Rethinking Electricity Deregulation

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Proponents of free markets for electricity assert that minor fixes to the California market and to FERC's standard market design (SMD) would generate lower prices. We disagree. Designing a competitive market that remedies the problems seen in California and other restructured markets is difficult; emulating even good ISOs like PJM will not do the job. Each one of the problems can be overcome, but the costs of doing so might make full deregulation unattractive.

I. Introduction

California's deregulated electricity industry was an experiment gone horribly wrong, costing more than $50 billion. Deregulation proponents argue (1) that the California market design was flawed in ways that were recognized at its inception, (2) that properly functioning electricity markets, such as the Pennsylvania-New Jersey-Maryland market (PJM) have already brought benefits to consumers through lower prices,[1] and conclude (3) that modest modifications in FERC's standard market design (SMD) would generate lower prices and other benefits, even for "hopeless" cases such as California.

We disagree. Designing a competitive market that remedies the problems seen in California and other restructured markets is difficult; emulating PJM will not do the job. We think that each one of the problems can be overcome, but the costs of doing so might make full deregulation unattractive.

In our judgment, implementing the PJM market design is unlikely to reduce <u>cost</u>, at least for the next few years. Regulators could mandate lower <u>prices</u> temporarily, but prices would have to increase to give utility investors an adequate return. Furthermore, SMD is likely to lower reliability and power quality. Companies are struggling with important problems, including attracting investment for generation and transmission. Failure to solve the problems will doom restructuring. Whether a competitive market for generation, one where each generator views herself as a "price taker" not a "price setter," could be created at reasonable cost is not yet clear. Finally, whether the benefits of a free competitive market would be worth the cost of setting it up is unclear.

Figure 1 shows how retail prices have reacted to market-based wholesale pricing in a number of regions. The restructuring in the late 1990s appears to have had no effect on prices beyond temporary mandated residential price reductions, many of which will expire soon.[2] Maine's prices declined because of two new natural gas pipelines; several states (notably Rhode Island and Massachusetts) are dependent on natural gas and so their prices reflect the gas pricing bubble between 2000 and 2002.
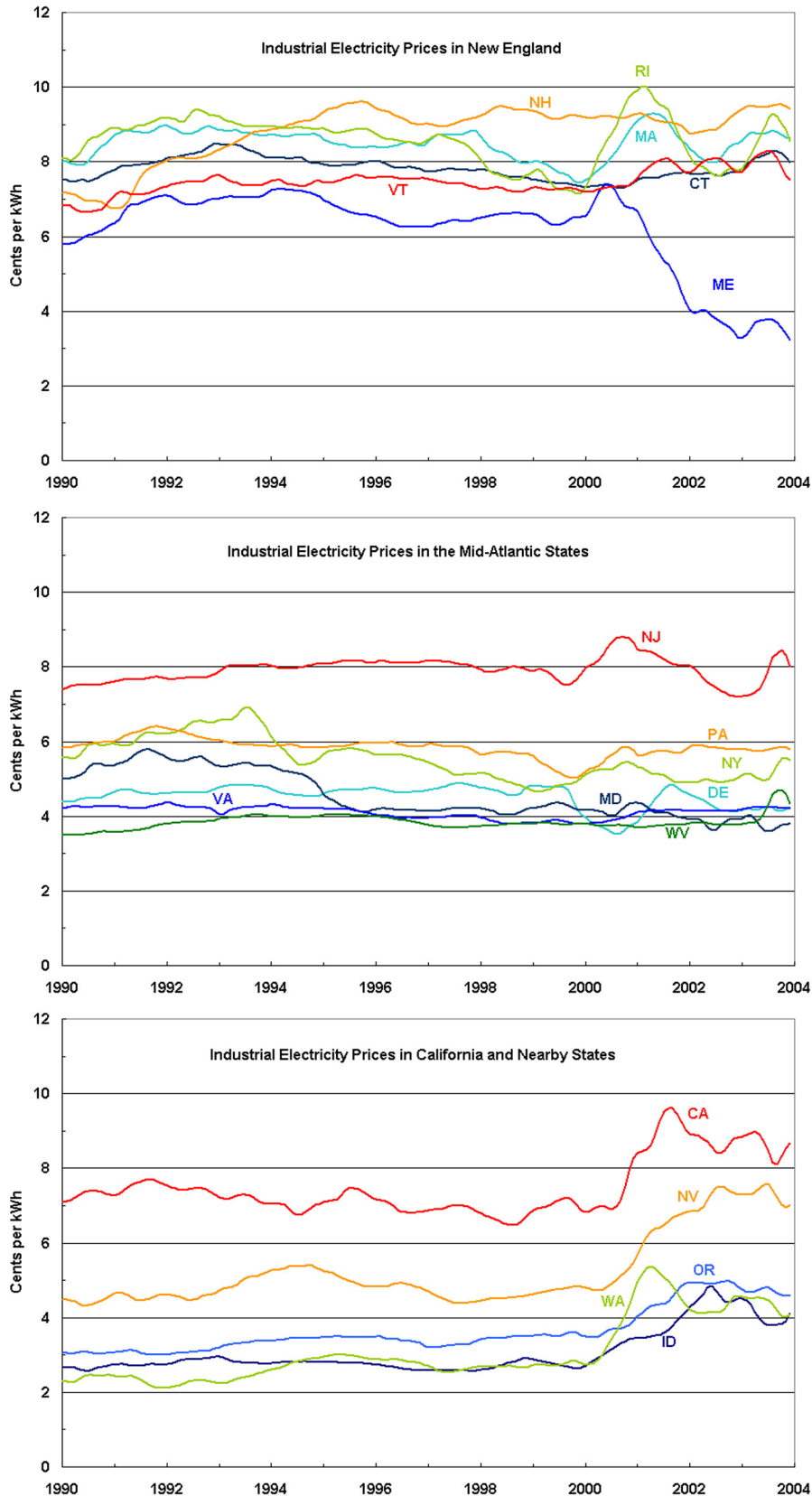
Figure 1: Industrial electricity prices in New England, the mid-Atlantic states, and the West Coast for 1990-2003.[3] In New England, only Vermont is regulated. The drop in Maine's prices reflects the completion of two natural gas pipelines from Canada. Rhode Island and Massachusetts generate much of their electricity from natural gas, whose price at the Henry Hub rose from $2.25/mmBtu in 1999 to $4.35 in 2000 before declining to $3 in 2002. In the western graph, California and Oregon were the only restructured states.

Many policy makers have little appetite for going back to the old regulatory system and vast reluctance to try new free market designs that might increase price or lower reliability. Public policy toward electricity is like a deer frozen in the headlights: The system is stuck with neither innovation nor the ability to go forward or backward. It is time to rethink SMD and deregulation more generally.

To explore these issues, we begin with a brief history of electricity supply in the United States, the rationale for the deregulation movement of the 1990s, and some of the economic issues involved. Then we examine the reasons for regulation, the problems that developed, and the inherent difficulties of creating a free, competitive market for generation. We propose solutions to each problem; the difficulty and cost of implementing these solutions could make market restructuring unattractive.

II. The Structure and Virtues of Free Competitive Markets

Economists extol the many virtues of free, competitive markets, assuming reasonably informed buyers and sellers and little fraud. When this sort of market can be created, it brings low prices and services that are responsive to consumer demands. Describing a market as "free" and "competitive" is not redundant. Economists warn that when a market where one or more sellers have market power is freed of regulation, prices are likely to rise far above marginal cost and other problems will occur.

