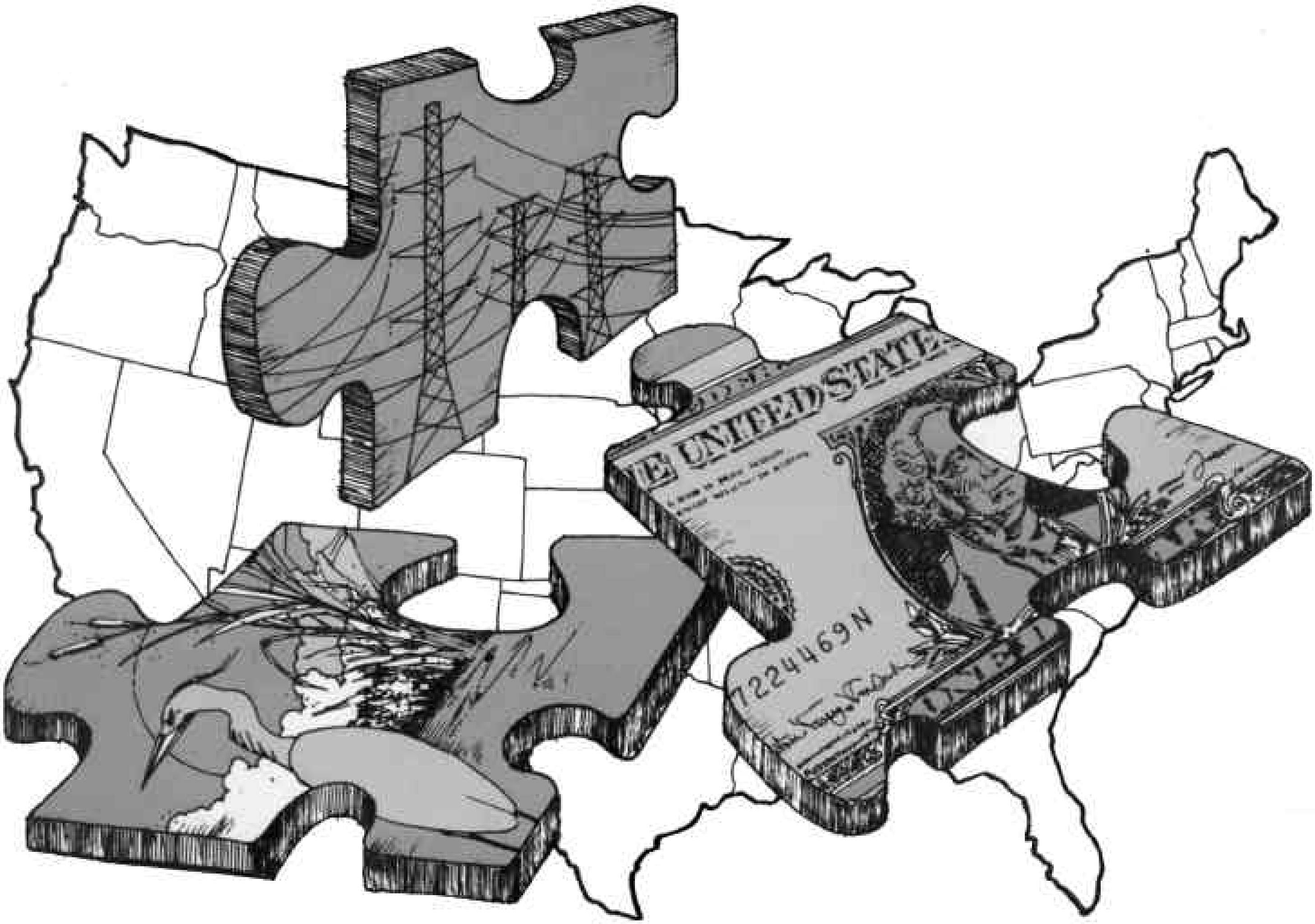
A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future



ELECTRIC INDUSTRY RESTRUCTURING SERIES

National Council on Electricity Policy

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A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future

The Electric Industry Restructuring Series

By
Matthew H. Brown
National Conference of State Legislatures
7700 East First Place
Denver, CO 80230
and
Richard P. Sedano
The Regulatory Assistance Project
50 State Street, Suite 3
Montpelier, VT 05602

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The Electric Industry Restructuring Series

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EXECUTIVE SUMMARY

When New Hampshire, Rhode Island, California and Pennsylvania became the first four states to open their retail power markets to competition, they began a trend that ultimately included nearly one-half of the states in the nation. Policymakers in these states sought to use competition to improve the economic climate in their states through lower electricity prices, to improve service for customers of major electric utilities, to promote innovation in the industry and in some cases to improve the environment.

At the same time that state policymakers commenced radical changes in the structure of the retail power industry in their states, federal policymakers embarked on a process designed to use competition to make the wholesale power markets more efficient.

These state and federal policymakers were responding to a host of political and technological factors when they decided to try to promote competition. Gas turbines had in the 1980s begun to offer a previously unmatched level of cost control and flexibility to the electric industry. As a result, many customers – especially the largest customers – argued that they should be freed from the high electric rates of the past. Such rates included charges for a series of choices that industry, state and federal policymakers had made that had ultimately increased electricity rates to what some considered intolerable levels. Information technology seemed to make it possible to adapt and adopt these new technologies as well. And finally, political forces prevalent in the 1990s suggested that competition and market forces would ultimately produce a more efficient result than would the hand of government regulation.

State and federal policymakers invented a host of new devices intended to bring market forces to the electric industry at all points, from generation to consumption.

Several years into the experiment with retail and wholesale competition, it is hard to make solid conclusions, although it is appropriate to make a number of preliminary ones. The experiences resulting from state and federal policies have led to the following results:

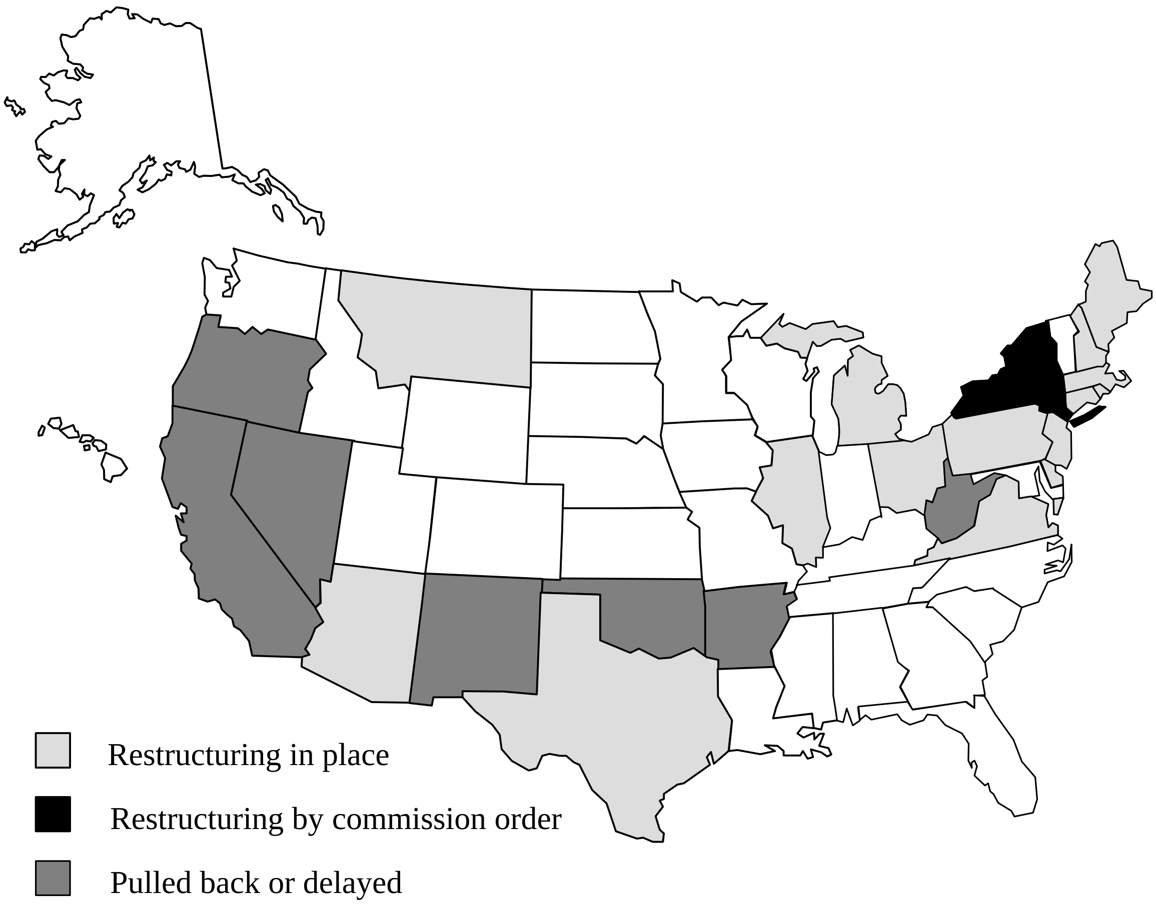
1. Retail competition has not for the most part provided a significant, direct benefit to any but the largest customers. The small customers have not participated in retail markets, nor have marketers chosen to market to those customers. In large part, this result is a function of the economics of the power market; the smallest customers do not use enough power to be attractive to power marketers, nor are the savings for most small customers significant enough to make it worthwhile for them to invest the time in researching and switching to new providers.
2. Wholesale competition has led to economic benefits, but both state and federal government officials have a significant role to play in making wholesale markets work better.
3. To a large extent, the major goals of wholesale and retail competition are still elusive. Most customers still pay regulated rates, the industry now faces growing concern for underinvestment in transmission infrastructure alongside a glut of generation, customer resources are under-utilized, wholesale electricity rates have been volatile over the past five years and in some parts of the country retail rates have risen as well. The impact of competition on the environment is yet inconclusive.

