Lessons from the Failure of U.S. Electricity Restructuring

Seth A. Blumsack, Jay Apt, and Lester B. Lave

Blind faith is unlikely to produce a free market that is competitive. Substituting markets for traditional regulation is only one choice among many policy instruments to achieve a goal of lower prices; such substitution should not be in itself a goal.

1. Introduction

Several authors have presented arguments and evidence that deregulation at the state and federal level has delivered its promised benefits of lower prices and more competitive markets. The Center for the Advancement of Energy Markets has estimated that consumers in the Pennsylvania – Maryland - New Jersey RTO (PJM, which now covers much of the mid-Atlantic and parts of the Midwest) will benefit by over $30 billion due to restructuring.[1] The ISO/RTO council argues that investment in the aging U.S. transmission system has proceeded at a faster pace in restructured RTO areas than in traditional utility areas.[2] Paul Joskow has made many of the same arguments, but claims that the benefits have been more modest (although still positive).[3] Cambridge Energy Research Associates (CERA) estimated that "US residential electric consumers paid about $34 billion less for the electricity they consumed over the past seven years than they would have paid if traditional regulation had continued."[4] However, the CERA report does not mention that much of this computed savings was due to mandated residential rate reductions of up to 15%, which expire soon. Nor does the CERA report include the $25 - $40 billion losses in California's debacle, nor the losses in nearby regulated states such as Nevada whose prices rose 60%.

Our research shows that there is no evidence that restructuring has produced any measurable benefit to consumers or to the systems that have restructured. In particular:

- Comparison of industrial electricity price data between restructured and non restructured states shows that there no evidence of a substantial reduction in price, or even in the rate of price change, in restructured states,[5] and the record on overall operations costs and thermal efficiencies is mixed.[6]
- Restructuring has introduced several elements into the industry that act to raise costs, not lower them.[7] These include uncompetitive and incomplete markets for essential services, paying market clearing prices for all generation, expensive new institutions, and a large increase in the cost of capital due to increased uncertainty. The first of these applies to some industries with successful restructuring records. It may be that appropriate regulatory involvement can lead to conditions that foster lower prices in the electricity industry as well, but issues such as shared transmission infrastructure must be resolved.
- Retail competition in the U.S. has faltered. Even in states that initially saw high levels of interest on the part of consumers and third-party electric service providers (ESPs), the markets for alternatives to the incumbent utility have all but dried up.
- The U.S. transmission system was not designed to handle the volume of long-distance

> transactions generated by multi-regional electricity markets. Nodal pricing has failed to produce the appropriate incentives for beneficial grid expansion. Even if a market-based pricing scheme could be devised to promote investment, siting difficulty may prove to be an even more significant impediment to creating a transmission system that facilitates wholesale competition.

No one seriously proposed that restructuring take the form of suddenly eliminating state and federal regulation. Each utility owned the transmission and distribution lines in its area as well as essentially all of the generation. Thus, each utility had a monopoly and (in the absence of open-access regulations or power pool agreements) could have extracted massive profit by raising prices. There was no uniform model for transforming a regulated market into a competitive one. First California and Pennsylvania, and then other states, committed themselves to deregulation and then worked out market structures that they thought would bring the benefits of a competitive market. Deregulation was assumed to be in the public interest, whether in large urban centers or sparsely populated rural areas.

Deregulation became the end, rather than a means of benefiting society. If consumer welfare is the primary criterion for restructuring success, then restructuring should be frozen until the current, costly experiments have been evaluated to see if there is a benefit and, if so, which, if any, of the current structures is most likely to deliver social benefits.

2. Retail Prices Have Not Fallen Under Competition

Advocates of deregulation argued that competition in wholesale markets would benefit consumers. Several studies have claimed that deregulation delivered large benefits to consumers. The Center for the Advancement of Energy Markets has claimed savings in PJM for all customer classes as a result of wholesale and retail competition.[8] Others have calculated that residential and industrial prices in eight restructured states may have decreased at an average rate of one-half percent per year.[9] Based on this evidence, it is tempting to conclude that electricity sector reforms have been successful, at least in this one respect.

Full analysis of the actual prices paid by electric consumers leads to a more disappointing conclusion. Where prices have fallen they have done so in large part because regulators forced them down. Pennsylvania's residential prices were required to fall by 8%, which should have reduced all retail rates by at least 2.6%; CAEM and Paul Joskow report prices fell by roughly 1%. For much of the retail sector, regulators have maintained control of residential and many commercial prices, while freeing large industrial customers, who have the resources and best incentives to search for the lowest electric prices. If competition is to lower prices for any sector, the industrial sector would appear to be the best bet.

Jay Apt has examined actual industrial electricity price data for each state since 1990.[10] There is no evidence that prices for industrial customers have gone down since restructuring; in many cases they have actually increased more than prices in states that remained regulated. He shows that there is no correlation between restructuring and the annual rate of price change.

Using New England as an example, the average annual rate of industrial price change for Connecticut, Massachusetts, Maine, New Hampshire, New York, and Rhode Island from January

1990 to one month prior to the beginning of the phase-in period for industrial competition was 0.9% per year increase. The corresponding annual rate after phase-in of competition was -1.7% per year (a decrease). The aggregate average, however, is highly influenced by Maine, which saw prices fall by 20% following the opening of two new natural-gas supply pipelines from the Canadian Sable Island fields that were unrelated to electricity deregulation. Falling prices in Maine, therefore, cannot be attributed to increased competition in the electricity market. When Maine is removed, the "before" rate for the remaining five states was 0.8%, but industrial prices rose 2.0% after restructuring in those states. For comparison, regulated Vermont's prices rose 0.8% annually from 1990 through March 1998, and fell 0.8% from 2001-2003.

One overall way to examine the effect of deregulation is to compare the median annual rate of industrial price increase before and after restructuring for all the restructured states with the annual rate of price increase for the states that didn't restructure. In states which restructured, the median rate of annual price increase before restructuring was 0.1% per year compared to 1.3% per year after restructuring. For the states that didn't restructure, the median annual rate of price change in the period before the other states restructured was -0.7% compared with 0.5% for the period after the other states restructured. Finally, a regression analysis does not show a statistically significant difference between deregulated and regulated states in terms of industrial price changes over time.

3. Current Auction Structures are Problematic

With the exception of Texas, whose power market is based around bilateral transactions, a centralized spot market for electricity has been a defining feature of restructuring in the U.S. RTOs in the Northeast (New England, New York, and PJM) have created hourly and day-ahead spot markets that co-exist with longer-term bilateral markets; the Midwest ISO is scheduled to start up its spot market in 2006. The bids into these markets provide the basis for a centralized economic dispatch performed by the RTO. The Northeastern RTOs have acted on a regional basis in a way similar to the vertically-integrated utilities, but with generator bids, rather than generator costs, determining the dispatch order. California took the same approach in terms of a central auction market with the winning generators (those that were dispatched) paid the market clearing price for their power. However, California pressured the investor owned utilities to sell off their fossil generation and not sign any long-term supply contracts, thus funneling all transactions into the hourly and day-ahead markets.[11]

Why Centralized Auctions?

These market design choices were deliberate and intended to accomplish two goals. The first was to increase transparency in the market. Wholesale power trading began long before the 1998 opening of hourly spot markets in California and the PJM region; utilities had been trading "economy" energy among themselves for decades. The Energy Policy Act of 1992 opened the doors for non-utility parties to trade electricity on informal exchanges and the New York Mercantile Exchange (NYMEX) introduced its first electricity futures contracts in 1996. However, early power markets operated almost entirely on an over-the-counter basis, with many deals made bilaterally over the telephone. As such, information was hard to come by in the market, giving some players an advantage and hindering others. Trade publications such as the *Energy Market Report* began to publish power prices on a daily basis, but the reports were distributed long after each day's trading had ceased. In contrast, RTO spot markets report prices and distribute data in near-real time on public internet sites; this information can be obtained by anyone, not just generators or other market participants.