The electricity market in the USA began as a free market in the 1880s. Within 25 years, suppliers pleaded for regulation, arguing that they faced "ruinous" competition. The public was not served well either. Writing for New York's Public Service Commission in 1908, Commissioner Maltbie stated

> "The whole electric history of New York points [out] the futility of competition…It is coming to be generally recognized that monopoly control of electric light, heat and power may be very beneficial to the public if one company or the few non-competing companies can be placed under such public regulation and control as will secure for the public a fair share in the many benefits arising from unified management. That competition cannot be depended upon to protect the consumer from high prices and poor service has been fully demonstrated.[4]"

A consensus soon emerged that vertically-integrated companies should be granted monopoly status within a geographical area in exchange for regulation that obliged them to serve consumers at low prices but gave them essentially guaranteed rates of return that could attract capital.

This system thrived in the USA until 1970, when real electricity prices began to rise. Figures 2 and 3 show the average residential electricity price in current and 2002 dollars, respectively, over a century. The price decline during the first years is impressive. After 1970, a combination of factors contributed to rising prices, which ultimately led to the deregulation movement in the 1990s. Many utilities had made unfortunate investments resulting in high costs, especially for nuclear plants, and were unable to operate the new plants efficiently. Consumers protested that they should not have to pay for bad investment.
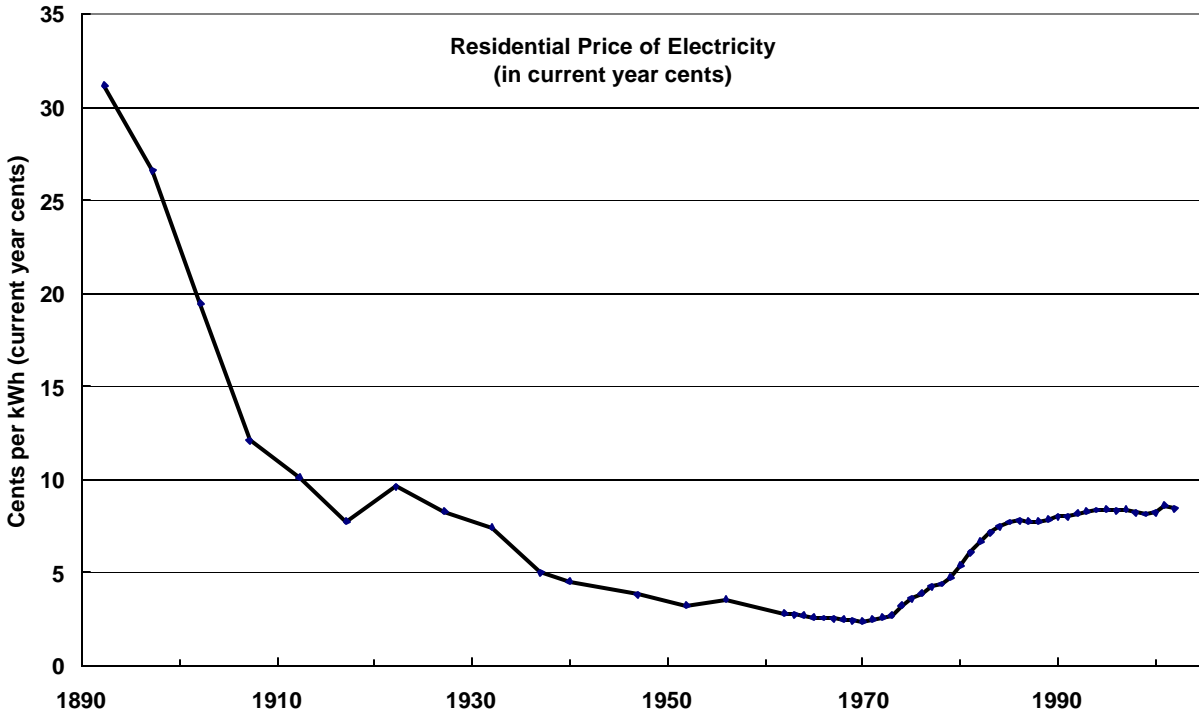
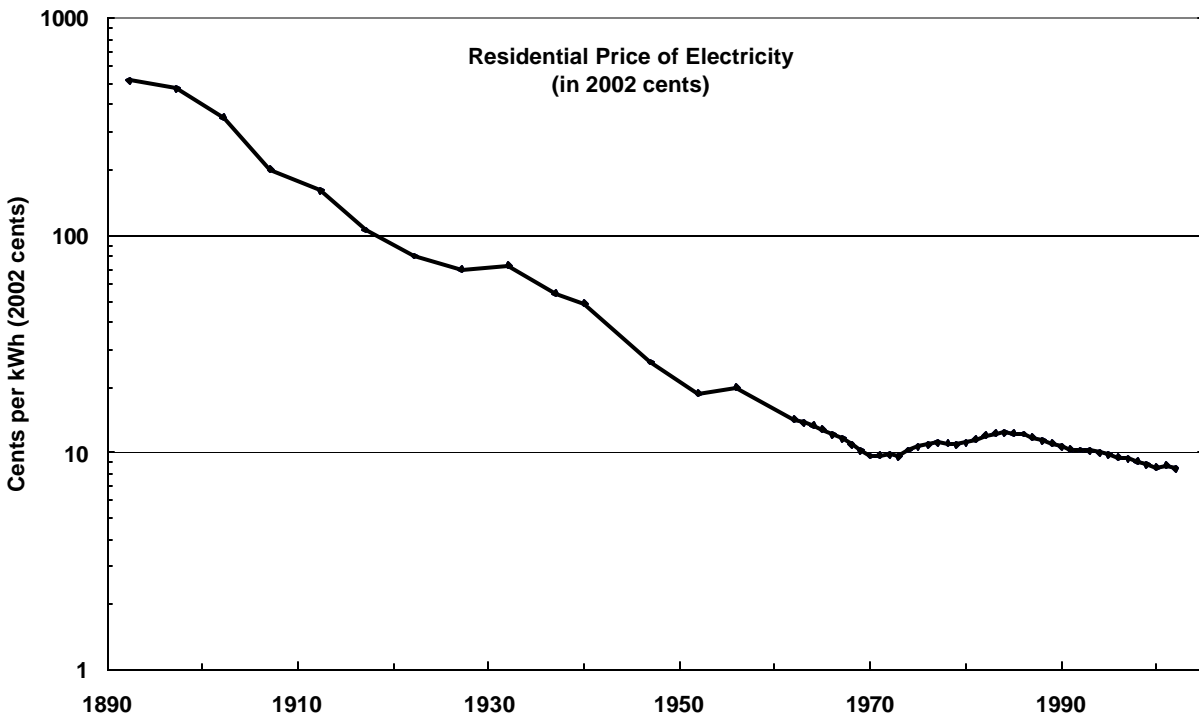**Figure 2:** Average price of residential electricity, current year cents.[5]

Figure 3: Average price of residential electricity adjusted for inflation to 2002 cents (semi-log scale).

