of service principles. If utilities build new generating capacity they will be compensated for it based on market price indicia. Many utilities will choose to buy in the market under these conditions to serve their retail customers rather than to build themselves. This will support rapid continued growth of the merchant plant sector. Third, as utilities continue to merge or to seek regulatory authority to participate as unregulated sellers in wholesale and retail markets, they will face pressures from regulators and antitrust enforcers to divest some of their generating capacity to mitigate real or imagined horizontal market power problems. The utilities will be required to credit the bulk of any above net book value revenues back to retail customers in the form of lower *distribution* tariffs. They will be allowed to retain a share of the market over book value as an incentive. Fourth, wholesale market prices and regulated generation prices will begin to converge as utility-owned plants age and are retired, as utility-owned plants are divested, and as the typical utility's portfolio of generation resources contains more and more market-based supplies. Fifth, utilities will encourage their large industrial customers to shop directly in the wholesale market to avoid having to make further regulated supply commitments to serve them. This will bring things close to full convergence, but it will take five to ten years to get there.[85]

A potential cloud that I see on the long-term horizon is associated with the institutions that govern expansion of the transmission network, both to support more effective competition among existing generators as well as to support new entrants into the generation business to meet growing demand and to replace existing plants, often in new locations. The success of the ongoing restructuring of the nation's electricity sector and its reliance on decentralized competitive generation service markets depends heavily on the existence of a robust transmission network that operates efficiently. Indeed, the combination of the separation of generation from transmission (via divestiture and new entry of independent generators); the unbundling of generation services into multiple financial and physical energy, capacity, and ancillary service products; the entry of many new independent generation suppliers; the growing role of unregulated energy marketers; the rapid expansion of retail competition; and other changes in the structure of the industry, creates the need for a *more robust* transmission network and *enhanced operating capabilities* than was the case during the era of vertically integrated regulated monopolies. The recent historical evidence suggests that resources devoted to maintaining, operating, and expanding the nation's transmission networks are *declining* rather than increasing in relative terms.[86] This should not be surprising. Historically, major transmission enhancements generally accompanied the development of new generating resources by vertically integrated utilities (individually or cooperatively with their neighbors). Similarly, the maintenance and operation of transmission and generation were closely coordinated within individual vertically integrated firms or joint ventures in the form of tight power pools. We have destroyed the old institutions that supported transmission system maintenance and expansion decisions, but have yet to replace them with new ones that work well. This is an area that needs much more attention.

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[85] West Virginia's pending restructuring plan has a 13-year transition period!

[86] Eric Hirst, Brendan Kirby and Stan Hadley, "Generation and Transmission Adequacy in A Restructuring US Electricity Industry," pages 4-5, June 1999.

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