State policymakers now face a series of choices, especially as transitional protections such as rate caps and rate freezes begin to expire. These policy choices fall into five categories:

1. **Encourage choice.** Redesign the system to either offer financial incentives to people who switch from regulated suppliers or raise the prices for people who do not switch such that they see economic value in switching. Make switching easier. Experiment with real time pricing with some retail customers.
2. **Go slow.** At least for a while, small customers are not likely to switch. Find policy approaches tailored to the needs of small customers that bring benefits of competition but leave in place the protections of regulation. These approaches might best be classified as hybrids of regulation and competition. Apply lessons learned from restructuring even if retail competition is not permitted. Do not rush ending default service.
3. **Go back.** Decide that a truly competitive market is not achievable, at least in the near term, so reverse plans for retail competition and restore the vertically integrated utility.
4. **Government steps in.** Step back entirely from the idea of a competitive retail market and, instead, explore ways for the government to be directly involved in the procurement and sale of electricity.
5. **Transmission and public interest policies.** There are several practices and policies that offer consumer benefits independent of the state of competition, or the way the industry in organized. While the environment of change has sparked these innovations, they may apply in both competitive and monopoly states.

This report concludes that there is an urgent need for state policymakers to develop long-term and coordinated plans for the electric industry. However, each state faces unique circumstances that require individualized solutions. This report does not recommend specific solutions, since circumstances will vary a great deal in each state. State policymakers must however work together and with their federal counterparts as the electric industry becomes more regional.

Figure 1: Status of State Electric Industry Restructuring Activity as of December 2002



Source: National Conference of State Legislatures

INTRODUCTION

At this point, is a review of electric industry restructuring in the United States like the story of *Gone With The Wind*, or is it more like *The Miracle Worker*? Is it the story of an unruly destruction of an archaic system, replacing it with one that has many faults of its own? Or is it an inevitable though difficult improvement of a system through hard work, ingenuity and some technology? There remain many questions about electric industry restructuring.

A report of this kind is ambitious by nature, and we want to thank the reader for giving us this chance to work through the subject, whichever dramatic perspective you bring to it. Please make use of the Table of Contents to help navigate this substantial work.

Recounting the electric restructuring story is valuable because it helps policymakers make the further decisions to advance, retreat, or change course. Many will view the most important part of this report, then, as the Policy Options section. In considering the policy options offered here, it is well to consider how much is unknown about the future. Many costly policy forays can be traced to over-confidence about the predictability of the future. Unexpected events have a way of disrupting seemingly well-conceived strategies for both regulators and market participants.

The National Council on Electricity Policy stands for open discussion of important matter among state legislators, state regulators, state executive branch energy officials, and federal policy officials. The full opus of reports sponsored by the National Council can be found at http://www.ncouncil.org.

I. THE GOALS OF ELECTRIC INDUSTRY RESTRUCTURING

The movement to restructure the electric industry in the United States has dominated the attention of utility policymakers since the early 1990s. This report documents the performance and outcomes of restructuring in the U.S. and offers perspectives on policies that build on the first few years of experience with restructured markets.

Electric restructuring focused on two areas: **retail markets** and **wholesale markets**. State policymakers retained primary responsibility for retail markets, defined as the sale of power directly to retail customers such as a house or a supermarket. State policymakers focus on whether or not to give retail electricity consumers the chance to choose their electricity provider and how to regulate retail electricity markets.

Both federal and state policymakers try to find ways to create robust competition in wholesale electricity markets. Wholesale markets consist of large interconnected systems of power lines and power plants owned by many companies. The federal government retains primary responsibility for wholesale power markets across all states except Texas, Hawaii and Alaska.[1] State and federal policymakers both focus on finding ways to enhance competition in wholesale markets through equal and open access to the power grid and common rules across jurisdictions.

Restructuring of either wholesale or retail markets does not mean deregulation. Restructuring changes rules and the nature or intensity of regulation, but regulation does not disappear. Restructuring is a far more apt term.

At the outset, it is appropriate to look to the beginning of the debate for a reminder of the original goals of restructuring. **Lower-priced electricity** was the most popular goal of electric restructuring advocates, but not the only one. Other primary goals included **better service**, **improved innovation**, and, for some advocates, **improved environmental quality**. The following section describes these goals in greater detail. The section is designed to describe the goals and the justification that advocates of competition set out for the goals. Some of these goals were based on realistic assumptions, others based on assumptions and hopes that may have been too optimistic.

GOAL 1: LOWER PRICED ELECTRICITY

Most lawmakers who voted to allow retail competition were convinced that electric rates would fall in restructured markets.[2] Advocates of competition attacked high rates in order to encourage legislatures to address retail electric competition, warning legislators that failure to use retail competition to reduce rates would give the state a poor image in the business community. They pointed to the large disparity among rates across the U.S. and even within individual states and

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[1] Federal regulation addresses inter-state commerce. Alaska and Hawaii are isolated from the Lower 48 States. Texas is largely exempt because it is not connected electrically to surrounding states with free-flowing AC lines. What connections there are are DC converters – electric gates that can be easily closed. Figure 2 illustrates the distinct interconnection that serves most of Texas.

[2] Some prefer to focus on electric bills, rather than rates, reasoning that the size of bills is what affects consumers' pocketbooks and that bills reflect system efficiency. Rates, however, are easier to compare.

regions. Average electric rates in low cost states were less than half those of higher cost states.[3] Advocates pointed to new, lower cost power sources that offered the promise of lower retail rates, though this promise could be delayed by decades because utility rates still had embedded within them the cost of older, more expensive generation.[4] They also presumed that waste could be excised from utility operations.

Business Rate Discounts in Monopoly States

Before the first state adopted retail competition, larger customers were already winning lower rates. "Economic development" rate agreements, or "load retention" rate agreements became an issue of growing importance in many states.

Economic development rates present a trade-off between the interests of fairness among ratepayers and state economic development. A customer, typically a manufacturer, would tell state and utility officials that it would locate a facility in a given location, or make a significant expansion at an existing facility, if certain conditions were met by both sides. These conditions for the customer typically included a commitment to provide a minimum number of jobs, to employ energy efficient measures, and to stay for a minimum period. Customers sometimes had to make a "but for" declaration, that "but for" an electric rate concession, the expansion or the new facility would not occur.

Along with other incentives for the customer (tax stabilization, tax credits, etc.) a discounted electric rate would typically be above the marginal cost to produce and deliver this power, but 10-50% below retail rates. Generally, the discount would be for a limited number of years. States that used this device recognized that while these rates were special and could cause resentment among other customers, the public was not being harmed since revenue from the new energy use was covering its marginal cost, the cost to produce it. In this way states said economic development rates were sufficiently fair to pass regulatory muster.

Load retention rates present a more difficult policy choice. In this case, the customer offers nothing except the threat to move an existing operation elsewhere. The state is put in the difficult position of making a counter-offer to keep the customer and the jobs in the state. Because the revenue from existing load is reduced in a load retention rate, other customers must make up the difference consistent with normal utility cost recovery practices.

Some advocates for restructuring cited these situations as examples that the largest power users were already getting competitive benefits, and more sweeping changes were needed to make these opportunities available to all customers. According to one competition supporter in late 1995, "[T]he failure to make a reasonable transition to retail customer choice will cause the very shifting of costs to captive ratepayers that some opponents of retail choice fear most."[5]

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[3] In 1994 when electric restructuring policy development began in earnest in many states, the average rate in New Hampshire was 11.3 cents per kWh. Average rates Washington were 3.7 cents per kWh. The U.S. average was 6.9 cents per kWh. Electric Power Annual 1994, U.S. Department of Energy, Energy Information Administration, 1995.

[4] If utility costs are not borne by ratepayers, they would likely be shared by shareholders and taxpayers.

[5] Hanger, John, ELCON 1995 Fall Seminar, October 19, 1995. Hanger was a commissioner with the Pennsylvania Public Utility Commission.

GOAL 2: BETTER SERVICE

Some advocates of retail competition suggested that monopoly utility service quality would improve under competition. These advocates cited examples of customer service centers that did not answer calls, or did so after too many rings; customer service agents who were uninformed or unhelpful; incomprehensible bills; and poor service quality (too many distribution maintenance outages, delayed restoration of service after outages). In addition, some customers wanted to buy power derived from sources, such as renewable energy, that they considered clean, but had no way to purchase through their utility. Collectively, these advocates of retail competition suggested that utilities made little or no effort to determine the different services and products customers might want, nor did they make a meaningful effort to deliver them. Utilities, for their part, had little incentive to provide exemplary service.

GOAL 3: SPUR INNOVATION

Advocates suggested that competition would spur innovation in the electric industry. Some critics tagged regulation with responsibility for a declining utility record in innovation. Traditional, regulation seemed to reward replacing and expanding the power system with traditional, not innovative technologies. At the same time, regulatory commissions that did not allow utilities to recover some of their investments in expensive nuclear units – and resulting write-offs – chilled the utility appetite for taking chances.

Advocates of competition saw it as a way to spur innovation in several ways:

- A new fleet of highly efficient natural gas fired power plants would replace the older and less efficient generating facilities. Generators would compete on price and performance (efficiency, availability).

- Grid operators would deploy a host of new research and development technology and information systems on transmission and distribution to make the nation's grid of power lines operate more efficiently.

- Marketers would offer a host of new products supported by new information technologies that would encourage customers to be more efficient, to better respond to conditions in wholesale markets, to take advantage of new products to better meet their needs and to take advantage of ways to reduce their overall power costs.

GOAL 4: IMPROVE THE ENVIRONMENT

Some environmental advocates offered two reasons for supporting restructuring: accelerating the deployment of cleaner power, and enabling consumers to select cleaner power supplies.