III. Regulation

Rationale for Regulation

Economists regard electricity supply as a natural monopoly.[6] The distribution system connecting customers to the transmission lines is too costly to permit multiple lines to each residential or other small customer. The transmission system has some of the same characteristics, but there is some possibility for competition. Generation, the part of the supply chain most amenable to competition, has limited economies of scale, depending on the fuel.[7] Site expenses, environmental control costs, and connections to fuel and transmission give important scale economies.

The economies of scale mean that giving a single company the franchise to serve an area would result in lower costs for transmission and distribution and, up to a certain size, for generation. Left to its own devices, a monopoly might take advantage of its market power to raise price. One solution is to create a regulatory agency that controls price.[8] Efficient regulation is difficult, since regulators must set price to give a fair return on the company's investment, must ensure that the company operates efficiently without excess costs, and must determine when and what investments are needed. Furthermore, the regulators are appointed or elected to serve the people, not just regulate the electricity company. This means that service decisions are often made by regulators on the basis of public desire (such as continuing to serve customers who are too poor to pay their bills) rather than by utilities on the basis of dollars and cents.

Problems with Regulation

By the 1990s, a host of problems had become evident in regulation. Regulators were political appointees who (with notable exceptions) generally knew little about the business. Utilities found that they could manipulate regulators who had neither business nor technical expertise. In particular, utilities had an incentive to invest more in plant and equipment than was required (economists call this "gold-plating" the Averch-Johnson effect).[9] Utilities could borrow money at a lower rate than their allowed rate of return. This meant that each additional dollar of investment increased the return to their stockholders. For example, if 300 MW of new generation were needed, the utility could build a 1,000 MW unit and make their stockholders better off. If the cost of capacity was $1 million per MW, and the utility could borrow money for 8% and was allowed to earn a return of 10%, the additional investment of $700 million enriched their stockholders by $31 million each year. If the regulators questioned the need for so large a capacity enhancement, the utility could argue that it might be needed to ensure reliability, thereby placing responsibility squarely on the shoulders of the regulators in the case of power outages.

The regulatory era was desirable for companies (who earned reasonable profits with little risk), regulators (who faced few difficult decisions), and for customers (who saw prices fall). Everyone avoided taking risks, since there was no premium if you succeeded and you were likely to lose your job if you failed.

Better Regulation or Deregulation?

After 1973, prices rose swiftly (see Figure 2) and many customers thought that the owners, rather than the customers, should pay for bad decisions. Since regulators had to give utilities a fair return on investment, customer ire began to include regulators as well as the utilities. The most obvious answer to these problems with regulation is not deregulation, but reforming regulation. Even the most zealous deregulation proponents recognize the need for regulation of the distribution system, as well as the need to set rules for restructured markets. Making deregulation work requires better regulation.

George Stigler developed a theory of regulatory capture to describe the frequently cozy relationship between regulators and regulated companies.[10] The people who could regulate most knowledgeably were executives in the industry. Could former industry executives be trusted to serve the public interest, rather than the interests of their company or industry? Even a retired executive is more likely to be sympathetic to the problems of the company than the desires of the public. This conflict of interest has manifested itself through generous rates of return. Regulators have also been slow in pushing electric utilities to increase operating efficiency.[11]

Unfortunately, with few exceptions, federal and state regulators have not been chosen for their knowledge and experience in determining which investments were needed, whether the company was operating efficiently, and how to ensure that the company would provide reliable, high-quality service. As shown in Figure 4, most state commissioners have been lawyers or consumer advocates, presumably chosen to protect the public interest. However, a regulator with good intentions but without deep knowledge of the technology or company economics cannot make informed judgments about which investments to approve or when company operation is inefficient. Regulators can say no to an individual request for a price increase, but they are bound by law to allow companies to earn a return on their investment.

Even if an individual with the appropriate expertise were selected, that person would not have the staff or the direct knowledge that company executives have. Creating a large, knowledgeable staff at any public utility commission would be expensive and difficult. Getting the desired information and analysis would be still more difficult. Someone outside an organization finds it is all but impossible to judge whether that organization is promoting the right people and is operating efficiently. We conclude that even at its best, state regulators are unlikely to be as efficient as a competitive market in forcing a company to supply electricity at low cost with high reliability and good service.

A regulator's job is not confined to forcing the companies to provide good, reliable service efficiently. Public utility commissions must determine whether proposed investments are needed, which gives them a central role in determining the competitive strategy of the utility and the growth plan for the region. They must make myriad decisions about who benefits and who bears the costs for electricity investment. Technical competence is necessary, but far from sufficient.
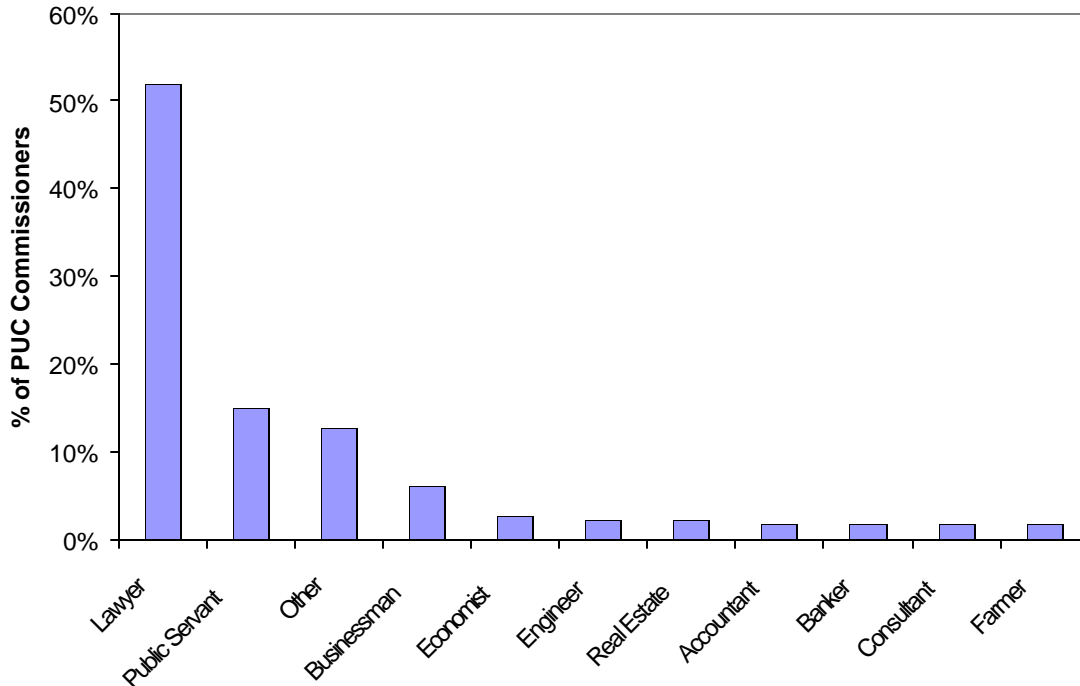
Figure 4: Professional Backgrounds of Current U.S. Public Utility Commissioners
Source: State PUC web sites. 179 commissioners were included; Idaho, South Carolina, Wyoming, and Massachusetts are missing from the sample. "Public Servant" includes all non-elected government positions. "Other" includes all employment categories with two or fewer commissioners.

Finally, the obligation of a state regulator is to the state, while many issues are regional. It is possible that regional partnerships (such as the Council of Great Lakes Governors or the Northwest Planning Council) may provide regional solutions, but the political system is set up for each state to focus on serving its residents, not those of other states in the region.