The second goal of the centralized spot market, particularly relevant in California where utilities were forced to divest generation assets, was to prevent opportunistic behavior associated with divestiture. A utility, for example, could sell off a power plant and then immediately sign a favorable long-term contract with the new plant owner. Without this provision, a California utility might have sold its generation on the basis of a long-term contract and never even participated in the hourly market, thus circumventing the attempt to make the market competitive.

Hourly Auctions Promote Tacit Collusion

Increasing market transparency and preventing “sham divestiture” should contribute to a more competitive electricity market. However, the hourly market structure adopted throughout the United States has had the unintended consequence of fostering tacit collusion among generators bidding into the auction. The Sherman Antitrust Act makes it a crime for companies to agree 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. The RTO practice of announcing its demand forecasts in advance of hourly auctions enables generators to bid strategically.

Unlike in other industries, market power in electricity auctions has relatively little to do with the market share of each company. The important variable is the relationship between the total demand for any hour, the amount of system generating capacity in excess of demand, and the amount of capacity controlled by each generator. A seller, faced with an announced amount of power that the RTO must buy, might be able to increase its profits by bidding high prices, effectively withholding needed capacity unless the RTO pays its price. If a generator had enough capacity so that withholding its generation would cause a blackout, it could dictate the price. This *pivotal supplier* problem can take the form of a single firm who could exercise pivotal power, or a group of firms colluding explicitly or implicitly. If the generating companies didn’t collude to raise the price, there is nothing illegal about colluding implicitly to withhold capacity by raising price.

A generator who interacts often with the same group of other generators in a market setting can learn the strategies of the other bidders. Sarosh Talukdar and his students have created a simulation with 10 firms, each having 10% of total system capacity. These simulated 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 in less than one hundred hours, as shown in the upper line of figure 1.[12] Stephen Rassenti, Vernon Smith, and Bart Wilson reach almost identical conclusions in an experimental setting.[13]

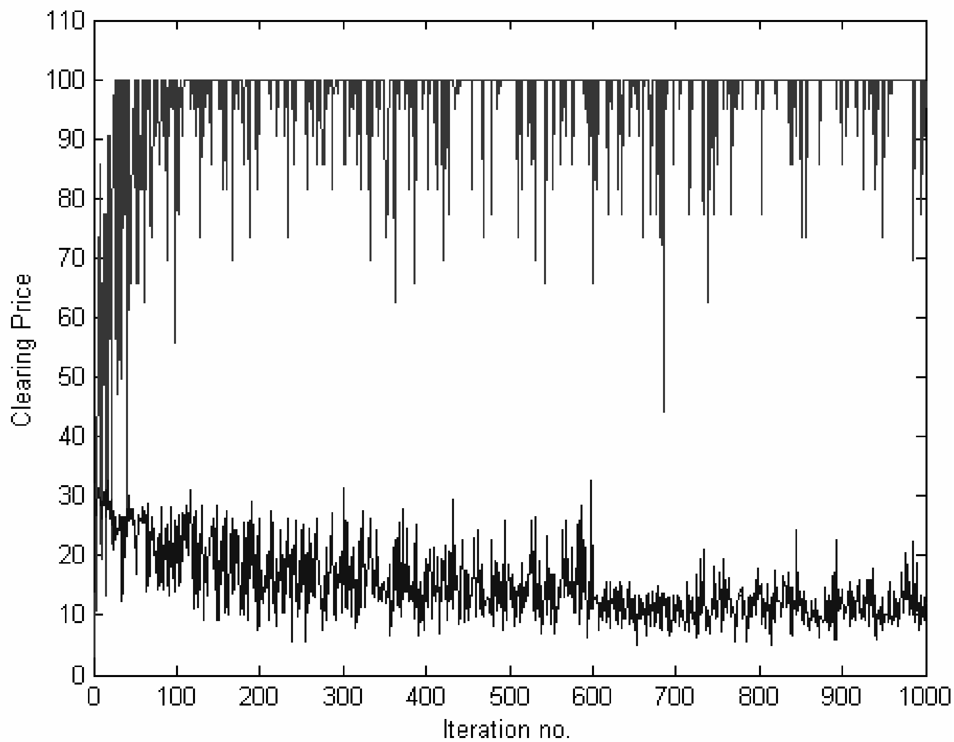

Figure 1. Electricity-market simulations show that tacit collusion is easy in frequently-repeated auctions, but price-responsive demand can curb monopoly pricing power. The upper line shows simulated auction prices with inelastic demand; the lower line shows simulated auction prices with active demand-side participation.

Seth Blumsack, Dmitri Perekhodtsev, and Lester Lave have examined the potential for pivotal suppliers to bid up auction prices in California, New York, and PJM during 2000 and 2001.[14] Their "pivotal supplier duration curve" is shown in figure 2. California's highly concentrated power market can be seen readily; a single generator could have exercised pivotal monopoly power nearly 10% of the time, and six firms acting in concert could have set the price every hour of the year. PJM and New York appear more competitive, but a group of six firms could have exerted pivotal power over 50% of the time.

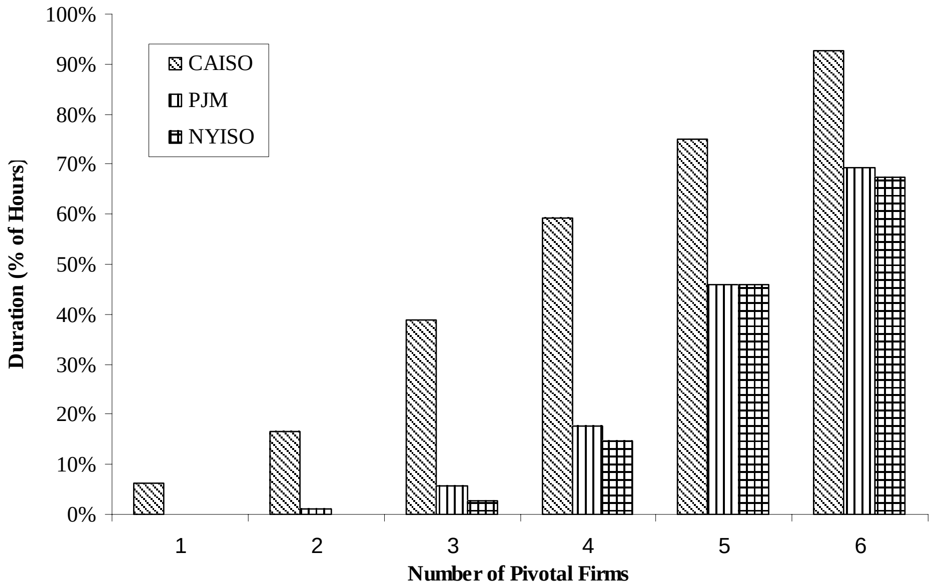

Figure 2. The number of pivotal firms in California, PJM, and New York, 2000 – 2001.

Current FERC and RTO market monitoring protocols recognize the pivotal supplier problem, but do not adequately handle the possibility that large numbers of firms could collude tacitly, raising prices in the auction. FERC's Standard Market Design proposed a pivotal supplier screening test that would check for pivotal monopolists, but not pivotal oligopoly.[15] PJM's State of the Market Reports show the number of hours in which one or two suppliers were pivotal, but no more than that.[16]

Mitigating pivotal suppliers to create free and competitive markets is possible if companies make investments in transmission or generation infrastructure that take away pivotal power status from the largest generators. Alternatively, large generating companies could be broken up so that no company controlled more than one large generator. Each of these steps entails significant additional costs.[17]

Seeking low prices that please consumers and regulators, the response of PJM and other RTOs to incidents of market manipulation has been to develop administered markets, where competitive prices prevail by decree, rather than through competition. PJM, in particular, imposes cost-based bidding on any generator dispatched out of merit order, and its market monitors have the authority to hand down fines to generators at any hint of impropriety.[18] Such closely-monitored RTO auctions may produce competitive prices, but they cannot be considered free or even deregulated markets. In effect, PJM is dispatching generators in merit order by cost during periods of high demand. It is only by substituting close monitoring by the RTO for PUC regulation that pivotal supplier market power has been kept in check.