Some environmental advocates[6] embraced restructuring as a way to accelerate the deployment of efficient and low-emitting generation. New generation technology promised to lower emissions

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[6] Trublood, David, *A Bold Collaboration Brings More and Greener Power to New England*. Conservation Matters, Journal of the Conservation Law Foundation Summer 2001, Volume 8. "For CLF, these (nine clean burning combined cycle plants that have been completed in New England in the past two years) represent a reward for years of strategic effort in which CLF worked to reinvent the way electrical power is organized and produced in New England."

of acid rain and ozone precursors, SO_x and NO_x. These power plants also emit lower levels of toxics, mercury, and particulates than the older power plants.

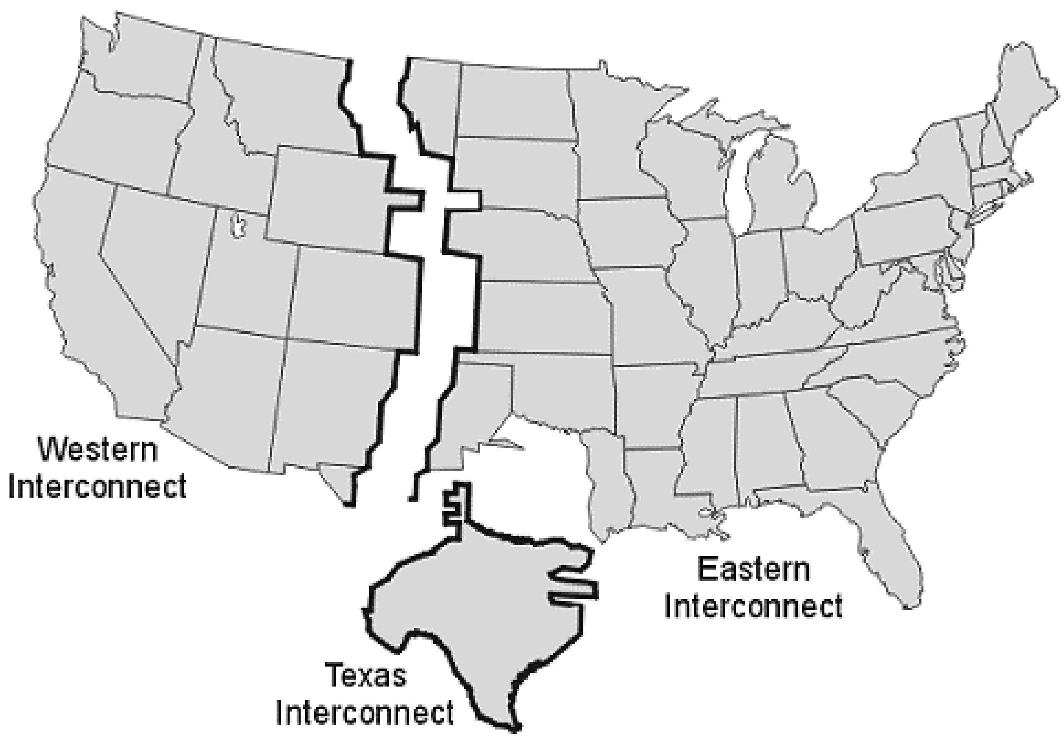
Environmental advocates also suggested that retail choice offered the chance for consumers to choose “green”, “environmentally–friendly” products instead of power generated from traditional sources, creating demand for and promoting the construction of more sustainable electricity supplies, including resources on the customer side of the meter.

Not all environmental advocates welcomed restructuring. Environmental groups that opposed restructuring questioned whether customers would really make environmentally driven choices especially if they cost too much. They also worried that the expanded geography of interstate electricity markets would improve the ability of energy from inefficient and highly polluting energy stations to find economically driven customers several states away.

Another concern was the prospect that proliferation of customer-owned generation might take the form of polluting diesel engines, rather than cleaner systems, creating a new air quality challenge.

In the next section, this report examines the complex and challenging issues, including counter-arguments to the assertions recited here, that awaited policymakers and advocates as they began the debate over electric restructuring.

Figure 2: The United States Power Grid, Showing Three Distinct Interconnections [1]



[1] The Eastern and Western Interconnects also include large areas of Canada, not shown.

Source: U.S. Department of Energy

II. POLICYMAKERS PURSUE RESTRUCTURING

By 1995, a majority of state legislatures recognized that electric industry restructuring was a political issue that they would soon have to face. The forces advocating for change were strong. They included large customers looking for lower prices, power marketers looking for business opportunities, and in some cases, electric utilities hoping for higher earnings. Free market advocates supported these industry advocates. And although no federal law ever forced states to allow retail competition, the threat of federal action loomed in the background of state policy deliberations. This section reviews the historical events and problems that led policymakers and advocates to consider competition.

A. BACKGROUND – STABLE REGULATION BUILDS THE U.S. ELECTRIC INDUSTRY, THEN COMES UNDONE

Anti-trust regulation and political maneuvering in the early 20th Century led to the U.S. electric utility structure which has been in place for the rest of the century. States granted companies a monopoly within discrete geographic areas, or service territories. The companies accepted the opportunity to earn a preset rate of return on investment in the service territory, in addition to the expectation of recovering their necessary costs, assuming that state regulators deemed those costs to have been prudent and reasonable.[7]

Investor-owned utilities' earnings would flow from an allowed (but not certain) return on investment, and regulators would set the return to be sufficient to attract and maintain a flow of capital to the firm under normal circumstances.[8] [9]A typical regulated return on equity investment today is around 10-12 percent, and this rises and falls based on a number of arcane factors including long-term interest rates and investor expectations. This relationship provided a foundation for a stable flow of capital from financial markets to fund the construction of the remarkable national electric system the United States now has.

By the end of the 1970s, though, the regulated system of monopolies allowed rates to climb, particularly in the northeastern United States, parts of the Midwest and the far West. Ultimately, these high rates prompted some consumers to build their own power supplies and led many in the industry as well as policymakers to think about the idea of competition. These rates had climbed – pointing to apparent inefficiencies in the regulatory system itself – for several reasons.

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[7] Bonbright, James C., Albert L. Danielson, David Kamerschen, *Principles of Public Utility Rates*, 2nd Edition 1982 Public Utilities Reports p. 109.

[8] While the allowed rate of return can be adjusted based on utility performance against some preset public interest standards, this is rarely done. More often, but still rare, the return is reduced as a penalty in response to imprudent behavior.

[9] There is a range of views about how much risk the utility is fairly taking on in return for the allowed return on equity investment. Some apply a strict rule that events for which the utility has no control are not really covered by the risk associated with the ROE, so when these events occur, the utility is entitled to pass the resulting costs to consumers. Others apply a broader view of reasonable risk, suggesting that reasonable risks include the changing of the regulatory regime. Some policymakers incorrectly think of the allowed return on investment as an entitlement. One advocate of stranded cost sharing explained his view this way, "Utility shareholders accepted risk when they invested – that's what risk-adjusted rate of return is all about." John Anderson, ELCONREPORT No. 3, 1996.

Investments in Expensive Power Generation

Utilities invested in increasingly larger power plants from the 1960s into the early 1980s. The size of individual units' rose from 300-500 megawatts (MW) to over 1,000 MW. This trend toward large power units and substantial capital investments in each one resulted from technology and economies of scale at the time. These factors made it less expensive on a per MegaWatt basis to build larger power plants. Industry also invested in nuclear power during the 1970s. These stations had particularly high capital costs, while their variable operating costs were designed to be low. Many observers began to worry that costs – and accountability for these costs – had spiraled out of control.

In the midst of this construction boom, oil prices spiked, prompting energy conservation, and independent power producers began to intrude on the utilities' monopoly. These trends in concert with high capital costs of utility construction put upward pressure on rates.

A Simple Utility Cost of Service

Operating Costs (includes power, operating & maintenance, administrative & general, and transmission & distribution)		$100,000,000	
Rate Base (Book Value of Depreciated Value of Assets)	$30,000,000		
Allowed Rate of Return on Investment	11%		
Return on Investment		$3,300,000	
Total Utility Revenue Requirement		$103,300,000	
Test Year Sales		1,000,000,000	kWh
Rate		10.33	cents per kWh,
Or		$103.3	per MWh

The near-disaster in 1979 at the Three Mile Island nuclear station in Pennsylvania amplified these concerns, and had the effect of pushing costs up still higher when regulators redefined and elevated the appropriate level of safety. Some nuclear facilities suffered regulatory and operational problems that left them out of service for months at a time or kept them from ever starting up -- always at tremendous cost. One prominent example was the Shoreham nuclear facility on Long Island, which operated just a few hours, and then was shut down.[10] Another was the Seabrook facility in New Hampshire, which was under construction for 14 years with only one of its two units completed. High costs for both these facilities were responsible for bankruptcy and high electricity rates at the Long Island Lighting Company (LILCO) and Public Service New Hampshire (PSNH). Very high interest rates at the time of substantial capital commitments added to the stress.

[10] Nuclear facilities have in recent years been operating much more reliably and for a greater percentage of the hours in a year. This improvement has contributed to the increased market value of nuclear units. Nuclear facilities that initially were selling in 1998 for approximately $65 per kilowatt are selling in 2000 for approximately $600 per kilowatt. (Source: *Global Energy Business vol. 2, no. 6 November/December 2000.*)

Contracts That Utilities Signed with Independent Generators

Also in the 1970s, the United States faced two oil embargoes and fuel prices shot upwards. Many state governments as well as the federal government reacted by trying to find new ways to encourage domestic energy production. In this context the federal government enacted the Public Utility Regulatory Policies Act (PURPA) of 1978. The U.S. Congress passed PURPA in an effort to diversify the nation's mix of fuels used to generate power. PURPA had the effect of creating an entirely new segment of the power industry that built and operated power plants exclusively to sell power to utilities. The law required utilities to grant transmission access to and buy power under certain conditions from these independently-owned generators known alternatively as an independent power producer (IPP), non-utility generator (NUG) or qualifying facility (QFs). [11] These companies signed long-term contracts to supply power to utilities at rates specified by regulation. These rates were based on forecasted costs to utilities of new generation that would be avoided.