Thus, the realistic choice is how much authority to retain in an imperfect regulatory system and how much to transfer to an imperfect free market for generation. We have explored the regulatory system. We now turn to the free market for generation.

III. Factors Increasing Deregulation Cost

Economists stress that if deregulation is to bring benefits to consumers, the markets it creates must be competitive. Thus far, the bulk power markets created by the 1990s restructuring have not been competitive; it has proven difficult to design a market where no generator, or group of generators acting in concert, has market power.[12] Where competitive markets can be designed, getting to a competitive market structure often incurs large costs which can erase efficiency gains from deregulation.[13] If a competitive market cannot be achieved, prices are likely to be high and creating a free market is likely to result in higher prices than imperfect regulation. Even if markets can be made competitive at little cost, the SMD and other deregulation rules bring some inherent costs when they are implemented. Some of these costs are substantial.

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Increasing Generation and Transmission Capacity: FERC has characterized a pivotal supplier as one that could cause electricity supply to be less than demand by withholding one or more of its generation plants. FERC requires that such pivotal suppliers make their capacity available at cost in order to prevent the exercise of market power. To allow the electricity market to operate as a competitive market rather than a regulated entity, there must be sufficient generation capacity so that no supplier is pivotal. Given peak demand, it is straightforward to estimate the amount of capacity needed, assuming that all the other generators are operating. However, if one or more generators are not available, a great deal of additional capacity might be needed. Blumsack et al. generalized the notion of a pivotal supplier to include a group of suppliers acting together[12]. They estimated that the amount of additional generation capacity needed would be large and expensive.

The current transmission system was designed to get power from a particular utility's generators to its customers. A competitive market gives each customer a choice among suppliers and so the transmission system might be asked to carry electricity over much greater distances and from different generators to customers. Thus, to support a competitive market, a good deal more transmission capacity is required. Blumsack et al. calculated that the additional cost of the new transmission could be large.

The cost of the additional generation and transmission needed to support a competitive market is so great that we doubt that the savings from a competitive market would be able to offset this amount

Paying Market Clearing Price for All Generation: Another cost is incurred by the structure of the spot auction markets envisioned by SMD. These markets (independent of contract markets, and illustrated in Figure 5) pay the market-clearing price, not average total unit cost, for all MWh generated.
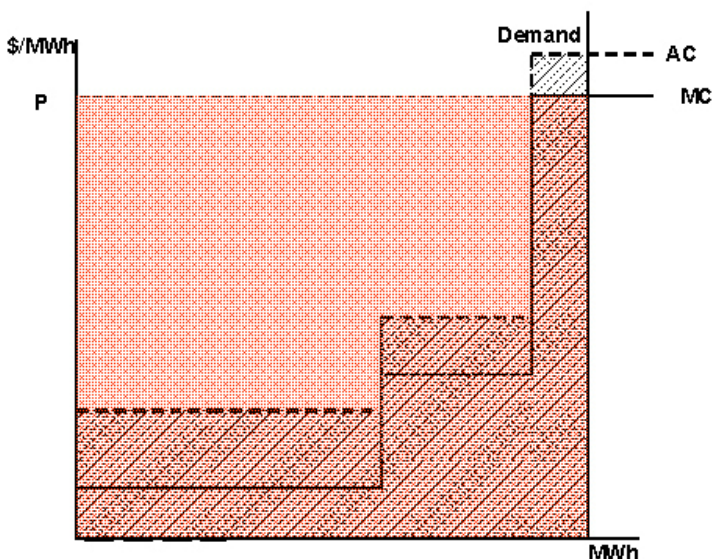

Figure 5: Average Cost (AC) and Marginal Cost (MC) Curves Under Deregulation.

The solid line in the figure is the additional (marginal) cost of generation per MWh (MC), while the dashed line in the average total cost, including fixed costs, of generating each MWh. The three cost levels represent baseload, shoulder, and peaker units. The vertical line is the number of MWh demand during a particular period, as estimated by the ISO. In a competitive market, all generators would bid their marginal cost for each unit and the market clearing price would be P. Since the market-clearing price is paid to all generators in a uniform price auction, the total amount paid to generators would be P times the number of MWh, a rectangle that is the shaded area. Under regulation, generators are paid their average (unit) costs and so the total amount paid is the cross-hatched area. At times of high demand, such as shown in the figure, the amount paid under a uniform price auction is much greater than under an average cost system.

This auction has the double faults of overpaying baseload generation during peak periods while simultaneously discouraging new investment. At times of high demand, baseload power that costs perhaps $30 per MWh would be paid $500 per MWh. However, in a competitive market, the highest cost peaking units would never be paid more than their MC and so they would not recover their fixed costs. Even new baseload plants would have trouble earning back their capital costs.[14] As a result, investors would be unwilling to build new units in competitive markets, particularly peakers. To solve this problem, investors would have to be offered an incentive equal to the fixed costs in order to get them to build the plant.

A revision of the auction rules to pay-as-bid pricing rather than uniform pricing has been adopted in the United Kingdom; such a system has been proposed for the U.S.[15] Theory and practice have shown that such a move would ultimately accomplish nothing.[16] In practice, everyone knows the capacity of each plant, its heat rate, and the approximate price of fuel. Thus, all generators can estimate the MC of every available generation plant. If they assume that everyone will bid their plants at MC, it is straightforward to estimate the market clearing price for any level of demand. In a pay-as-bid auction, a generator would estimate that the MC of the plant required to produce the required level of electricity and bid their low priced generators just under this price. For example, if generator X has a baseload unit whose MC = $15 and a shoulder unit whose MC = $35 and the generator estimated that the market clearing price would be $55, she would bid her two units at $54.99. Thus, there is little difference between setting up the market as paying the market clearing price to everyone versus paying each generator what they bid.

If the wholesale market for electricity cannot be made competitive, one solution would be to have, at most, a tiny proportion of the electricity sold in the auction market. The more generation that is under contract at average cost, the less electricity would have to be purchased in the auction and so the smaller would be the "excess" amount paid. The situation in California was particularly acute since there was almost no generation under contract. However, when California set out to negotiate long-term contracts, they were unable to secure supply at anything close to AC. While the California situation was somewhat atypical, there is no assurance that any company would be able to negotiate contracts at rates close to AC.

Assuming that companies could find suitable sites for new generators, one way to negotiate long-term contracts at AC would be to allow the length of the contract to encompass the life of the plant. For this type of contract, a competitive market would force the winning bids down to expected AC.

Such contracts would go a long way towards minimizing the costs associated with restructuring, but only if risks are properly assigned.

Creating new institutions: Deregulation requires new institutions, primarily to perform functions formerly carried out by vertically integrated utilities. An independent systems operator is needed to coordinate supply and demand. A regional transmission operator is needed to manage transmission. Creating an effective new institution is expensive and time consuming. The start-up cost for the California ISO has been quoted at between $300 million and $1 billion, while its operating budget is nearly $200 million per year. The start-up cost for PJM has been quoted at nearly $150 million, with an annual operating budget of $250 million per year.[17] The ISOs cover their operating costs through fees imposed on system participants and congestion payments. Insofar as the ISO/RTO lowers company expenses by rewarding efficient production and reducing transactions costs, these benefits should be deducted from the cost of the new institutions. An important component is trading that requires training individuals and acquiring hardware and software. Enron's operating expenditures in 2000 to take part in the various energy markets (gas, oil, and electricity) were quoted at $449 million.[18] In a restructured market, the ISO/RTO and some other costs are the equivalent of an unfunded mandate. Firms must either assume the costs or exit the market. Therefore, the social and private costs of setting up new market institutions must be accounted for in determining whether restructuring yields a net social benefit.