Incomplete Markets

In addition to a competitive market for real power, a competitive electricity market requires that all parts of the market be competitive. That means that there must be competitive markets for regulation, spinning and non-spinning reserves, and reactive power. All current RTOs operate auctions for at least some ancillary services in addition to energy, and procure others at cost.[19] No RTO currently operates a market for reactive support. 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 straightforward. Reactive power is location-specific, since it attenuates with distance. The value of reserves depends on the location of the generating plant providing the reserves. Locational restrictions automatically raise market-power concerns. Automatic generation control (for frequency support) has historically been assigned to one plant in a given control area, and while multiple plants can bid into auctions for frequency support, the number is limited by technology (plants providing frequency support must have very quick ramp rates) and geographic restrictions (frequency support still must come from within the control area).

The Role of Inelastic Demand

Many competitiveness problems in modern electricity markets stem from the RTO assumption of a vertical demand curve (a behavior that is largely a legacy of the regulated era, in which monopoly utilities bore an “obligation to serve”). That is, the RTO announces its expected demand and then (through the hourly auction) solicits generator bids to fill that demand. 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 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.

In a restructured market where all generators are paid the market clearing price, assuming that demand is completely unresponsive to price leads to abnormally high prices and returns to baseload generators. If the market were competitive, the peak generators would never recover their fixed costs and the baseload generators would be overpaid. More importantly, a vertical demand schedule facilitates, even encourages, collusion to withhold generation and raise price. As simulations show (Fig. 1), generators facing a vertical demand curve learn to collude quickly, raising price. They also show that when the buyers are active in the market, they manage to keep prices low. In California, fixed retail prices and inelastic demand contributed to the bankruptcy of one of the state’s largest utilities, the near bankruptcy of two others, and rolling blackouts when the California ISO was faced with shortages.

Econometric studies suggest that a doubling of electricity prices would lead to consumers purchasing 7 – 20% less power, implying a short-run price elasticity of demand between –0.1 and –0.3.[20] Even with such a small amount of demand response, the effect on market prices would be significant, since peak generators have much higher marginal costs than shoulder or base load generators. In figure 1, the lower line represents the same set of market simulations run by Lye and Talukdar, but allowing for consumers to bid demand curves into the auction as well.[21] Initially, the generators attempt to exercise market power, but their ability to do so is quickly diminished by demand-side bidding.

Thus, for any electricity market to be successful, the demand side of the market must be as active a participant as the supply side. Otherwise the result will be extraordinarily high prices (as in California) or a "market" that must be so tightly controlled by the RTO that it resembles the integrated utility control of the regulated era (as in the Northeast). Some consumer groups are opposed to having customers face real prices, arguing that they are not able, or at least are unwilling, to deal with rapidly changing prices. Experience with other commodities, such as gasoline and airlines, suggests otherwise. Consumers are able to process rapidly-changing prices and make informed decisions. It is more difficult for consumers to react to electricity prices, since they purchase electricity on a continuous basis, rather than in discrete bundles as with gasoline, airline tickets, or hotel rooms. 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. Technology has existed for some time that allows utilities to remotely control devices in a consumer's home (with the consent of the consumer).[22] The barriers to demand-side response are almost entirely political.

4. Even Competitive Electricity Markets May Inherently Raise Costs

Even if the incentive problems associated with hourly auctions can be circumvented, getting to a competitive market structure often incurs large costs that can erase efficiency gains from deregulation. 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, deregulation rules like Standard Market Design (SMD) bring some inherent costs when they are implemented. Some of these costs are substantial.

Uniform Price Auction Structures

FERC's original standard market design, as well as every centralized auction currently operating in the United States, has a uniform-price structure. These markets (independent of contract markets) pay the market-clearing price for all megawatt-hours generated. If the auction is competitive, this market-clearing price is equal to the short-run marginal cost (MC) of the most expensive generator dispatched.

In a competitive market, all generators would bid their marginal cost for each unit. Under regulation, generators are paid their average (unit) costs (AC). At times of high demand 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. If prices are too low, even baseload units may have trouble recovering their capital costs. As a result, investors would be unwilling to build a new unit, particularly a peaker. 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, and such a system has been proposed for the United States. In the pay-as-bid auction, each successful auction participant is paid their bid, and not the bid of the marginal unit accepted into the auction. Theory and practice have shown that such a change would ultimately accomplish nothing. In practice, each market participant 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 substantial generation not 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.

New Institutions Are Costly

Deregulation requires new institutions, primarily to perform functions formerly carried out by vertically integrated utilities. Creating an effective new institution is expensive and time consuming. Start-up costs for the California ISO have been estimated as high as $1 billion and its budget is nearly $200 million per year. The budget for PJM is nearly $250 million per year.[23] On average, ISO operating costs amount to slightly less than one cent per kilowatt-hour.[24] The ISOs cover their operating costs through fees imposed on system participants and congestion payments. In Pennsylvania, a typical industrial user pays 0.22 ¢/kWh for grid management, seams elimination, and capacity payments, and an additional 0.4 ¢/kWh for load shaping.[25] Aside from the costs involved with formal institutions, market-based deregulation imposes costs on individual participants in the form of maintaining trading desks and gathering market information. Enron’s operating expenditures in 2000 to take part in the various energy markets (gas, oil, and electricity) were quoted at $449 million.[26] In a restructured market, firms must either assume these 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, meaning that costs will rise.[27] Regulators can require that retail prices fall (as they have for residential rates in many states), but these prices will not compensate for the additional costs and so, eventually, prices will have to reflect the higher costs.

Reliance on the Merchant Sector has Increased Risk

One explicit goal of regulation a century ago was to lower the risk associated with investment in utility industries.[28] Each year, demand would rise at a reasonably predictable rate, technology would improve, and real prices would fall. The lack of competition and the fact that rates of return were virtually guaranteed by regulation was a boon to utility stocks and bonds. Investors, seeing utilities as low-risk companies, were willing, ready, and eager to lend money to the electric power industry at very favorable rates.

Under rate-of-return regulation, the risks were borne by ratepayers. Under deregulation with fixed retail prices, the short-term risks have largely shifted to investors.[29] The uncertainty cannot be wished away. The median bond rating of investor-owned utilities prior to restructuring was “A”; after restructuring the median has fallen three grades to BBB. This is in sharp contrast to the 2003 bond ratings of public power (A+) and co-operatives (A), who are not subject to most of the uncertainty of restructuring.[30]

Intervention by regulators in California’s power crisis, uncertainty over the future course of regulation/deregulation, and the glut of natural gas generation has changed the way investors view the electricity industry and has needlessly increased the cost of capital. Investors have begun to demand higher rates of return, particularly from the merchant sector, and some investors are unwilling or unable to lend money at any rate. For the electric power industry, in which capital represents roughly two-thirds of the cost of generation equipment and nearly all of the cost of transmission lines, the result is that the total cost of new infrastructure has risen significantly.