Because IPPs generally relied on project financing from banks, they required long-term power sales agreements to support their financing.[12] While the IPPs' needs were superficially distinct from the utilities own power investments, the fundamental similarity is that both needed a sound financial footing to attract capital. Often, contract prices were fixed for 20 years or more. To further help these small power generators raise the money they needed to build their plants, some contracts were "front loaded," meaning that the utility paid a particularly high price for power during the early years of the power sales agreement, and would later pay a lower price. Pricing for these long-term contracts was based on the best estimate at the time of future energy prices. Many of these contracts were signed during the 1980s—a time of rising energy prices—under the assumption that energy prices would continue to rise. As a result, many utilities signed contracts with generators to supply power for more than 10 cents per kilowatt-hour (kWh).

From the early 1980s into the early 1990s the independent power generators were building an increasing proportion of all power plants. While some of these were hydro-electric or biomass-fired facilities, many of these new generators were using relatively low capital cost natural gas fired generators to produce electricity. The PURPA-based contracts that utilities signed with independent generators also ended up encouraging the move to competition.

Numerous states enacted similar state versions of PURPA, sometimes known as mini-PURPA. In New York, the law specified that all qualifying contracts would be for at least 6 cents per kilowatt-hour. New Hampshire utilities signed contracts based on the utilities' own high cost generation, which were as much as 12 cents per kilowatt-hour or more. Figure 3 shows that the states with particularly high levels of non-utility generation closely track those states with high rates.

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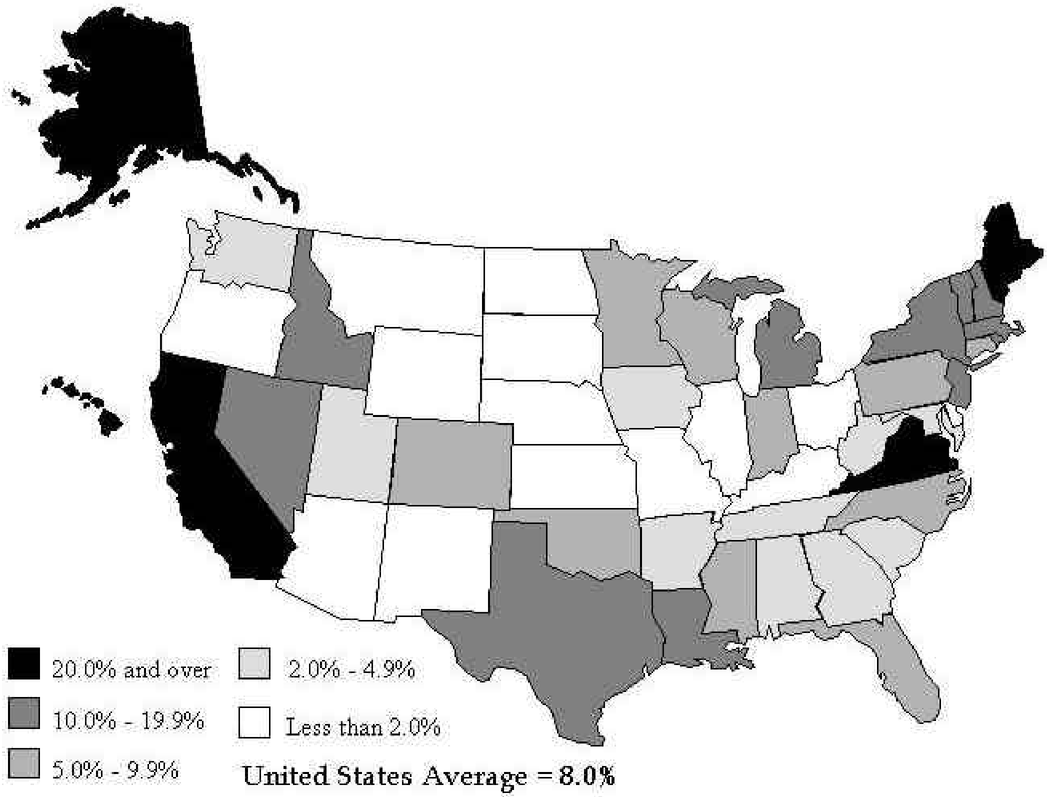
[11] Generators qualified to have utilities purchase their output if either they were renewable and less than 80 MW, or if they were a cogeneration system with at least 5 percent of energy production serving the industrial host. The latter category is the source of the majority of MegaWatts. PURPA can be credited, however, with spurring development and deployment of a significant amount of renewable technology in use today.

[12] Project financing means that the entire capacity to repay debt flows from project revenues. Owners are insulated from financial risk beyond their equity interest in the project.

Figure 3. Non-Utility Electric Generation Capacity by State as a Percent of Each State's Total Capacity – December 31, 1994



Source: The National Conference of State Legislatures.

When wholesale electricity rates fell in the 1990s, these contracts appeared to be unwise investments. However, at the time they were signed, —and given the expectation at the time of high energy prices—they looked reasonable.

In 1992, the U.S. Congress enacted the Energy Policy Act of 1992. In it a new category of independent power producer, the exempt wholesale generator (EWG), was created. An EWG could use any fuel, and could be of any size. While it was not entitled to avoided cost rates, it was entitled to "market-based" rates, meaning it could compete regardless of its costs. This development accelerated the creation of new wholesale markets and the rules needed to govern them.

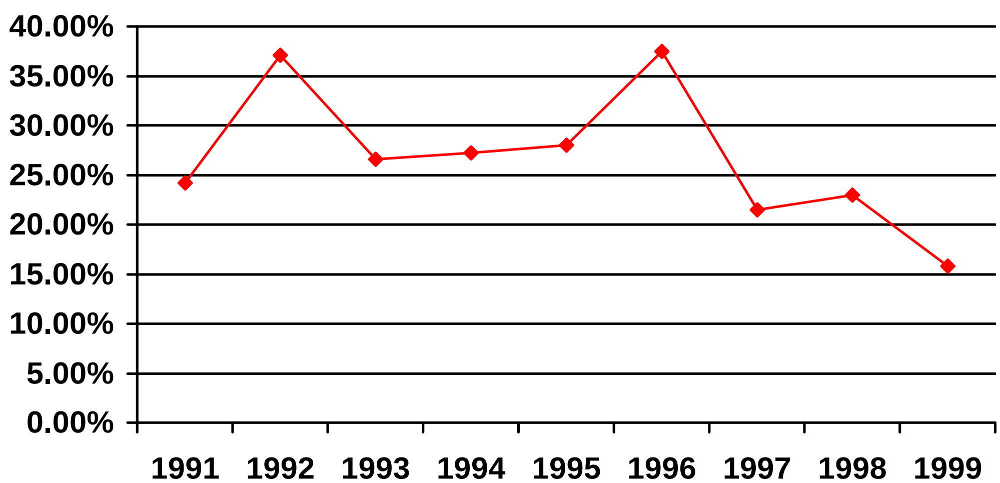
Contracts Utilities Signed with Other Utilities

In a few cases, utilities signed high-rate contracts for power supply with other utilities. Many municipalities and smaller utilities had "all-requirements" contracts to buy power from neighboring utilities. Vermont utilities, for example, signed a contract in the late 1980s with Hydro-Québec, a Canadian utility, to buy hydro-power over a 30-year period. Like the contracts with non-utility generators, the contract with Hydro-Québec was set to reflect electricity prices that were expected to rise, and cost less than new generation options that were available at the time. When wholesale prices in the rest of the country and New England began to fall in the late 1990s, Vermont's long-term contract with Hydro-Québec seemed over-priced.

B. RECENT HISTORY

By the early to mid-1990s, retail electricity rates had absorbed and reflected many of the high costs described in the previous section. But by then, the wholesale electricity world had begun to change. With the success of many energy efficiency programs, the influence of PURPA and a slower economy, it became clear that there was, in fact, more generation on-line in much of the country than appeared necessary. Reserve margins in some parts of the country reached 20 percent to 25 percent and more. (Many analysts suggest generally that margins of approximately 12 to15 percent are sufficient to maintain a reliable system.) This oversupply put downward pressure on wholesale electricity prices. The following chart illustrates this trend as it occurred in New York. It shows the variation in reserve margins, indicating the fluctuation in power reserves over time.

Figure 4. New York State Reserve Margins in the 1990's



Source: New York State Energy Research and Development Authority

At the same time, natural gas prices were at historically low levels, reflecting innovations in gas drilling and exploration techniques, as well as increased access to Canadian supplies through new pipelines. The shift to gas generation was also a product of the low capital cost of gas plants and newly efficient gas turbines.[13] Such turbines, developed in the aerospace industry, had moved plant efficiency rates from the mid-20 percent range to the mid-50 percent range and above. Since most of the new power generation facilities used natural gas, any new facility coming on line was likely to be able to produce power at rates far below the wholesale costs embedded in the existing retail rates. The following chart illustrates the trend in natural gas prices, showing the relatively stable and low prices over an extended time, followed by a period of much greater volatility in the very late 1990s to early 2000s.