The point is that deregulation brings additional costs, some of which are substantial. Over the first few years, these costs are likely to be greater than any short-term savings,[19] meaning that costs will rise. Regulators can require that retail prices fall, but these prices will not compensate for the additional costs and so, eventually, prices will have to reflect the higher costs.

Increased risk in a capital-intensive industry: Until recently, regulation helped to lower the risks associated with utility company stocks and bonds. Each year, regulators and utilities could count on an increase in demand, improved technology for generation and transmission, and a decline in the real price of fuels. Environmental regulations were coped with, competition was nonexistent, and the utility was essentially guaranteed a rate of return on its investments. Utility stocks were considered to be extremely low risk, meaning that investors were willing to lend utilities money at low interest rates.

After 1973, demand became less predictable, with loads actually falling in some areas. Demand, which grew exponentially from 1949 through 1973 (at 7¾ % per year) abruptly shifted to much slower linear growth (at the rate of 73 billion kWh per year). New generation units were more expensive and less reliable than expected, fuel prices fluctuated in a wide range, environmental regulations became increasingly stringent, and finally deregulation introduced competition for 40% of U.S. load. The result was sharply increased costs following almost a century of cost decreases. Consumers were unhappy and pressured regulators to deny or at least delay rate increases. As a result, utility profits fell and investors avoided these companies.

The risks associated with deregulation in particular have led investors to demand much higher rates of return, although often they are not willing to supply the investment at any reasonable rate. The result is a marked increase in the cost of new plant and equipment. For a new coal-fired generation plant, capital costs represent about 2/3 of AC; for a new transmission line, capital costs are almost

100% of AC. When a capital-intensive company faces sharply higher costs for securing new capital, total costs rise significantly. If a deregulated company had to renegotiate its loans and bonds at market rates of return, accounting for risk, and sell all its stock at market value, total costs would increase by more than 30%.

Under rate-of-return regulation, the risks are borne by ratepayers. Under deregulation with fixed retail prices, the risks are shifted to investors, although California shifted some of that risk back to ratepayers when retail rates were raised in the midst of the power crisis. The uncertainty cannot be wished away. Placing the risks on rate-payers lowers borrowing costs but will not lower retail prices if utility companies make bad investments. However, the current uncertainty about industry restructuring and how much investors will be reimbursed has needlessly forced borrowing rates sharply higher.

IV. Aligning Risk with Reward

Risk in the electric power industry can be broken down into five categories. A successful restructuring effort will place the burden of each risk with the party that is best-equipped to handle that risk; the party bearing the risk should get the rewards. Some of the institutional arrangements we suggest are already in place; some (particularly regarding transmission) are not. We make the following distinctions and discuss each in turn:

1. Uncertainty over company efficiency and management competence;
2. Demand and price uncertainty;
3. Fuel price uncertainty;
4. Uncertainty over transmission availability (congestion risk); and
5. Uncertainty regarding future environmental regulations.

1.Uncertainty about the competence of management should be handled by companies and investors. Investors are used to evaluating this risk and feel comfortable with it; customers know little or nothing about it. Energy contract terms should therefore specify a price per MWh and not take the form of loan guarantees or joint ownership. In other words, firm energy contracts should be the norm. For example, a life-of-plant contract for a baseload generator should specify a price and a number of MW each hour with outage time for maintenance and some allowance for unscheduled maintenance. The contract should include a cost (not including fuel) escalation clause and a penalty for each MWh not delivered.

2. Uncertainty about demand should be handled by the ISO. The ISO is responsible for forecasting both short- and long-term demand. They know the most about the level of future demand and should absorb this uncertainty. Thus, it is also in the ISO's interest to insist on a specified quantity for all energy contracts. Although the ISO would handle demand uncertainty, the risk would ultimately be placed on the residents of the area. Regulators would then be responsible for ensuring that the ISO's demand forecasts were adequate and accurate.

3. Uncertainty about fuel prices should be handled via futures contracts. Future natural gas prices are highly uncertain. For coal and nuclear fuel, long-term contracts can take away fuel price risks. For natural gas (and oil), current futures markets extend only six years into the future and the

volume of trades is low beyond 18 months into the future. We expect that a robust futures market would develop for longer periods if a number of NGCC plant owners wanted to shed some of risk of future fuel prices. Otherwise, uncertainty beyond the six-year horizon could push borrowing costs even higher. If the gas futures market were limited to six years, someone building a new NGCC generator would probably bid only for a six year contract, quoting a price that covered the futures contract and their expectations about gas prices after that date, with adjustment for uncertainty and risk aversion. The capital cost of the plant would be largely amortized over the six years of certain prices. If the price of gas after six years allowed the plant to compete, they would sign a new contract for up to six years or shutter the plant if the price of gas didn't allow it to compete.

4. Uncertainty about transmission availability should be handled by the RTO. They have the best information on the transmission system and future demands. If additional transmission is needed, they should be given the authority to provide financial terms that would induce investment. We have proposed a mechanism for paying for this transmission elsewhere.[20] This means that the long-term contract should specify electricity at the generator bus-bar, rather than delivered electricity. Insofar as there is uncertainty about future congestion, specifying the contract at the plant gate would impose the costs of this uncertainty on the RTO. As with the discussion of shifting the demand uncertainty, shifting the risk-management responsibility to the RTO means that, ultimately, electricity consumers would bear the risk. Customers and regulators should thus be strongly motivated to make sure that the ISO and RTO are acting prudently.

5. Uncertainty about future environmental regulations is high and no single party has expert knowledge of future regulations. However, the generation company can choose a fuel, technology, and plant design to lower the risk. For example, the mining, transport, and burning of coal has much higher environmental loadings than does the extraction, transport, and combustion of natural gas. Thus, a coal plant should have an environmental risk premium compared to an NGCC. Even within coal technology, there should be a risk premium for a 30-year contract with a mine that pushes a mountain top into the adjoining valley in order to strip mine the coal. Similarly, a pulverized coal plant should have an environmental risk premium compared to a coal gasification plant, since the latter would have much lower pollution emissions. Even the risk of future greenhouse gas regulation could be hedged by building a coal gasification plant with provision for later installation of equipment to separate the carbon dioxide for storage. Thus, the risks concerning environmental regulations should be placed on the plant owner, since that party has the greatest control over the costs of future regulations.