Merchant generation and transmission is now viewed by the investment community as “project financing,” meaning that the revenues from the investment are the sole source of capital-cost recovery. Interest rates for project-financed investment are typically quite high: 15% to 20% and even higher. Such projects can be more difficult to fund because some require issuing B-grade debt, which some institutional investors (such as mutual funds) are prohibited from holding.[31]

Investments made by traditional vertically-integrated utilities (or municipal or federal agencies) are viewed as “system financing,” meaning that the recovery of capital costs could either occur through revenues from the investment or through some other source of cross-subsidization (such as revenue from customers, bond issuance, and so on). The financial community is willing to lend money to system-financed investments at much lower rates of around 10%.

Company	May 2001 Peak Share Price	April 15, 2005 Share Price	April 15, 2005 Credit Rating
AES	48.50	16.50	B+
AEP	50.40	34.19	BBB
Calpine	54.70	2.39	B-
Duke	46.10	27.89	BBB
El Paso	64.90	18.91	B-
Mirant	45.40	0.31	N/A
Reliant	33.80	10.91	B+
Southern Cos.	23.54	31.95	A-
Williams	41.00	16.55	B+

Table 3. Share prices and credit ratings for selected companies in the electric power sector.[32] On December 5, 2005, Calpine was de-listed from the New York Stock Exchange.

Equities markets have not been kind to deregulated utilities or the merchant sector; they have expressed their displeasure with the path of U.S. electricity restructuring by pricing the stock of utilities in states that have refused to restructure at a premium to that of utilities in states that have restructured. The stock of merchant generators has taken a real beating; the New York Stock Exchange de-listed Calpine on December 5, in anticipation of a bankruptcy filing. Table 3 shows the stock prices for several merchant generators and integrated utilities in 2001 (when power prices in California were still high) and 2005. Stock prices and credit ratings show this hierarchy of utilities in states that have not restructured being preferred to utilities in states that have restructured, since merchant firms bringing up the bottom. Given the emphasis that U.S. electric restructuring has placed on the role of the merchant sector to drive competition and investment, the numbers from the financial sector are not encouraging.

5. Impediments to Retail Competition

Benefits to consumers, largely in the form of lower prices but also in the form of new service offerings (particularly green power), were supposed to arrive through competition both at the wholesale level and at the retail level, except in low-demand states where markets are not easily contestable. California and Pennsylvania were initially the most aggressive states in allowing third-party electric-service providers (ESPs) to compete with utilities for individual customer accounts.

Large industrial customers were supposed to be the beneficiaries of retail competition. As noted previously, actual price data has shown no change in the price paid by the average industrial customer, or in the time rate of change of prices between industrial customers in restructured and un-restructured states. This average data masks some sharp changes, as large industrial customers with preferential contracts found themselves paying greatly increased rates as prices floated to market levels. In states such as Pennsylvania that forbid long-term bilateral contracts between a load-serving entity and a large industrial customer, rates for some very large customers went from 3.5 ¢/kWh before restructuring to 4.5 ¢/kWh in 2004, and will be driven to an estimated 6 ¢/kWh in 2007 as rising natural gas prices set the auction price in most hours. When stranded cost recovery is complete in 2010 and prices are free of regulation, some industry energy managers expect further increases.

Industrial rates are much less volatile in traditional regulated states, and an equity issue has arisen as firms actively consider moves to states with low and stable electricity prices. A further equity issue is that the consumers in generation-rich states such as Pennsylvania (that exports 31% of the power generated in the state) have paid stranded costs for generation assets that are used to produce power sold to other states, driving up the cost of power for in-state customers.

With a few exceptions, residential switching activity in the competitive retail market has been minimal at best. Even if residential consumers wanted to switch, many service areas simply don't have any competitors to the incumbent utility. Nineteen states currently offer some form of retail competition to at least some of its consumers, but in some areas (such as most of Pennsylvania) there are no alternatives to the incumbent utility.[33] Residential activity in competitive retail markets has been low, with the exception of some traditionally high-cost urban areas.[34] Commercial and large industrial customers have switched providers in somewhat higher numbers.

Pennsylvania provides an interesting case study illustrating the relative successes and failures of retail electric competition. Figures 3 and 4 show the percentage of load, by customer class, served by alternative suppliers in the service territories of Duquesne Light (serving the Pittsburgh area) and PECO (Philadelphia). Following an impressive start, switching activity in PECO's service territory fell to such meager levels that the state's public utility commission forced 20% of its customers to transfer to alternative ESPs.[35] Meanwhile, Duquesne Light has consistently seen roughly 20% of its load move to alternative ESPs. Despite the initially encouraging numbers, all alternative suppliers have pulled out of Pennsylvania as of November 2005 with the exception of those in PECO's service territory.[36]

In one sense low levels of switching activity in the residential sector is not surprising. With regional wholesale markets spanning large geographic areas, as in the Eastern and Western Interconnects, and with the centralized nature of many of these markets, both utilities and ESPs face the same market price for bulk power. Third-party electricity providers therefore must look to savings in labor and administrative costs, or to management economies of scale, to offer lower prices to potential new customers.

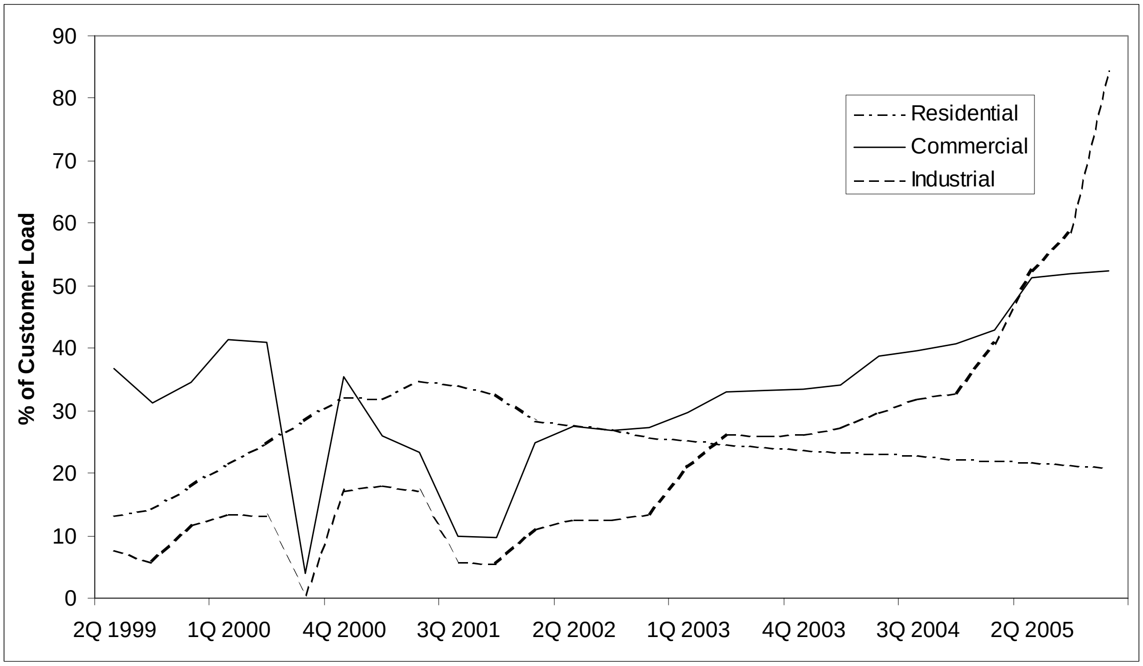

Figure 3. Consumer switching activity in the Duquesne Light service territory.