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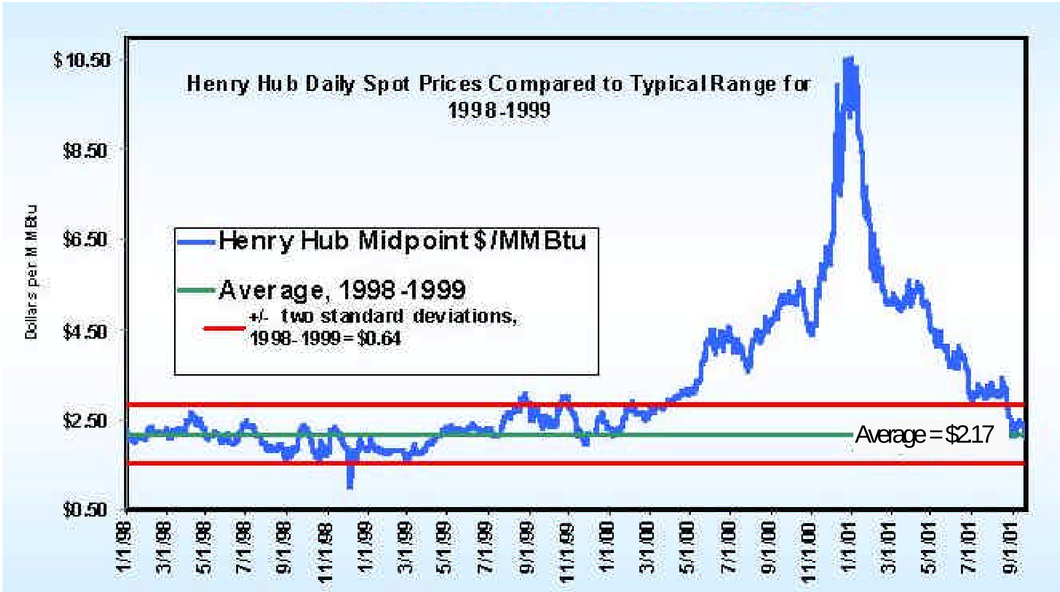
[13] Gas turbines had been relegated to stand alone use during peak hours. Increased combustion efficiency and durability allowed them to operate all the time. Use of their considerable waste heat by a steam boiler around the clock led to additional efficiency improvements, and leads to the term "combined cycle."

Figure 5. Natural Gas Prices, January 1998—September 2001[1]



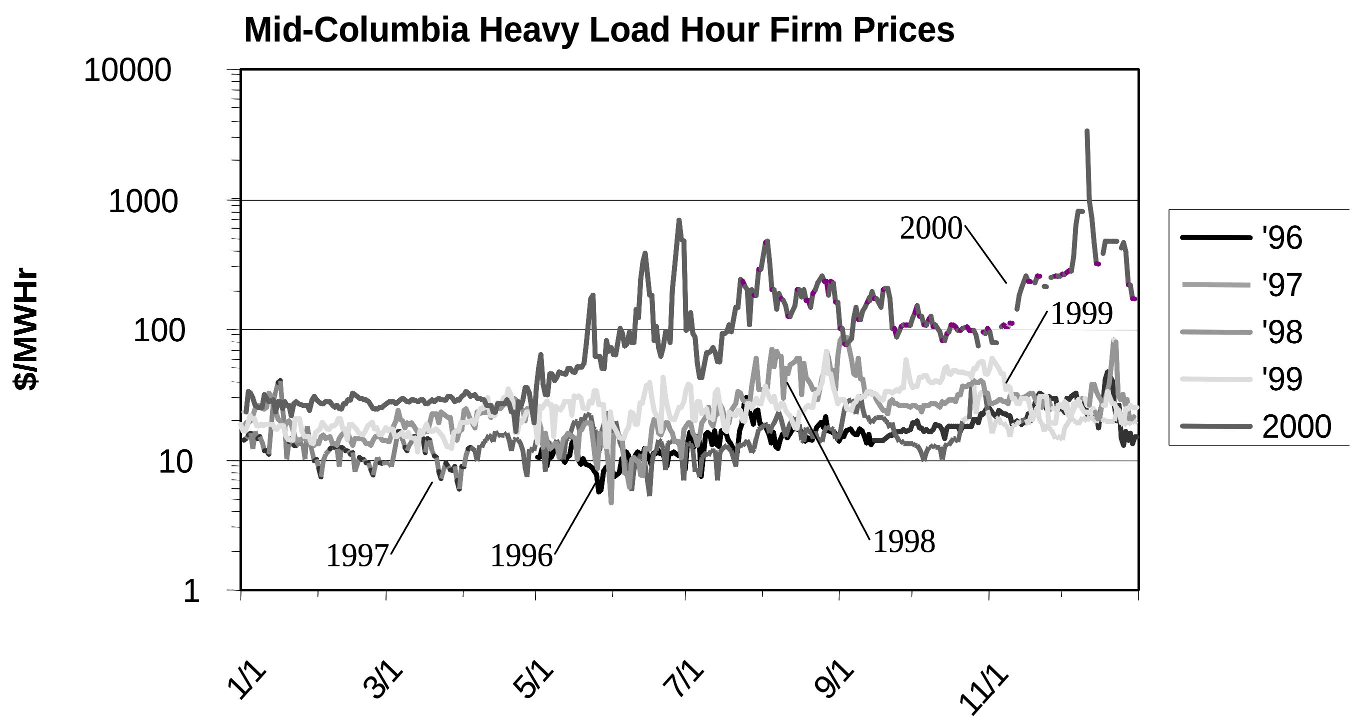
[1] Notice that the natural gas spot prices are back within the 1998-1999 range by September 2001.

Source: Financial Times Energy, Gas Daily

In some parts of the country, particularly in California, wholesale electricity prices fell still further because of several years of abundant precipitation in the Pacific Northwest, which translated into the ability to export surplus hydro generation to California. Power from the Pacific Northwest through the mid-1990s was available for less than 1 cent per kilowatt-hour, as figure 6 indicates.

Some large consumers saw low regional wholesale electricity prices and high local retail prices, and began to seek out ways to bypass the high retail rates and gain access to low-cost wholesale power. Some of these had already won lower rates in the monopoly system through economic development or load retention rates, as discussed earlier. These customers wanted to use the distribution system to deliver this low cost power, or “wheel” the power they would acquire themselves. This is the origin of the term “retail wheeling”. Restructuring of the electric industry, therefore, seemed to them to be a viable option to get out from under the evidently inefficient system of monopoly regulation that they blamed for creating high rates in the first place. These customers did not want to pay for power from a local utility’s inefficient, obsolete technologies or for legacy contracts signed with much higher projections of long-term electricity costs in mind.

Figure 6. Mid-Columbia Heavy Load Hour Firm Prices



Source: Northwest Power Planning Council

Reasons for the Transition to Competition

Competition advocates and policymakers saw the problems and the situation described above and formed a series of intellectual arguments to support competition. These arguments are:

- Competition could encourage companies to focus on core competencies.
- Competition allows marketers to meet customers' needs by selling differentiated products.
- Regulation misdirected investment signals.
- Competition would force a reassessment of the risk-reward allocation.
- Competition could remove utility costs from rates.
- Markets work better than government regulation.

Competition could encourage companies to focus on core competencies

With electric restructuring overwhelming the culture of the industry, utility executives turned their attention to "core competencies." Like companies in other industries, many electric company managers decided that some elements of their integrated operation were good to excellent, while others were not.

For example, National Grid and Energy East, two power companies that operate primarily on the east coast of the United States, shed their generation, concentrating on expanding transmission and distribution service areas. Xcel Energy, in the Midwest and mountain west, and Southern Company created generation-owning affiliates and spun them off to shareholders.[14] Pennsylvania Power & Light and Pacific Gas and Electric became national generation owners that continued to maintain their local wires businesses. Montana Power, in an extreme case, used its control of long rights-of-way to exit the electricity business to concentrate on telecommunications. California's Sempra Energy expanded its presence nation-wide as an energy services company, while, TXU from Texas and several others sought to export their skills to other countries.

Some companies specialized in specific generation types: Entergy in nuclear power; FPL in wind power. Cinergy developed special skills in energy trading. Other services becoming the focus of specialization include unregulated transmission lines (TransÉnergie, a unit of Hydro-Québec); emergency response for distribution repairs (Quanta Services) and even call centers and billing.

Prominent Generating Companies in the United States

The following are the names of some prominent owners of generation. Many names only vaguely hint at the utility affiliate from which it was created, while others are entirely new.

ABB Equity Ventures	Dynegy	Orion
AES	Edison Mission Energy	Panda
Allegheny Energy Supply	El Paso Energy	PG&E National
Aquila	Enron	PPL Global
Black Hills	Entergy	PSEG Power
Calpine	Exelon	Reliant
Cinergy	FPL	Sithe
CMS	Indeck	TECO Power
Cogentrix	Intergen	Tenaska
Constellation	International Power	Tractabel
Dominion	Mirant	Trans Alta
Duke	NRG Energy	

Competition allows marketers to meet customers' needs by selling differentiated products

All residential, commercial or industrial customers have had the opportunity to buy a product that reflected their utility's average costs and average generation mix. Until recently, customers had little choice but to buy the single product that they were offered.

Competition gives sellers a chance to target specific customer groups – allowing customers to buy electricity products with specific price or environmental characteristics. In fact, as the industry restructured, power companies found some customers were indeed interested in different products. Three types of products that have gained some acceptance: green energy products, time-sensitive priced products and "bundled" products.

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[14] In some cases, the utility retained significant ownership in the generation company, retaining significant residual risk.

Oregon and western New York Niagara Mohawk customers can now buy products with a price that changes over the course of the day or buy "green" products. Green products generally guarantee that power is generated from wind, geothermal, biomass or other renewable source. Most of the customers in California, and many elsewhere in the country, who bought a competitor's product chose one billed as a "green" product. Pennsylvania officials attribute the development of wind generation in that state to the consumer market demand for power from such sources. Some corporations and government agencies made choosing a clean energy product a policy priority.

Larger customers were able to buy products priced to more closely reflect the wholesale market – a move that saved them money as long as wholesale prices were low, or at least predictable. When wholesale prices climbed quickly, as they did in 2001, these products seemed less attractive. Simplified versions of market based products have been made available to smaller customers for several years, as described in the text box.

Finally, some marketers have offered a bundled set of services. Western Resources in Kansas bought a home security company in order to offer power bundled with home security. Enron, before it entered bankruptcy, offered large customers a full energy management package, including power supply procurement and energy efficiency and management. Although it has not happened to any large degree, some observers have asserted that an energy services company could manage a customer's energy supply and install energy efficient equipment, using the cost savings to pay off the capital cost of the new equipment and make a profit.

Regulation mis-directed investment signals

The utility industry entering the 1980s had total responsibility for all investment needs for generation, transmission, distribution, customer care, etc. In some cases, utilities absorbed criticism for their investment decisions, and for the processes employed to reach those decisions.[15]

[15] Nuclear power construction disallowances were only the most spectacular of these. These reflected a view that prudent management would have stopped construction, or at least reconsidered continuing as evidence of spiraling costs became evident.