V. Structuring a Competitive Market

Eliminating regulation creates a free market. Creating a competitive market is more difficult; it requires that no seller have the power to increase profit by raising price. In other words, market participants must see themselves as price takers, not price setters. Designing a market that prevents a company from having market power is much more difficult for electricity than for other goods and services. In other work, we have generalized the notion of a pivotal supplier to multiple suppliers acting in concert to withhold supply and raise price. We show that for many hours, 2 to 6 firms acting in concert could cause a blackout in California, PJM, or New York unless the ISO were willing to pay their price.[21]

The Sherman Antitrust Act makes it a crime for companies to make an agreement to raise prices. If there is no agreement or communication among the parties, acting in concert is not a crime. The potential for implicit collusion through repeated interaction in hourly electricity auctions is widely recognized. With inelastic demand, it is in each firm's interest often to bid their capacity at a high price. Sarosh Talukdar has created a simulation with 10 firms, each having 10% of total system capacity. These firms are not as smart as human traders and learn slowly. Yet, even when capacity is twice the amount of electricity needed, the suppliers manage to raise the price to monopoly levels.[22] Stephen Rassenti, Vernon Smith, and Bart Wilson reach almost identical conclusions in an experimental setting.[23]

Since electricity cannot be stored, designing a market that prevents a company from having market power is much more difficult for electricity than for other goods and services. Below we describe five necessary features for a competitive bulk power market.

Retail Prices Must Reflect Costs: Both the simulations by Talukdar and the experimental evidence in Rassenti, Smith, and Wilson indicate that allowing consumers to submit demand bids into the auction can reduce monopoly power dramatically. Calculations by Severin Borenstein indicate that gains to consumers under real-time pricing would be substantial.[24] Under regulation, consumers pay a fixed price for electricity, ignoring the low generation and transmission costs when demand is low as well as the high costs when demand is high. As a result, consumers see no reason not to run their electric appliances during hours of peak demand, resulting in a load-duration curve with many high-cost hours. The resulting cost of generating the last kilowatt-hour during a summer peak might be 10 or even 100 times greater than the price the consumer pays.

Under rate of return regulation, the cost of the peak kWh mattered little, since the costs were averaged over all kWh. The utilities profited from the high demand peaks because they had to build more generation capacity (the Averch-Johnson effect); the regulators liked the situation since people got to do what they wanted with little penalty, and consumers liked the situation because they could do what they wanted and have the high costs hidden. However, in a competitive market, this increase in cost means that price will be much higher because of the uniform-price auction, as shown in Figure 5. Supplying electricity would be more efficient if the load-duration curve could be flattened; the implications for consumers in a uniform-price auction are even more important.[25]

Assume that a typical load-serving entity charges 9 cents per kWh, of which 3 cents represents the cost of generation. Further assume that the cost of the last MWh of generation rises from $30/MWh to $120/MWh. If retail price reflected cost, the retail price would rise from 9 cents to 18 cents. Econometric studies suggest that a doubling of electricity prices would lead consumers to purchase about 7-20% less electricity.[26] If the load-duration curve were flattened by this amount, the cost of generating the marginal MWh would fall substantially. Even more dramatic would be the peak times when wholesale generation prices per MW rise to $500 or even $10,000. If consumer prices reflected these generation prices, they would rise to $0.56 or even $10.06 per kWh. Consumer demand for electricity would fall substantially at 56 cents per kWh; it would all but disappear at $10.06 per kWh. The point is that reflecting wholesale generation in retail prices would flatten the load-duration curve to the point where there would be substantially less demand for peak generating

units and the wholesale price of power would be constrained to much lower levels than we have seen in the past.

Figure 6 shows the load-duration curves for PJM, with and without consumers facing the real price of energy. The solid curve represents the current load-duration curve where consumers pay a fixed price, regardless of the wholesale price. The dotted curve[27] reflects the changes that would occur if the price elasticity were -0.2. This adjusted curve would require much less peaking capacity and would make greater use of capacity during low demand periods.

Some consumer groups are opposed to having consumers face real prices, arguing that they are not able, or at least are unwilling, to deal with rapidly changing prices. We disagree. Drivers see the price of gasoline and can make informed decisions. Many airline fares vary by time of day and day of week. Consumers are able to process this information and make informed decisions. It is more difficult for consumers to react to electricity prices, since they use electricity 24 hours a day, even when they are not at home. In the short term, time of day pricing with a seasonal component could move closer to the goal and allow consumers to react by, for example, set-back thermostats.[28]
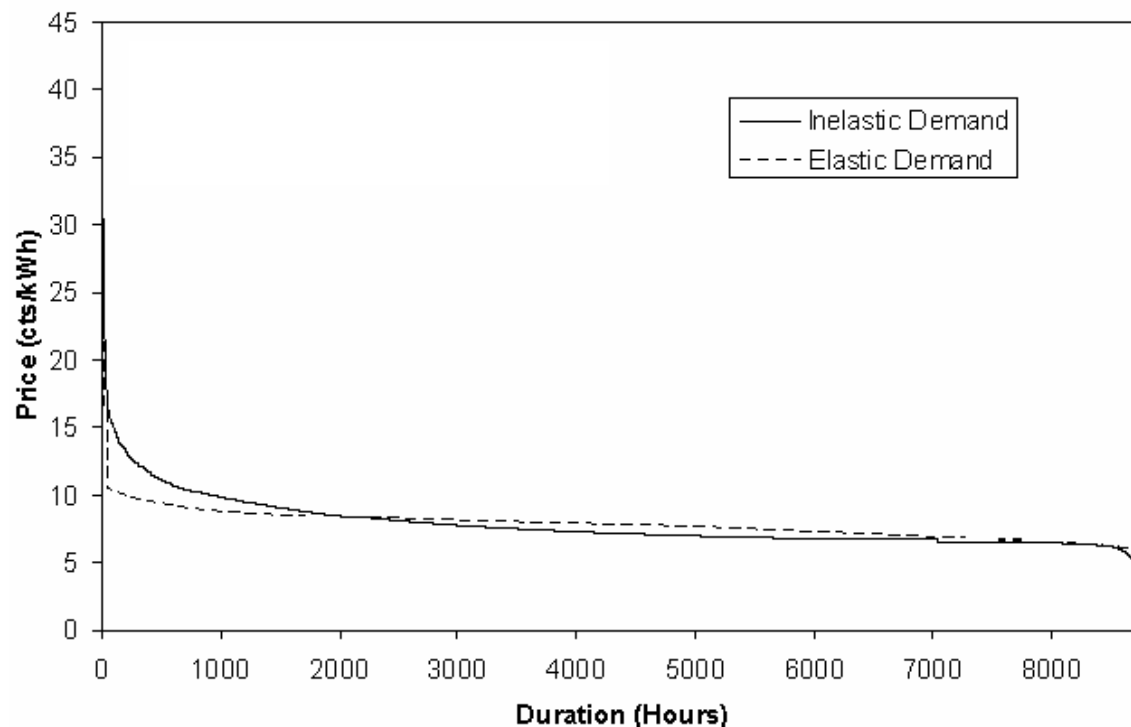

Figure 6: PJM load duration curves for inelastic and elastic (e = -0.2) demand. Data source: PJM. Maximum price with inelastic demand is 88 cents / kWh; the 40 highest priced hours are not shown, to clearly represent the comparison.

Establishing Complete Markets: In addition to a competitive market for real power, a competitive electricity market requires that all parts of that market be competitive. That means that there must be competitive markets for regulation, spinning and non-spinning reserves, and reactive power. Establishing and operating each of these markets is costly. Every time a new market is created, new

opportunities are created to exercise market power. Each of these new markets must be structured to facilitate competition. Each must be monitored to detect and punish fraud and collusion.

Creating markets for these ancillary services is not straight-forward. For example, reactive power is location specific, since it attenuates with distance. Location is important in all these markets. For example, the market for real power depends on the capacity and location of the transmission links. The value of reserves depends on the location of the generating plant providing the reserves.