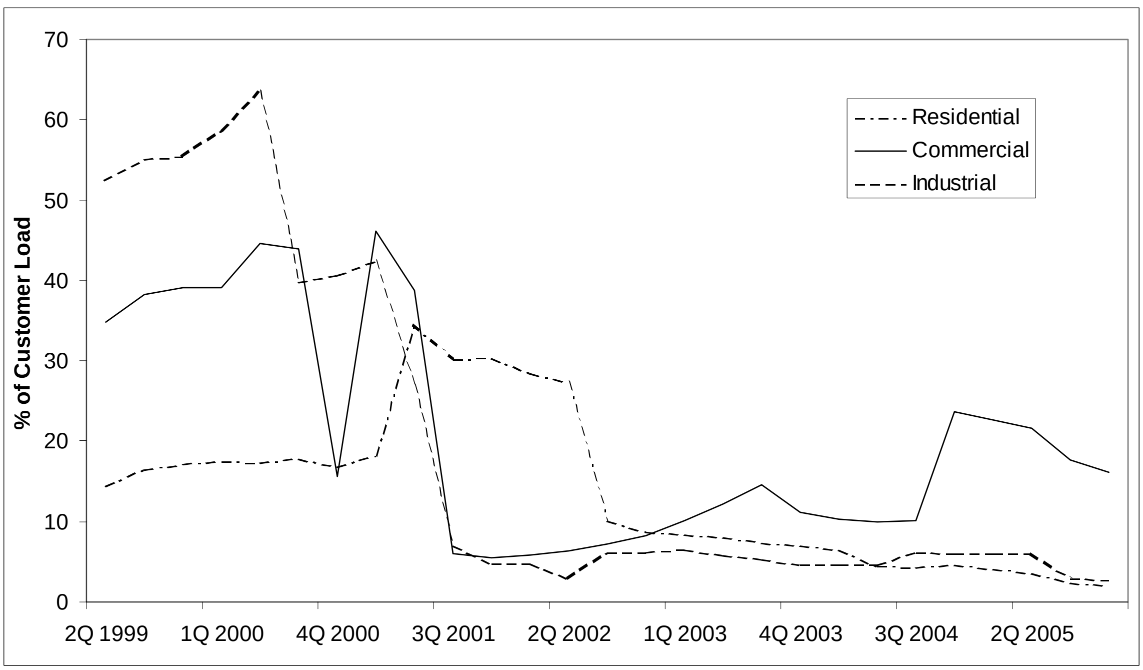

Figure 4. Consumer switching activity in the PECO service territory.

Particularly in the case of the residential sector, there appears to be little room for efficiency gains (and therefore vigorous price competition). Kenneth Rose reports[37] that residential consumers have saved approximately $0.9 billion since the inception of state retail competition programs (often due to mandated rate reductions, which are soon to expire, or subsidies given to consumers who switch, as happens in the Cleveland area). Total residential expenditures in 2003 amounted to over $110 billion.[38] Cumulative savings by residential consumers over several years has thus amounted to less than one percent of annual expenditures. Even these very small savings are likely to be erased once the mandated rate reductions and caps expire over the next few years.

In purely dollar amounts, the savings to individual residential customers is small, and may not be sufficient to overcome whatever search costs and switching costs consumers must bear. The result is that competitive ESPs have been leaving the market.

In some situations, distributed generation or micro-grids may represent an additional avenue for retail competition. For certain customers (such as those demanding ultra-high reliability or flexibility, or those who could benefit from combined heat and power applications), these smaller generation sources may be able to provide benefits that independent generators or traditional utilities cannot. Strictly speaking, installation of distributed generation is largely a private and unregulated decision; most distributed units are too small to be regulated in the same way as utility plants.[39]

Micro-grids, however, face various forms of discrimination in the regulatory arena. For many years, whether micro-grids could legally exist or connect to traditional utility distribution systems was questionable, since most states lacked a legal or regulatory distinction between a micro-grid and a public utility.[40] More recently, the notion of the exclusive utility service territory has been used to block the construction of micro-grids. In 1997, Pennsylvania Enterprises, Inc. sought an application to build a micro-grid at an industrial site in Northeastern Pennsylvania. Following arguments over whether the PEI micro-grid constituted a “public utility” (and thus could not infringe on the exclusive territory of the incumbent, Pennsylvania Power & Light), the state PUC allowed the PEI project to proceed, but additional legal challenges from the incumbent utility eventually forced the project’s investors to abandon the idea.

Many technical issues still exist with respect to distributed generation and micro-grids, chief among them interconnection protocols to allow distributed sources to connect to existing utility distribution and transmission networks. In May 2005, FERC issued Order 2006, which instructs that open-access tariffs be modified to include interconnection protocols and agreements for small distributed energy sources. The regulatory uncertainty still remains, although a productive start would be for FERC and individual states to formalize the definition of a micro-grid, and possibly require micro-grids to file tariffs in the same way that utilities must.[41]

6. The Transmission Puzzle

For an electricity market to be competitive, transmission must facilitate competition. Insufficient transmission will give certain generators locational market power, and will degrade reliability regardless of market structure or conduct. The increase in market transactions has stressed the power system noticeably, indirectly leading to lower reliability. Figure 5 shows the increase in transmission loading relief (TLR) actions over time.[42] In monetary terms, congestion costs in PJM alone rose from $53 million in 1999 to nearly $500 million in 2003.[43]

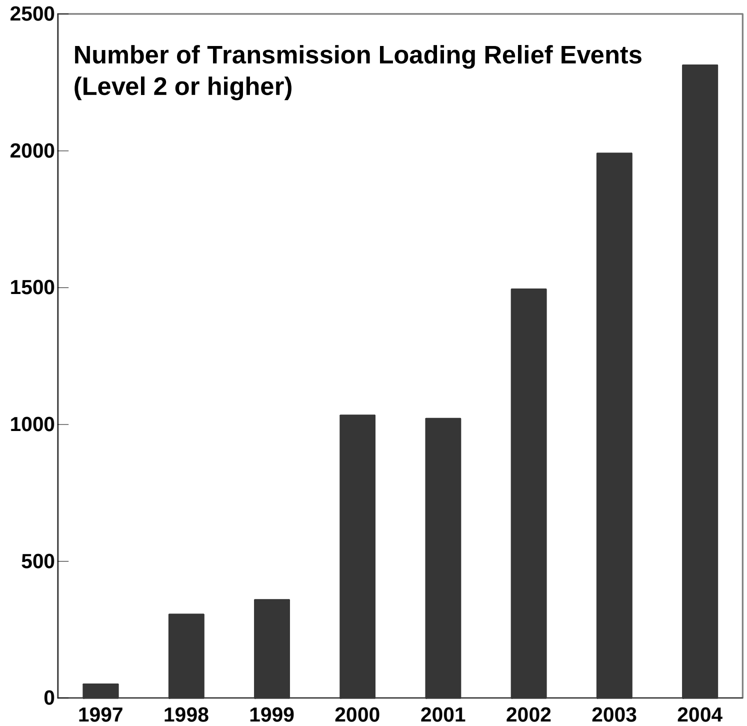

Figure 5. Transmission Loading Relief Events, 1997-2004.

As in the case of generation, prices must send longer-term signals to the market in the absence of planning. The architects of electricity industry reform originally hoped that a merchant transmission sector would emerge in the same way a merchant generation sector emerged with the passage of the Energy Policy Act of 1992.[44] Such a sector has not yet emerged, amid the financial problems faced by the broader merchant energy sector, as well as uncertainty over the profitability of investments. RTOs currently reward investors with transmission congestion contracts, which entitle investors to the financial flows arising from nodal price differences along the line.[45] However, this may give the owners of congested lines incentives to keep those lines congested (since the value of their congestion contracts would drop if congestion were relieved).[46]

Merchant transmission faces other problems apart from economics. New transmission lines can be built in such a way as to cause congestion in other parts of the system; the current system of rewarding investors with transmission contracts is also designed to punish those who modify the grid in detrimental ways (by "rewarding" the detrimental investment with a congestion contract of negative value). In simple networks such a scheme is remarkably efficient, but in complex and highly interconnected networks, the harm inflicted on the system is often not captured in the negative-value transmission contracts handed out by RTOs. Therefore, it may be possible for an independent transmission company to modify (or threaten to modify) the grid, and then charge some users to refrain from making the investment in the first place.[47]

Jay Apt and Lester Lave have argued that pricing of congestion gives the proper signals to users to transmit power at un-congested times, but provides disincentives to investors.[48] If the only payment is through congestion charges, no transmission owner would decrease his income by building a new line to relieve congestion. Prospective new builders would be discouraged, since the payments would decrease enough to put both the new and old owners out of business. The solution Apt and Lave propose is a two-part tariff: congestion charges would remain (at a lower level) to discourage congestion, and the bulk of payments would be through an energy charge that would provide incentives for new construction and efficient operation. The congestion and energy charges would collected by the RTO and paid to the transmission owners in a way that encouraged needed investment as well as the maintenance of the lines, thus removing the disincentive to construct new lines while still providing a disincentive to users who congest the line.