Time Sensitive Retail Pricing Supports Wholesale Markets

Some alternative electricity products vary by the time of day. Time-of-Use pricing has been around for decades, and requires only a modest metering enhancement – ability to record usage during discrete, pre-selected time intervals. Advances in metering and telecommunications have made real time pricing, critical peak pricing and price responsive demand programs feasible.

Real Time Pricing, as the name suggests, charges the consumer a market price for consumption in a given time interval. Two-way communication is needed to put together the usage and pricing information. It is also important that the customer be able to see the real time price so that the customer can curtail or increase use based on the price.

Critical Peak Pricing is a simplified version of real time pricing. As implemented by Southern Company in two pilot programs, there are four pricing periods. These can be roughly described as off-peak, average, on-peak and critical peak. The price during the critical peak is very high, reflecting very high system costs at these times, but the number of hours that the critical peak price can be charged is capped at 1 percent per year (about 88 hours). Customers are notified with some minutes of warning when a critical peak period is about to begin, enabling customers to curtail use at their option for the next couple of hours.

Demand Response allows the system operator to curtail or reduce a customer's electricity use, and compensates the customer based on the value of the interruption to the system. The customer's load, then, becomes a peaking resource for the grid, because the electricity the customer would have used can be distributed to others. Some systems are experimenting with allowing the customer to bid planned by curtailable consumption into the daily dispatch, allowing a more dynamic economic relationship between the customer and the market.

All of these approaches serve to use existing facilities more efficiently, and to delay the need for new investment.

Some observers suggested that utilities did not face enough financial risk. They suggested that customers would have to pay for almost all utility investments and expenses, whether they turned out to be good or bad decisions. This implicit criticism of utility regulation reveals an important assertion leading to the restructuring movement: over the long run, utility regulators do not hold utilities sufficiently accountable for their capital decisions, and consumers actually bear the risk of utility and regulator mistakes.

Regulators did find utility imprudence in some cases though remedies for consumers varied by state.[16] In a few cases, imprudence findings and resulting cost disallowances did lead to bankruptcy and significant shareholder losses. In other cases, critics charged that this result was too uncommon and that it was more typical to let the utility off the hook, charge the consumer with the lion's share of the losses, avoiding a pitched legal and political battle.

[16] These reflected the view that prudent management would have stopped construction, or at least reconsidered continuing as evidence of spiraling costs became evident.

Restructuring Uncertainty Affects Grid Investment

As discussion of electric industry restructuring became more serious in the mid 1990s, a negative by-product became evident. Uncertainty about what the new regulatory and market rules would be was so significant that electric utility investment slowed to an alarming degree.

Generation and transmission projects were few. Energy efficiency investment levels dropped precipitously. Utilities worried that costs of long-term investments may not be as likely to be recovered in rates as they were before. Planning became more short-term focused. Utility staff became aware of the prospect of mergers leading to workforce cuts.

As restructuring issues were debated in state capitals, it became evident to some policymakers that, in some instances, an answer, any answer, that would bring certainty to the industry was very important to the near term success of the electric industry in its mission to serve customers.

Competition would force a reassessment of the risk-reward allocation

The electric industry CEO has walked a fine line in the last decade. On the one hand, the low risk quality of utility stock pleased many shareholders. On the other hand, pressure to drive up stock price through earnings growth led many companies to seek higher earnings through new lines of business.[17] Electric industry restructuring created new diversification opportunities and induced fundamental changes in the risk/reward relationship for shareholders and consumers.

In 1999, 43 percent of IOU electric revenues came from non-regulated businesses, a 28 percent jump from 1998. The primary area of growth was energy trading and marketing. Other significant growth areas were international activities, telecommunications and energy services.[18]

Most visibly changed was the U.S. electric generation fleet. Since about 1995, new power generation has been built primarily by generation companies, and many older generating stations have been sold by utilities to these new competitive giants. In July 2002, more than one-third of the energy generated during the month came from non-utility generators.[19] These generation companies have devised new strategies to manage their power plants.[20] Connectiv, for example, assembled a fleet of generators that operate between base and peak load times, ramping up and down on a daily basis.

If retail electric competition works as well in practice as it does in theory, it should insulate consumers from the risks of relying completely on one monopoly provider. If the consumer is in a retail competition state, and the supplier raises prices because of a risk gone bad, the consumer

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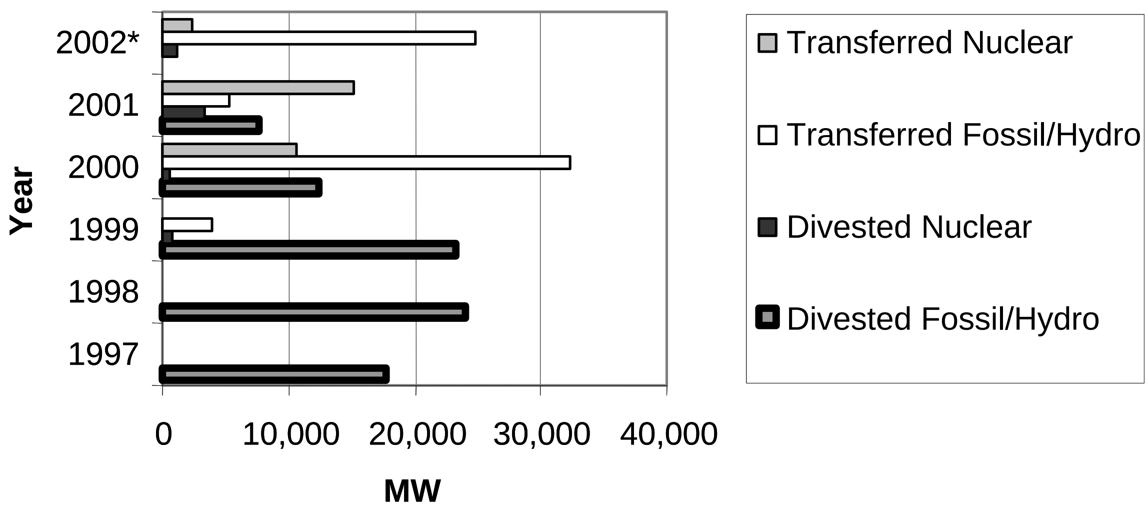
[17] This motivation was probably made more extreme by the over-heated stock market. Pressure to compete for shareholders' attention and investment dollars was high.
[18] Esquivar, Joan and Mark Agnew, *"Revenues Climb in Non-Regulated Business"* Electric Perspectives Nov/Dec. 2000.
[19] U.S. EIA. Electric Power Monthly Table 2 December 2002. http://www.eia.doe.gov/cnaef/electricity/epm/epmt02p1.html
[20] Absent regulation, utilities may be tempted to manipulate their resources to drive up prices. Regulation serves to limit the use of market power by removing the opportunity to profit from this behavior.

Figure 7: Ownership Transfers and Divestitures of Electric Utility Assets



Source: Edison Electric Institute, 2002

can switch to other suppliers.[21] Or, if a utility affiliate's investment fails, it should not affect the utility regulated services, since regulators require the regulated and the competitive portions of the business to be separate from one another. As an example, regulated utility customers should not be affected by the severe financial problems of its generation affiliate.

On the other hand, deregulation without competition – meaning restructured markets that do not give customers a choice among different providers – can force customers to rely on one provider that does not have the benefit of the traditional utility's diversified generation portfolio. California customers in 2000, for example, found themselves relying essentially on the spot market.[22] Customers found themselves with new and unexpected risks, such as sudden retail price spikes. Meanwhile, depressed earnings of affiliates, such as the NRG generating unit of XCEL Energy, can create unexpected risk for the regulated utility. State policymakers need to devote careful thought to policies that assure consumers do not end up with unexpected or unacceptable risks while trying to manage and remove old risks.

[21] Significant flaws in the idea of customer choice were not understood as states began restructuring. One flaw relates to the default service provider, and the risk associated with this new supplier. Might the default provider go out of business, or get itself into a bad generation portfolio? Protections are needed to assure consumers are served. Third parties, including energy trading affiliates to utilities, who become integral in the supply chain may present another source of unexpected financial risk, potentially affecting many suppliers in a region.

[22] The authors of this paper have chosen not to dwell on the failures of the California electric restructuring effort. These problems have been well-documented elsewhere, including Brown, Matthew H., *California's Energy Crisis: What Happened? What Can Be Learned?* National Conference of State Legislatures, March 2001.

A Regulatory Compact?

Two prominent voices in the stranded cost debate were the Edison Electric Institute (EEI) and Peter Bradford.[1] EEI represents the interests of the investor-owned electric utility industry.[2] Here are excerpts of what they had to say. Note that utilities tend to favor the term “transition costs.” Also note the tactical aspect to the stranded cost issue in both pieces.

EEI

Fairness and Honoring Commitments: When utilities built power plants, power lines and entered into contracts to supply power to their communities, they assumed a large "mortgage," which utilities would pay off over time under the agreements made with regulators. In the eyes of all, these agreements were in the best interests of all. Competition changes the rules to give consumers choice, but the "mortgage" (now called transition costs) still has to be paid off.
Jobs and Tax Losses to Communities: If consumers buy power from some other supplier, the power plant and other facilities built by the local utility may no longer be needed. However, the utility company still must pay for that plant and equipment. If no provision is made for recovering those costs from customers who switch to other providers, serious economic injury to the utility -- including bankruptcy -- can occur. Electric utilities are among the larger tax-paying businesses in the communities they serve. To the extent that their economic health is damaged, their economic contributions to their communities are endangered. Their contributions include thousands of jobs, and millions of dollars in property, corporate sales and other taxes and franchise fees.
Legal Delays in Moving to Competition: In the states that are implementing retail competition, it has been found that providing fair and equitable recovery of transition costs is helping to move the change to competition forward. If recovery is not provided, lengthy legal delays can result. That is because utilities have a "fiduciary responsibility"-- a binding legal obligation -- to protect shareholder's investments from illegal "takings" or other actions. Fulfilling these obligations may require civil litigation.