Timing of Auction Markets: The SMD has a day-ahead and a real time market. This timing does not correspond to the physical realities of electric generating stations and therefore makes little sense. Baseload plants should be operated continuously at full power except for yearly maintenance once they are turned on. Bidding these plants into the day-ahead or real-time markets leads to gaming or inefficiency. If they are bid at a zero price, they would always be chosen and so operation would be efficient. In a uniform price auction, they would be paid a high price at times of high demand and almost nothing at times of low demand. Whether they were paid a high or low price depends on the amount of capacity available and the shape of the load-duration curve. If the auction is pay-as-bid, the owner faces formidable difficulties. If she bids a zero price, she is paid zero. If she bids a higher price, she would have to shut down the unit during some hours, which is extremely costly. She would have to estimate the market clearing price for each hour and bid just below that.

The same difficulties arise, but to a lesser extent, for shoulder and peaking plants. Shoulder plants are operated for 8 to 24 hours per day. Once they are turned on, they should be operated at full power for that interval. The day-ahead market is hour by hour and does not reflect the reality of operating these plants. Efficient operation requires an auction a day ahead that asks for bids for generation that will run 3 to 24 hours. Even peaking plants cannot react quickly, unless they are on spinning reserve. They need more warning than is contained in the real time market. In general, efficiency is achieved by matching unit ramp rates to auction market periods in a better way than is being done at present. We conclude that the timing of these markets needs to be thought through again. However, balkanizing the markets in this way could increase opportunities for exercising market power in one or more of the divided markets since the number of competitors is restricted. Balkanized markets may not have enough sellers or buyers to clear.

Transmission Must Facilitate Competition: Transmission links generators to distribution lines and then to customers. The transmission manager could act to favor some generators, disadvantage some consumers, and generally make the market less efficient. Even if transmission is controlled by an RTO, there must be adequate capacity in the right places to link generators to consumers. Almost all transmission capacity was put into place during the regulated era, when a vertically integrated utility wanted to connect its generation to its load. In the deregulated era, many other generators could serve the load and some are likely to have low costs that lead customers to want to buy from them. Thus, deregulation requires a much more extensive transmission network. The FERC's SMD provides a mechanism to manage congestion in the transmission network (nodal pricing). However, if this is the only mechanism used to compensate transmission owners, there are no incentives to build new lines since nodal prices will equalize once the congestion has been relieved. We have argued that a two-part tariff composed of both nodal prices and a charge for the MW-miles of electricity shipped is the proper compensation structure.[29]

Transparency: A competitive market requires informed buyers. For example, if a customer values reliability, they must be able to choose a supplier on the basis of reliability data. In the USA, those data are exceedingly hard to acquire, whereas in New Zealand and Australia historical and current reliability data are available on the Internet.

VI. Conclusions

Government must be an active participant. States that want lower prices but refuse to give up the traditional regulatory structure should: 1) Reform to allow more cost-effective regulation, emphasizing efficiency and low cost operation more than programs that raise costs or help special consumers. 2) Increase the flexibility of regulation to allow innovation such as microgrids and real-time pricing, while encouraging competitive efficiency in labor and equipment. 3) Establish innovative programs that provide market incentives to control environmental discharges as well as to fulfill critical missions provided by electricity when the power does fail.

States that have restructured their electricity markets need to accomplish tasks 2) and 3) above. These deregulated states continue to impede innovations such as microgrids and need to do more to establish market incentives for controlling environmental discharges and fulfilling critical missions when blackouts occur. In addition, these deregulated states should not be naïve in thinking that they can devise a structure that will allow them to neglect the electricity markets. They must: 1) put more resources into monitoring to detect and punish the types of problems that arose in California. 2) Devise a mechanism that reduces the variability in return to investors, thereby reducing the cost to the consumer (this can take the form of a regulated monopoly as in 2/3 of the states, or the form of the mix of private risk and government loan guarantees proposed by William Rosenberg[30] for both regulated and deregulated states).

Substituting markets for traditional regulation is a choice among policy instruments to achieve a goal of lower prices rather than a statement about goals. Thus, clear goals must be articulated, and periodic reviews are needed to assess which instrument is achieving the goals better.

In summary, the US electricity sector is in an uncomfortable situation. Reregulation is unattractive, but less so than proceeding to implement SMD. Major improvements in regulation are unlikely, given the nearly 100 years of experience. Designing better market structures seems more promising. However, we have enumerated a formidable array of difficulties to be overcome before a deregulated market can be efficient and serve the needs of consumers.

Deregulation is not all-or-nothing. A vast array of market designs have different degrees of regulatory control. For example, the California ISO in 2000 had little control over a free market while PJM has a great deal of control. The question for market designers and policy makers is how to design a structure that will eliminate the worst problems of regulation and give the benefits of competitive markets. Blind faith is unlikely to produce a free market that is competitive.

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Endnotes:

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[1] Center for the Advancement of Energy Markets, 2003. *Estimating the Benefits of Restructuring Electricity Markets*, available at www.caem.org.

[2] c.f. Rebecca Smith, **"**States Face Fights As Caps Expire On Electric Rates; Deregulation Deadlines Highlight Disparities Between Customers, Utilities." *Wall Street Journal* (Eastern edition), New York, N.Y., Aug 17, 2004, at A.1.

[3] Jay Apt, "Retail Electricity Prices in The United States, 1990-2003", in preparation, discusses the techniques used in removing seasonal periodicities from state-by-state sales and revenue data compiled by the U.S. Energy Information Administration, *Historical 1990 through Current Month Retail Sales, Revenues, and Average Retail Price of Electricity by State and by Sector,* available at http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls and *Form EIA-826 Database Monthly Electric Utility Sales and Revenue Data*, available at http://www.eia.doe.gov/cneaf/electricity/page/eia826.html.

[4] "Application of Long Acre Company," *Electrical World* 52:1, at 8-9 (July 4, 1908).

[5] Richard F. Hirsh, *Power Loss* (2001), 406 pp., MIT Press, Cambridge, Figures 2.1 and 3.3 inspired these figures, which have been compiled from the data sources he cites and updated with data from U.S. Department of Energy, Energy Information Administration, Electric Power Annual Table ES, available at http://www.eia.doe.gov/cneaf/electricity/epa/epates.html and the U.S. Bureau of Labor Statistics Consumer Price Index Research Series Using Current Methods (CPI-U-RS), available at http://www.bls.gov/cpi/cpiurstx.htm.

[6] Distributed generation can eliminate most of these scale economies: A small generator can compensate for the lower efficiency in generating electricity by using the "waste heat." The facility would use much less transmission. However, unless, it is completely independent of the grid, it would require some of these services and thus reflect some of the scale economies.

[7] Laurits Christensen and William Greene, 1976. "Economies of Scale in U.S. Electric Power Generation," *Journal of Political Economy* 84:4, at 655-676.

[8] Other responses have been public power systems and rural electric cooperatives. These have not played a dominant role in the United States. Net generation in 2002 by publicly-owned utilities was 9.7% of total U.S. net generation, by cooperatives 4.5%, and by federal power agencies 7.1%, totaling 21.4%. Source: *2004-05 Annual Directory & Statistical Report*, American Public Power Association, available at http://www.appanet.org/aboutpublic/index.cfm?ItemNumber=2691&sn.ItemNumber=2039.