The U.S. experience has shown that in the restructured electricity environment, investments in needed transmission will occur only with the aid of political will. Even so, siting difficulty may pose such huge costs that incentives for investment may be further reduced or even eliminated. Investment in U.S. transmission has fallen at an average rate of $117 million per year in the past thirty years.[49] In the meantime, investment in generation has grown (see figure 6). Transmission projects with clear social benefits have taken years to complete or gain approval, such as the Path 15 expansion linking Northern and Southern California[50] or the Cross-Sound transmission line linking Southeastern Connecticut with Long Island.[51] Perhaps learning from the experience of New York, which could not get financing for a socially-beneficial transmission line linking Northern New York with New York City, the governors of four Western states have recently put their political muscle behind the construction of a high-voltage line linking coal-fired generation in the Rocky Mountains with demand centers in California.[52]

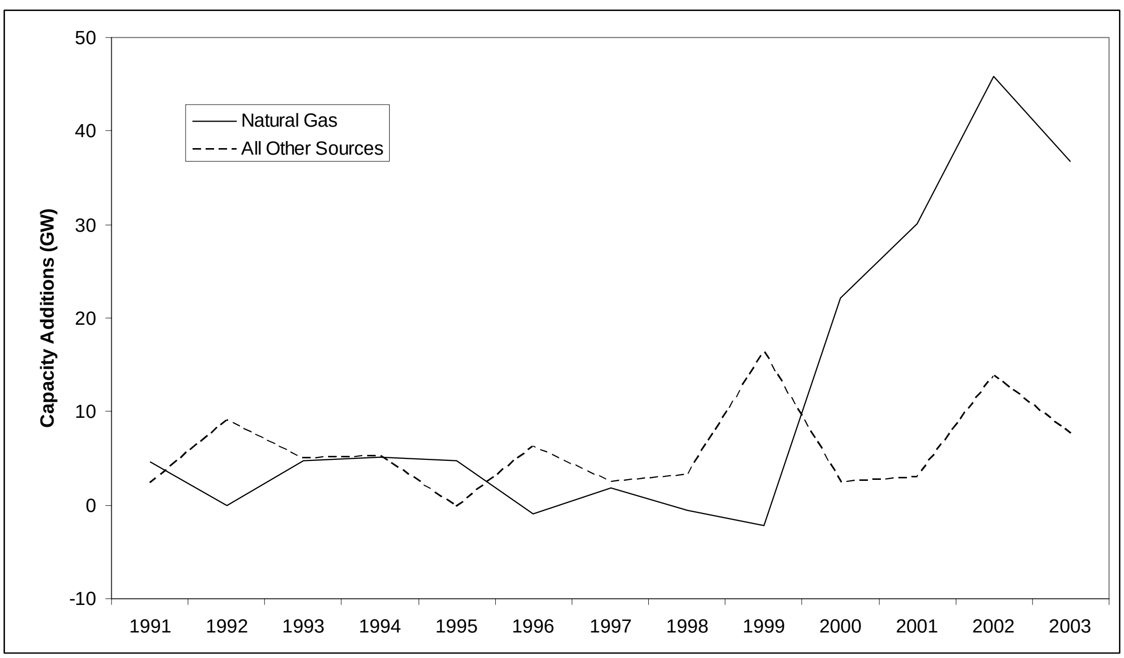

Figure 6. Generating capacity additions, 1991 – 2003.[53]

Despite the construction of a few high-profile projects in the past several years,[54] investment in the transmission grid has been anemic since the overbuilding in the 1970s. Rising congestion costs and transmission loading relief actions would seem to point to a clear need for investment. Shalini Vajjhala has analyzed the economic, social, and regulatory environment for transmission-grid investment in the U.S.[55] She finds that many states that need transmission investment most badly are also those that erect the largest barriers to investment. Figure 7 (used with Dr. Vajjhala's permission) shows a national picture of transmission demand and siting difficulty.

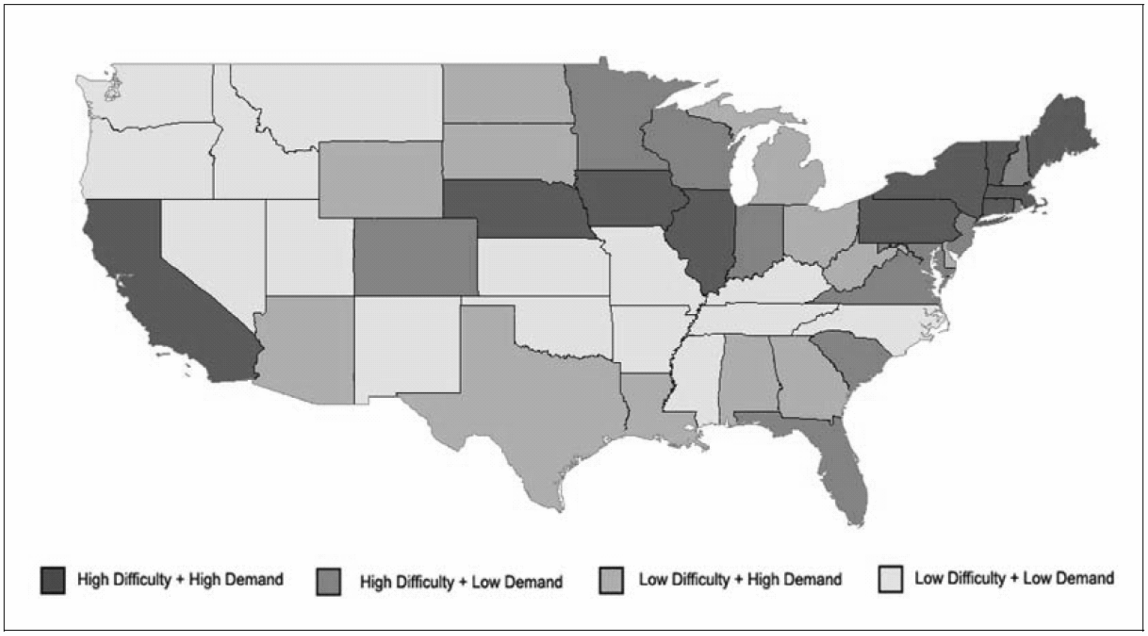

Figure 7. State transmission siting difficulty and transmission demand.

As a state characterized by Vajjhala as having high demand for new transmission and a high degree of difficulty in getting transmission sited, Pennsylvania provides a good case study for policymakers to gain a greater understanding of the social and regulatory impediments to investment in the transmission grid.[56] While the cost of electric generation in Pennsylvania is in line with the U.S. average, and much of Pennsylvania's population lives within close proximity of generation sources, the survey conducted by Vajjhala places Pennsylvania as the second-most difficult state for transmission siting by state regulatory officials.