Competition could remove utility costs from rates: the stranded cost debate

In the midst of the controversies over social and economic principles in the restructuring debate, both consumer advocates and utilities recognized an opportunity to score huge victories in the perpetual cost-of-service war usually fought in rate cases. This opportunity arose with the debate over “stranded costs.”

Stranded costs represent the difference between existing utility sunk or committed costs, and the costs that would be recoverable in a fully competitive market. For a utility with an expensive nuclear power facility or a high cost PURPA contract, there was fear that revenue under the new competitive system would not cover cost. Most, though not all, utilities entered the restructuring

Peter Bradford

The [regulator] is free to handle the strandable investment issue in whatever manner will best serve the public. I want particularly to dispel the claim that some societal "compact" compels the [regulator] to assure the recovery of every dollar not found to have been spent imprudently. My conclusion is based on several propositions:

1) There never was a regulatory compact.
2) Investors have long been well aware that serious losses, even bankruptcy, were possible in the electric utility industry and that no compact protected them from technological or regulatory change.
3) Electric utility investors have for many years been compensated at levels sufficient to cover the risk of some loss of their strandable investment.
4) Not all strandable commitments were prudently incurred.

A decision to allow stranded investment recovery is a social policy decision, as surely as is a renewable portfolio requirement or a lifeline program or an economic development rate. Indeed, the decision to allow a lost revenue adjustment and performance incentives in the context of utility DSM programs were a similar linkage of shareholder well-being to the achievement of larger societal ends.

The bottom line is clear enough. Strandable investment is the public's best leverage to an effectively competitive future. Don't give it away until that future is well secured.

[1] Bradford, Peter, Testimony before the Vermont Public Service Board, Docket 5854, 1996, http://www.state.vt.us/psd/vttesty2.htmm. Bradford is a former state regulatory commission chair in Maine and New York, and a former commissioner at the Nuclear Regulatory Commission.
[2] Straight Talk about Stranded Costs. Edison Electric Institute. 1999. http://www.eei.org/issues/comp_reg/talkcost.htm

debate with some generation investments that would be uneconomic in a competitive market,[23] as well as other costs deferred for future collection with regulators' permission.[24]

For consumer advocates, large consumers, and power marketers, the opportunity to label stranded costs as failed investments by utilities, and then exclude some or all of them from on-going regulated rates would be a victory far in excess from what could be achieved in a rate case. One reason this opportunity seemed feasible is that the rules for cost recovery seemed suddenly (and

[23] These sources were reviewed earlier. Since PURPA contracts were supported by government policy, utilities had a special claim for full recovery of these costs, though utilities retain an obligation to reduce these costs if they can. The lowering of long-term marginal costs brought about by new natural gas-fired combined cycle facilities meant that even utilities without construction debacles or other resource acquisition missteps found themselves with potential stranded costs. Only utilities with older coal and hydro resources (much depreciated, low interest rate, low fuel cost generation) seemed immune.

[24] Allegheny Energy opposed stranded cost recovery, arguing that it could delay the development of competitive retail electric markets. Conveniently, Allegheny had no significant stranded generation costs – Alan Noia, remarks to "A Mid-course review of Electric Restructuring in the Mid-Atlantic States," May 2002.

temporarily) to be in play in the midst of a transition from regulated cost-based rates to market-based rates.

The implications of such a radical change were large, and included possibly removing so much revenue from rates that utilities could weaken, be unable to raise capital and be forced to cut essential elements of electric service, harming consumers and inviting hard times with regulators.

Utilities looked at the same situation and saw a different opportunity. They saw promise in the idea of identifying stranded costs and removing them from base rates. Their mission, however, was to convince state policymakers that this bundle of "stranded costs" should be fully recovered from all consumers in a separate charge.[25] Further, it would be less expensive for consumers if this bundle of costs could be turned into a very secure financial instrument with lower costs of money than that typically available to the utility, guaranteed by the regulators' commitment to fund payments on the instrument. The process of creating these instruments, called securitization, has been widely used in other areas of finance, but was totally new to electric regulation.[26]

This debate hinged on the accuracy of forecasting. Both the future utility costs, and the expected cost of competitive sources over time, are forecasts. Recognizing that these figures are uncertain, and that the variability is far outside state control, great caution is needed (though not always applied) in using these figures to commit ratepayers and utilities to a long-term fixed financial instrument like a securitization trust.

An example of this multi-sided debate occurred in Pennsylvania with PECO Energy. In that case, Enron made a very public effort to minimize the amount of stranded costs the utility could recover. The PUC eventually allowed in rates an amount significantly less than that asserted by PECO to be appropriate.

In this case, the uncertainties in the forecast allowed some to assert that the reduced amount allowed to PECO Energy was actually more than sufficient to cover actual costs likely to occur. In many states, however, with billions of dollars at stake, this transitional issue became a pitched and frenzied battle that overwhelmed the discussion of forming new working electricity markets for the long-term benefit of consumers.[27]

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[25] Customers might consider self-generation and isolation from the power grid to avoid this separate charge for uneconomic commitments. In response, policymakers considered an exit fee to assure that all present customers pay the charge unless they physically leave the system. Some communities considered creating municipal utilities to avoid stranded costs of the utility serving the area. Most moves toward the development of municipal utilities were abandoned when efforts to value distribution system included the costs for these uneconomic assets, removing much of the value for the municipalization effort.

[26] Securitization could increase the chances that utilities would recover 100 percent of costs and created the very real possibility that utilities would recover revenue against forecasted costs that would never occur. This last point is a vital point of arguments opposing securitization.

[27] Utilities also expressed concern about a new category of stranded cost in the distribution system. They observed that if customer-owned generation becomes typical, and customers leave the grid, the revenue stream supporting local poles and wires could be handicapped. While this situation is not on the horizon, it is not too early to consider ways to assure (for the benefit of customers without these modern options) that the basic utility business model will continue to provide service at reasonable rates regardless of where restructuring takes the industry.

Markets work better than government regulation

Some advocates for electric restructuring were unsatisfied with the degree to which other colleagues wanted to maintain or just retarget regulation. The Cato Institute, a think tank, represents this perspective. In this view, the functions which could be fairly defined as "natural monopoly" and entitled to some regulation are few. The diminishing of scale economies in the electric industry due to innovations in distributed generation was one reason the Cato Institute cited for the erosion of the natural monopoly – small scale generation was already or soon would be a viable price competitor to large central generation. With this level of choice, customers would have a real "build or buy" decision concerning their energy supply, and distribution companies would have to lower costs and improve service to retain customers interested in buying power services in the traditional way.[28]

While some viewed markets as the paramount objective from which certain benefits will flow, others viewed markets as one of many tools to deliver value to customers. Their support for restructuring was reliable only as long as customers were likely to benefit.

[28] Taylor, Jerry, *Deregulation or Managed Competition?* Cato Institute, January 1997. The optimistic view of customer-owned generation appears somewhat ahead of its time. Utilities are concerned, however, about the prospect of losing their monopoly on distribution service.

ELCON's Principles for Electric Competition

The Electricity Consumers Resources Council, a trade association of large electricity users, seized on retail competition as a centerpiece issue, and became one of the most focused advocates for national change. Extracted here from the policy position of ELCON at the end of 1994, are its eight principles.[1]

1. Market forces can do a better job than any government or regulatory agency in determining prices for a commodity such as electricity.
2. Laws and regulation that restrict the development of competitive electricity markets should be rescinded or amended. The need for burdensome regulation will be reduced where competitive electricity markets are allowed to flourish.
3. The benefits from competition will never fully materialize unless and until there is competition in both wholesale and retail markets. But not all retail electric services are natural monopolies and therefore, they should not be regulated as such.
4. The owners and operators of transmission and distribution facilities, and the providers of coordination and system control services, should be required to provide access to those facilities and services to any buyer or seller on a non-discriminatory, common-carrier basis.
5. Rates for the use of transmission and distribution facilities should reflect the actual cost of providing the service. If a facility is a natural monopoly, those rates should be based on actual costs and the services provided on a non-discriminatory and comparable basis for all users.
6. Resource planning is not a natural monopoly. The types and market shares of generation and end-user technologies that will be supplied in wholesale and retail markets should be decided in the marketplace.
7. Legitimate and verifiable transition costs that develop as a result of competition should be recovered by an equitable split among ratepayers, shareholders and taxpayers. The costs of assets that were uneconomical in the existing regulatory regime are not transitional costs.
8. The potential for transition costs should not be used as an excuse to prevent or delay the onset of a competitive electricity market.

[1] ELCON Report, Winter 1994.

C. MAJOR CONCERNS OF POLICYMAKERS

At the outset of restructuring debates in capitals across the U.S. policymakers raised several common concerns:

1. Stranded Costs. Should the utilities receive an assurance of recovery of stranded costs, placing the burden of these costs squarely on consumers, or should there be a sharing of stranded costs between the utility and consumers? Also, how long should a stranded cost obligation last?

2. Market Power. What actions should policymakers take to prevent the incumbent utility or other power market players from controlling the market for power once competition is allowed? Generally, this concern is about the ability of one or a small number of parties to manipulate market prices.[29]

3. Public Benefits. Should some or all of the social benefits of retail electric service, often taken for granted, be identified and delivered in new ways, if the ability of the incumbent utility to accept public service obligations is diminished?

4. How can consumers be assured that restructuring will be positive? (and should "positive" be measured on a societal basis or on a "no losers" basis?)

5. How will consumers be educated about their opportunities in a new retail market for electricity?

6. How will restructuring affect government revenues?

7. Will restructuring have a positive or a negative affect on the environment?

8. Aside from market power protections, what other market rules are necessary to protect consumers (given that market players will push the rules in search of profits)?