[9] Evidence of overinvestment by regulated utilities can be found in Michael Spann, "Rate of Return Regulation and Efficiency in Production: An Empirical Test of the Averch-Johnson Thesis," *Bell Journal of Economics* 5:1 (1974), at 38-52. A working paper by Catherine Wolfram ("The Efficiency of U.S. Electricity Generation After Restructuring," available at http://www.ucei.org) suggests that operating efficiency has not improved with restructuring.

[10] George Stigler, "The Theory of Economic Regulation," *Bell Journal of Economics and Management Science,* 2:1 (1971), at 3 – 21.

[11] Energy Information Administration, 1997. "Electricity Reform Abroad and U.S. Investment," available at http://www.eia.doe.gov/emeu/pgem/electric/

[12] The evidence that generators exercised oligopoly power in California is voluminous; see Severin Borenstein, James Bushnell, and Frank Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market, *American Economic Review* 92:5 (2002), at 1376 – 1405, and Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," *Energy Journal* 23:4 (2002), at 1 – 35. Seth Blumsack, Dmitri Perekhodtsev, and Lester B. Lave ("Market Power in Deregulated Wholesale Electricity Markets: Issues in Measurement and the Cost of Mitigation," *The Electricity Journal*, November 2002, at 11-24) show that restructured markets in California, New York, and PJM have highly oligopolistic market structures. The problems with recently-restructured electricity markets must be contrasted with the early power pools in the Western U.S., which were fairly competitive. See Sam van Vactor and Dona Lehr, "Evolution of Power Price Structures in the Western Power Market," in *The Evolving U.S. Power Market*, Risk Publications, June 1997.

[13] Seth Blumsack and Lester B. Lave, "Mitigating Market Power in Restructured U.S. Electricity Markets," *Papers and Proceedings of the 24th North American Conference*, U.S. Association for Energy Economics, July 2004.

[14] A gas-fired generator with capital costs of $600/kW and a heat rate of 7,100, buying fuel at $5/mmBTU would need to operate for around 8,000 hours per year and receive a market price of at least $80/MWh to recover its fixed and variable costs. In recent years, prices in PJM have reached these levels in only a small number of hours.

[15] Natalia Fabria, Nils-Hendrik von der Fehr, and David Harbord, "Modeling Electricity Auctions," *The Electricity Journal*, August/September 2002, at 72 – 81.

[16] Economic theory predicts that bidders will adjust their strategies in a pay-as-bid auction to mimic the outcome of the uniform-price auction (Peter Crampton, Alfred E. Kahn, Robert H. Porter, and Richard D. Tabors, "Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond," *The Electricity Journal*, July 2001, at 70 – 79, and Giulio Federico and David Rahman, "Bidding in an Electricity Pay-as-Bid Auction," *Journal of Regulatory Economics* 24:2 (2003), at 175 – 211). The theory is backed up by experimental evidence (Stephen Rassenti, Vernon Smith, and Bart Wilson, "Discriminatory Price Auctions in Electricity Markets: Low Volatility at the Expense of High Price Levels," *Journal of Regulatory Economics* 23:2 (2003), at 109 – 123).

[17] Operating costs for the CAISO and PJM can be found at http://www.caiso.com and http://www.pjm.com. Start-up cost estimates for the CAISO and PJM are from Sam van Vactor, *Flipping the Switch: The Transformation of Energy Markets*, Ph.D. Dissertation, University of Cambridge, Cambridge U.K., February 2004, and Margo Lutzenheiser, *Comparative Analysis of*

RTO/ISO Operating Costs, Public Power Council, August 2004, available at
http://www.ppcpdx.org/Tx/ComparativeAnalysisAug1720042.pdf.

[18] Enron's financial reports are still available at http://www.enron.com. Although the cooking of Enron's books is now widely acknowledged (and the exact figures therefore suspect), the point is still that the cost to participate competitively in restructured electricity markets is too high for many small players.

[19] One estimate, by M. Scott Niederjohn ("Regulatory reform and labor outcomes in the U.S. electricity sector", *Monthly Labor Review,* 26:5 (May, 2003) at 10-19) indicates that employment dropped 29% in restructured states and 19% in other states since the peak in 1991. That 10% difference would have lowered cost by 0.7%, since labor costs represent only 7% of electricity cost.

[20] Jay Apt and Lester B. Lave, "Electric Gridlock: A National Solution," *Public Utilities Fortnightly*, (2003) 141(18) at 14-16.

[21] Blumsack, Perekhodtsev, and Lave, *supra* note 7.

[22] "The Power Systems Engineering Research Center and Some Grand Challenges," Seminar presented to the Carnegie Mellon Electricity Industry Center on March 28, 2002. Available at http://www.cmu.edu/electricity.

[23] "Controlling Market Power an Price Spikes in Electricity Networks: Demand-Side Bidding," *Proceedings of the National Academy of Sciences,* 100:5 (2003), at 2998 – 3003.

[24] "The Long-Run Effects of Real-Time Electricity Pricing," UCEI Working Paper WP-133, July 2004, available at http://www.ucei.org.

[25] Rassenti, Smith, Wilson (*supra*, note 10) find in their experiments that undergraduates are able to figure out how to handle pay-as-bid auctions and so that is little or no price difference between a uniform-price and pay-as-bid auction.

[26] This equates to a price elasticity of between -0.1 and -0.3. See, for example, Douglas Caves and Laurits Christensen, "Econometric Analysis of Residential Time-of-Use Electricity Pricing Experiments," *Journal of Econometrics* 14 (1980), at 287-306 and H.S. Houthakker, "Some Calculations of Electricity Consumption in Great Britain," *Journal of the Royal Statistical Society (A)*, 114:3 (1951), at 351-371.

[27] Using data from PJM for the year 2001, we make a rough estimate of the impacts of price-responsive load, assuming a price elasticity of -0.2. First, we use the assumed elasticity to calculate how load would change as a function of hour-to-hour changes in price. Next, we estimate what the price would be with the new level of demand using the regression:

$$\log(\text{Price}) = a + \text{ß} \times \log(\text{demand}) + d_1 \times D_{5000} \times \log(\text{demand}) + d_2 \times D_{5100} \times \log(\text{demand})$$
$$+ d_3 \times D_{5200} \times \log(\text{demand}) + e$$

where D_{5000}, D_{5100}, and D_{5200} are dummy variables indicating demand levels above 5,000 MW, 5,100 MW, and 5,200 MW. The error term contains a first-order autocorrelation correction. The coefficients and standard errors of the regression are shown below.

Coefficient	Estimate	Standard Error
a	-4.49	0.092
ß	0.63	0.009
d_1	0.04	0.004
d_2	0.04	0.005
d_3	0.03	0.005

Estimated parameters from regression equation. $R^2 = 0.63$.

[28] Borenstein (*supra*, note 16) asserts that time of day pricing gives only a small proportion of the gains that would come from real time pricing.

[29] Apt and Lave, *supra*.

[30] William G. Rosenberg, Dwight C. Alpern, and Michael R. Walker. "Deploying IGCC in This Decade with 3Party Covenant Financing" Summary, Cambridge, Massachusetts: Belfer Center for Science and International Affairs, Kennedy School of Government, Harvard University, 2004, available at
http://bcsia.ksg.harvard.edu/research.cfm?program=ENRP&pb_id=413&gma=11&gmi=110.