RTOs could act as clearinghouses to streamline the siting and permitting processes for new transmission lines, potentially lowering the cost for interstate transmission projects. However, this would require giving FERC authority over the siting process, or at least the sharing of authority between FERC and state PUCs. Vajjhala notes that, "Our analyses show that there are large variations in existing transmission demand and levels of siting difficulty across states and regions. We believe that these variations will likely affect a state's (or utility's) incentive to join a specific RTO and result in unanticipated patterns of joining behavior and added interstate siting issues."[57]

7. Conclusion

A review of improvements in consumer welfare in other deregulated industries[58] concluded that substantial price reductions resulted from deregulation in airlines, trucking, railroads, and natural gas. The review notes that price reductions in real terms ranged from 30 to 75% in these industries.

No similar reductions have been observed in restructured electricity markets in the United States. The data show that prices for industrial customers, who were expected to be the principal beneficiaries, have no statistically significant differences between restructured and un-restructured states.

Residential consumers in restructured states such as Massachusetts are bracing for the expiration of mandated rate reductions and price caps: "NStar [on November 4, 2005] proposed raising rates by 25 to 34 percent for its residential customers in Boston and 80 suburbs starting Jan. 1, as it became the latest utility to seek price increases."[59] Retail competition for residential customers has all but disappeared. Except where regulated or subsidized, residential supplier switching is at very low levels, and alternative suppliers have exited formerly active retail markets, as in Western Pennsylvania.

FERC and the states should not be naïve in thinking that small changes in a regulated market, or in the restructured markets, will lead to the sort of vigorous competition that has characterized the deregulated airline, trucking, and telecommunications industries. The successful restructured markets rely on close monitoring and ordering generators to engage in behavior such as providing reactive power or providing electricity at cost. To step back to the level of monitoring and market intervention that characterize airlines, trucking, and other deregulated industries would require massive investments to increase generating and transmission capacity and breakup large generators into many small entities. FERC and the states need to recognize that a restructured electricity market would require close monitoring and frequent intervention to detect and punish the types of problems that arose in California.

Costs associated with ISOs and RTOs are real and significant. Those institutions have a costly responsibility: to prevent fraud and market abuse. Electricity is not like other restructured industries: a participant who misbehaves could cause a blackouts over wide portions of the grid. Those who wish to extend restructuring must weigh the benefits and costs, including these costs.

Since a substantial fraction of the cost of electric power is capital cost, those who wish to extend restructuring must first devise a mechanism that reduces the variability in return to investors, thereby reducing the cost to the consumer. This might take the form of a regulated monopoly, or the form of the mix of private risk and government loan guarantees proposed by William Rosenberg[60] for both regulated and deregulated states.

In uniform-price auctions, the total paid for electric power is higher than if baseload, shoulder, and peak generators were paid their individual costs. Pay-as-bid auctions will likely lead to the same result. In addition, hourly auctions provide ample opportunity for tacit collusion among pivotal suppliers, further raising costs. Any restructuring plan that is to benefit consumers must devise a combination of long-term and short-term instruments that result in average cost payments for each generation type.

For both restructured and traditional markets, innovations to provide price responsive demand are needed urgently. In restructured markets, demand elasticity can provide an excellent check on pivotal supplier market power. In traditional markets, it reduces peak loads and their associated cost and reliability issues.

Other opportunities for innovation may be enabled by legalizing micro-grids. In much the same way as the 1968 FCC decision in the Carterphone case enabled innovation in telecom, micro grids may provide venues for testing new business and technical models for the electric sector.

No satisfactory market mechanism has yet been established that properly compensates transmission owners for their infrastructure investment. Short of declaring transmission a public good like highways and locks on rivers, a two-part tariff for transmission might provide suitable incentives.

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. Even a competitive market that imposes large costs on market participants is unlikely to lead to lower prices.

Substituting markets for traditional regulation is only one choice among many policy instruments to achieve a goal of lower prices; such substitution should not be in itself a goal. Clear policy goals must be articulated, and periodic reviews conducted to assess which instrument is achieving the goals better.

Seth Blumsack *is a doctoral student in Engineering and Public Policy at Carnegie Mellon University.* ***Jay Apt*** *is Executive Director of the Carnegie Mellon Electricity Industry Center at the Tepper School of Business and the Department of Engineering and Public Policy, where he is a Distinguished Service Professor.* ***Lester B. Lave*** *is a University Professor at Carnegie Mellon University; The Harry B. and James H. Higgins Professor of Economics at CMU's Tepper School of Business; Professor in Engineering and Public Policy and in The H. John Heinz III School of Public Policy and Management; and co-Director of the Carnegie Mellon Electricity Industry Center.*

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Endnotes:

[1] Center for the Advancement of Energy Markets, 2003. *Estimating the Benefits of Restructuring Electricity Markets*, available at www.caem.org.
[2] ISO/RTO Council, "The Value of Regional Grid Operators," November 2005, available at http://www.nyiso.com.
[3] Paul Joskow, "Markets for Power: An Interim Assessment," *The Energy Journal* Vol. 27, No. 1 (2005), at 1-35.
[4] Cambridge Energy Research Associates, 2005. *Beyond the Crossroads: The Future Direction of Power Industry Restructuring*, 93pp.
[5] Jay Apt, "Competition Has Not Lowered US Industrial Electricity Prices", *The Electricity Journal*, Vol. 18, No. 2 (2005), at 52-61. Apt analyzes industrial electricity rates after accounting for seasonal periodicities.
[6] See section 4 of the review by Catherine Wolfram, "The Efficiency of Electricity Generation in the U.S. after Restructuring," Center for the Study of Energy Markets, University of California Energy Institute Working Paper No. 111, June 2003, available at http://www.ucei.berkeley.edu/PDF/csemwp111.pdf.
[7] Lester Lave, Jay Apt, and Seth Blumsack, 'Rethinking Electricity Deregulation', *The Electricity Journal*, Vol. 17, No. 8 (2004), at 11-26.
[8] Center for the Advancement of Energy Markets, *op cit.*
[9] Paul Joskow, "The Difficult Transition to Competitive Electricity Markets in the U.S.", in *Electricity Deregulation: Choices and Challenges*, James M. Griffin and Steven L. Puller, eds, University of Chicago Press (2005).
[10] Jay Apt, "Competition Has Not Lowered US Industrial Electricity Prices", *op cit.*
[11] California allowed the IOUs to retire their stranded-cost debt over a period of four years using a formula based upon the difference in the regulated retail price and the price of energy in the state's centralized spot market. Utilities seeking to recover stranded costs could engage in bilateral contracting, but the excess revenue from those purchases could not go towards retiring stranded costs, and any remaining stranded costs at the end of four years would remain on the books as debt. California's three large private utilities had such massive stranded costs that their clear incentive was to stick with the centralized spot market.
[12] Kong-Wei Lye, 2004. "Learning Agents in Power Markets", Ph.D. Dissertation, Department of Electrical and Computer Engineering, Carnegie Mellon University.
[13] Stephen Rassenti, Vernon Smith, and Bart Wilson, "Controlling Market Power an Price Spikes in Electricity Networks: Demand-Side Bidding," *Proceedings of the National Academy of Sciences,* Vol. 100, No. 5 (2003), at 2998 – 3003.
[14] Seth Blumsack, Dmitri Perekhodtsev, and Lester Lave "Market Power in Deregulated Wholesale Electricity Markets: Issues in Measurement and the Cost of Mitigation," *Electricity Journal*, Vol. 15, No. 9 (2002) at 11-24.
[15] 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.
[16] PJM's State of the Market Reports are produced annually and available at http://www.pjm.com.
[17] Seth Blumsack and Lester B. Lave, "Mitigating Market Power in Restructured U.S. Electricity Markets," *op cit.*
[18] PJM *State of the Markets Report 2004*, PJM Interconnection, LLC, available at http://www.pjm.com/markets/market-monitor/som.html.

[19] The New York and New England RTOs run auctions for all of their defined ancillary services except reactive support. See ISO/RTO Council, "The Value of Regional Grid Operators," November 2005, available at http://www.nyiso.com.
[20] Douglas Caves and Laurits Christensen, "Econometric Analysis of Residential Time-of-Use Electricity Pricing Experiments," *Journal of Econometrics* Vol. 14 (1980), at 287-306 and H.S. Houthakker, "Some Calculations of Electricity Consumption in Great Britain," *Journal of the Royal Statistical Society (A)*, Vol. 114, No. 3 (1951), at 351-371.
[21] Allowing consumers to bid into the auction is crucial. Economic theory readily demonstrates that monopolists can still elevate prices above competitive levels even if demand is price-responsive.
[22] F.C. Schweppe, et. al., "Homeostatic Utility Control," *IEEE Transactions on Power Apparatus and System*, Vol. PAS-99, No. 3 (1980) at 1151 – 1163.
[23] See Samuel van Vactor, *Flipping the Switch: The Transformation of Energy Markets*, Ph.D. dissertation (2004), University of Cambridge, and Margot Lutzenheiser, "A Comparative Analysis of ISO/RTO Operating Costs", available at http://www.ppcpdx.org/Tx/main2.html.
[24] ISO/RTO Council, "The Value of Regional Grid Operators," November 2005, available at http://www.nyiso.com.
[25] Table 4 in *Industrial Options for Large Electricity Customers in Western Pennsylvania*, Allegheny Conference on Community Development, Pittsburgh, Pennsylvania, 2005.
[26] Enron's financial reports are still available at http://www.enron.com. Although the manipulation 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.
[27] One estimate, by M. Scott Niederjohn ("Regulatory reform and labor outcomes in the U.S. electricity sector", *Monthly Labor Review*, Vol. 26, No. 5 (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.
[28] Richard F. Hirsh, Power Loss, MIT Press, Cambridge, 1999, 406pp.
[29] California shifted some of that risk back to ratepayers when retail rates were raised in the midst of the power crisis.
[30] Peter Murphy, *Standard & Poor's Power Rating Trends*, presentation at JP Morgan Public Power Conference, October 7, 2004, New York City.
[31] Gary Krellenstein, "Transmission Financing", paper delivered at Conference on Electricity Transmission and Distribution in Deregulated Markets, December 15-16, 2004, Pittsburgh, Pennsylvania, available at http://www.ece.cmu.edu/~tanddconf_2004/krellenstein-CMU.ppt.pdf.
[32] Standard and Poor's and Yahoo! Finance.
[33] Oregon currently offers some large consumers a choice of market-based or regulated rates. As of yet, none has signed up for market-based pricing.
[34] The biggest success in retail competition at the residential level would appear to be Ohio, where more than 60% of residential customers in the Cleveland area have switched electricity providers. However, as noted by Matthew Brown and Richard Sedano, "A Comprehensive View of U.S. Electricity Restructuring with Policy Options for the Future", National Council on Electricity Policy (2003), Electric Industry Restructuring Series, available at http://www.ncouncil.org, many customers in Ohio have received subsidized rates in exchange for switching.
[35] Under the Market Share Threshold Program (MST), PECO was obligated to find a lower-cost supplier for 20% of its customers. A smaller program, known as Competitive Discount Service (CDS), forced some consumers to give up PECO electric service for a third-party supplier chosen by the utility. The data in figure 4 does not include customers assigned to the MST or CDS programs.
[36] Pennsylvania Office of Consumer Advocate, *Electricity Shopping Guide*, November 2005. Available at http://www.oca.state.pa.us.
[37] "2003 Performance Review of Electric Power Markets", report for the Virginia State Corporation Commission.
[38] "Electric Power Annual 2003", Energy Information Administration, available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.
[39] Douglas King and M. Granger Morgan, "Guidance for Drafting State Legislation to Facilitate the Growth of Independent Electric Power Micro-Grids," Working Paper CEIC-03-17, Carnegie Mellon University, available at http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-03-17.asp.
[40] M. Granger Morgan and Hisham Zeriffi, "The Regulatory Environment for Small Independent Micro-Grid Companies," *Electricity Journal*, Vol. 15, No. 9 (2002),at 52 – 57.

[41] Douglas King, "The Regulatory Environment for Interconnected Electric Power Micro-Grids: Insights from State Officials," Working Paper CEIC-05-08, Carnegie Mellon University, available at http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-05-08.asp.
[42] North American Electric Reliability Council, available at ftp://www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm.
[43] *State of the Markets Report 2004*, PJM Interconnection, LLC, available at http://www.pjm.com/markets/market-monitor/som.html.
[44] See, for example, James Bushnell and Steven Stoft, "Electric Grid Investment Under a Contract Network Regime," *Journal of Regulatory Economics* Vol. 10 (1996), at 61 – 79.
[45] As originally suggested by William Hogan, "Contract Networks for Electric Power Transmission," *Journal of Regulatory Economics* Vol. 4 (1992), at 211 – 242. Note that the value of these contracts may be negative if the investor adds a line that is not beneficial to the system.
[46] Paul Joskow and Jean Tirole, "Merchant Transmission Investment," *Journal of Industrial Economics*, Vol. 53, No. 2 (2004), at 233-264.
[47] Whether or not these payments are economically efficient, they at least have the air of impropriety. For examples in which merchant transmission operators could extract payments or otherwise profit from harmful grid modifications, see Seth Blumsack, "Point-to-point Financial Transmission Rights and Network Topology," Working Paper, available at http://www.andrew.cmu.edu/~sblumsac/FTR.pdf.
[48] Jay Apt and Lester B. Lave, "Electric Gridlock: A National Solution", *Public Utilities Fortnightly*, Vol. 141, No. 18 (2003), at 14-16.
[49] Eric Hirst, "Key Transmission Planning Issues", *The Electricity Journal*, Vol. 14, No. 8 (2001), at 59–70.
[50] B. Hobbs et al. , 'The California ISO Transmission Economic Assessment Methodology', presented at Electricity Transmission in Deregulated Markets, Pittsburgh PA, December 2004, available at http://www.ece.cmu.edu/~tanddconf_2004/Hobbs_IEEE_TEAM.pdf.
[51] Gary Krellenstein, "Transmission Financing", *op cit.*
[52] Wyoming Public Service Commission, "The Frontier Line," available at http://psc.state.wy.us/htdocs/subregional/Frontierline040105.pdf
[53] *Energy Information Administration*
[54] Several highly-congested corridors in California, Texas, and the Southeastern U.S. have seen upgrades in recent years; see ISO/RTO Council, "The Value of Regional Grid Operators," November 2005, available at http://www.nyiso.com.
[55] Shalini Vajjhala, "Mapping Alternatives: Facilitating Citizen Participation in Development Planning and Environmental Decision Making," Ph.D. Dissertation, Carnegie Mellon University, July 2005.
[56] Jay Apt and Granger Morgan, "Critical Electric Power Issues in Pennsylvania," report for the Pennsylvania Office of Environmental Protection, July 2004, available at http://wpweb2k.gsia.cmu.edu/ceic/pdfs_other/Critical_Electric_Power_Issues_in_Pennsylvania.pdf.
[57] Shalini Vajjhala, "Mapping Alternatives: Facilitating Citizen Participation in Development Planning and Environmental Decision Making," *op cit.* PJM is a good example of this erratic type of RTO expansion; new membership from the Midwest has left PJM's territory geographically discontiguous.
[58] Clifford Winston, "U.S. Industry Adjustment to Economic Deregulation", *Journal of Economic Perspectives*, Vol. 12, No. 3 (1998) at 89-110, table 3.
[59] "NStar asks for major rate hikes," *The Boston Globe*, November 5, 2005.
[60] 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.