9. Will utility workers be unfairly disrupted by restructuring?

10. In what ways may a state lose control over the electric industry if it allows retail competition, and are there ways a state can or should mitigate this loss of control?

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[29] Market Power is a very complex subject. It arises when particular suppliers have some means of significantly influencing market prices, leading to prices that are significantly higher than would result if the market were truly competitive. Two categories of market power are horizontal and vertical. Horizontal market power arises when there is excessive concentration of ownership or control of one element of a competitive market, for example, generation. Vertical market power arises when there is concentration of ownership or control of all the elements of a competitive market that serve certain customers. A vertically integrated monopoly, one that owns and controls the wires and the generators, is unlikely to allow a competitive market to flourish. Changing ownership, control, or market rules is the key to addressing market power in advance in the absence of regulation. One other point is important: identifying market power is not easy. Strategies to exert market power are sophisticated. The opportunities to exercise it may be infrequent, but the potential to inflate costs in these times is significant. System operators and FERC are gearing up to study market behavior that suggests market power may be at work. While market power was identified early as a concern, competitive wholesale markets were launched without sufficient protections against market power in place. Efforts to remedy this deficiency are presented as a dominant concern of regulators.

In the next section this report will begin to explore what policymakers and regulators actually did in response to these many pressures. There, we will review actions that drove states toward restructuring. Many states, looking at the prospect for change, decided to do nothing, out of mistrust of new market actors, out of confidence that, despite its flaws, regulation was working well enough, or out of fear of change without more evidence that new markets would work as promised. In states with low cost power, policymakers determined that breaking up the vertically integrated utilities could cost their constituents as a result of losing exclusive rights to that power. It remains to be seen whether wholesale competition will make this result inevitable.

III. MODELS FOR STATE RESTRUCTURING AND EARLY RESULTS

By in the end of 2000, 24 states had enacted legislation to open their retail power markets to competition. These laws were complex and the result of lengthy negotiations and compromise. With only two exceptions – Oregon and Nevada – the new state laws aimed to give all retail customers access to competitive power markets. Oregon and Nevada restricted competition to the larger customers.

These laws set up transition periods during which the utilities would be able to recover stranded costs (costs that they had incurred, with regulatory approval, before the start of competition that they would not be able to recover after the transition to retail competition). These transitions also gave customers an immediate benefit by requiring lower rates, or were meant to shield them from any chance that their rates might go up, by freezing or capping rates for a period of years. The laws also tried to address the ability of any one company to control markets, and tried in some cases to stimulate competition. Many laws also built in new ways to fund programs that utilities had historically provided, including energy efficiency, renewable energy, research and development or low-income customer programs.

This section begins with a brief review of the results of some of these state efforts to stimulate competition, and continues with a discussion of the many approaches that states took to restructure their power markets.

The results of these new laws have shown that for the most part competition, in the form of distinct choices of electric supplies has been slow to come to the smallest of consumers, while the larger consumers have received more attention from marketers and generally been able to take advantage of the competitive market. A few examples, below, illustrate this situation in California, Montana, Massachusetts and Ohio.

California Switching Data: October, 2000

	Residential	**Commercial**	**Industrial**	**Agricultural**	**Total**
Customers Switching	1.7%	7.5%	12.8%	2.5%	1.8%
Load Switching	2.0%	16.1%	27.4%	6.9%	11.9%

Montana Switching Data

	July, 1998	**Sept. 1998**	**July 2000**	**July 2002**	**Sept. 2002**
# of Residential Customers Switching		--	943	80	77
Small Commercial		20	1179	1340	1274
Industrial	1	24	33	35	38

Source: Northwestern Energy

The California market showed few residential customers switching to new providers. Of note, though, is that the vast majority of the customers in California who switched did so in order to buy a "green" environmentally distinctive product. Montana's market, by contrast, was even less active for the smallest consumers, while many of the largest consumers did purchase power from competitive suppliers – representing a significant proportion of the utility's – Northwestern Energy's – load.

Massachusetts reflects a similar situation, but perhaps even more dramatic, with fully 38 percent of the industrial load having switched while less than one percent of the residential customers switched to a new provider. As with California and Montana, the largest customers who represent a relatively small number of the electric meters but a large percent of the kilowatt-hours were switching.

Massachusetts Switching Data: March, 2002

	Residential	**Small/Medium Commercial/ Industrial**	**Large Commercial/ Industrial**
Customers Switching	0.4%	4.2%	24.8%
Load Switching (Industrial Only)	-	-	38%

In Ohio, it is similarly the case that only a few residential and small business customers sampled a competitive product. The only situation in which large numbers of small customers switched providers is in the Cleveland, Ohio area (and much of northern Ohio) where a new organization of cities and towns known as the Northeast Ohio Public Energy Council aggregated a group of more than 300,000 customers through an "opt-out aggregation" program.[30] These customers who lived in close to 100 cities and towns were given the option to buy power on their own or to let their municipal government buy power on their behalf. The opt-out aggregation process assumed that the customers would be a part of this large, aggregated group unless they affirmatively stated that they did not want to be a part of the group. This process is one of the only ways that large blocks of customers have thus far switched to a competitive provider. Otherwise, few competitors are marketing to the small customers and few of them are switching to new providers.

Ohio Customer Switching Data: 2002

	Residential Customers	**Small Commercial /Industrial**	**Large Commercial/ Industrial**
Cleveland	55%	22%	18.8%
Toledo	5%	20%	4%

[30] http://www.nopecinfo.org/

A. SLOW DEVELOPMENT OF SMALL CUSTOMER MARKETS

There are several reasons that most retail power markets have been slow to develop for the smaller customer. Five of these are particularly prominent.

Marketing Costs

Interviews with retail electricity providers over the course of the previous several years reveal that the costs of acquiring a new retail electric customer are in the range of $200 per customer. Sometimes they are less; sometimes more. One somewhat analogous example comes from the telecommunications industry. Excluding all other costs for mailing, personnel and so on, it has been common practice for telecommunications providers to send checks of up to $200 to potential customers; cashing such a check signifies agreement to switch to a new provider.

Small Savings for Small Customers

Small customers, by definition, use little electricity. The Energy Information Administration of the U.S. Department of Energy cites 700 kWh per month as a typical customer usage. Savings to customers in competitive power markets, when customers have switched, have ranged from 2 percent to 10 percent.

A Typical Residential Customer's Monthly Bill	**$ 70.00**
40 % of Typical Bills is For Power Delivery	**(28.00)**
Portion of Bill Subject to Competition	**$ 42.00**

Typical savings for a residential customer have tended to be from 2% to 10%. Monthly savings range from 84 cents to $4.20.

Volatile, Evolving Wholesale Markets

Wholesale power markets have been volatile in most parts of the country between 2000 and 2002. In part because of rising gas prices, in part because the markets and the rules governing those markets were still evolving, and in part because of a long-term lack of investment in the power sector, these markets have gone from historically low prices to historically high prices and down again in a surprisingly short period of time. The volatility in wholesale markets has made it difficult for electricity retailers to make long-term commitments in the retail markets, since they often have not known how much their own power supplies would cost.

Small Margins on Serving Retail Load

The electricity business is not generally one in which electricity retailers make large profits on each kilowatt hour they sell. Profit margins are different for different classes of customer, but tend to be a penny or less per kilowatt hour.

Retail Market Rules and Last Resort Service

Detailed – or not so detailed – rules that many states set up to govern retail markets ended up having a huge effect on how quickly competition developed in retail markets. Implicitly, the rules also often reflected the degree of certainty on the part of policymakers that competition would offer sufficient protection to customers, or that competitors would emerge quickly seeking consumer accounts.

These rules have turned out to be even more important in the electric business because retail margins are so small. Small disruptions and small difficulties can make or break an already fragile market.

Some of the more important rules have to do with regulated prices; every state set up a regulated price that customers who had not chosen an alternative provider would pay.[31] In effect, this regulated price became the price that marketers had to beat in order to win a new customer. Low regulated prices are harder to beat than high regulated prices. Fixed and stable regulated prices are harder to beat in a volatile wholesale power market, than regulated prices that rise and fall along with the wholesale power market. The paradox in which most state policymakers found themselves is that most customers are happiest with low and stable retail prices, and indeed such prices are beneficial (at least in the short-term to most small consumers). Yet, the low regulated prices that most policymakers set for the customers who did not choose have made it more difficult for retail marketers to find customers than high retail prices, limiting actual competition.

While traditional regulation has standard practices to guide rate-setting, the process of setting initial regulated rates in the competitive era was more creative. Some departed from regulatory principles entirely, making a political bargain with utilities that challenged them to keep rates at an ultimately arbitrary level for some time. Sometimes the utilities or regulators required a rate reduction. California departed from the standard rate-setting structures. Other states retained a more cost-based rate structure.

Even among the states that retained the cost-based rate structure, however, there was a range that was caused by differences in what costs regulators assumed to be part of the regulated service, and what costs they thought to be part of competitive service. Some states, like Massachusetts, defined power costs as competitive and included nearly all other costs in the regulated distribution rate. As a result, the Massachusetts “standard offer” rate appeared quite low. Other states included more costs such as customer care and marketing in the competitive rate.

Massachusetts opened its markets to competitors and simultaneously gave customers a discounted rate, whether or not they chose an alternative provider. For the six months immediately following March 1, 1998, customers who did not choose an alternative provider paid only 2.8 cents per kWh for the energy portion of their power bills. (As in every other state, transmission and distribution rates remained regulated). At the time, however, spot market energy prices in the New England region were around 3.2 cents per kWh. Marketers who wanted to attract customers would have had to beat the standard offer of 2.8 cents if they expected to win customers on the basis of price alone. Yet beating that price was difficult under conditions in which they could not

[31] This service is called by different names among the states: default, last resort, provider of last resort, and standard offer. The matter is further complicated by the fact that some states have one service for customers of record before the transition to competition, and another service for new customers.

procure power for less then 3.2 cents per kWh. Since the market opened in 1998, the standard offer price has gradually increased, as have wholesale market prices. Yet the relationship between wholesale prices and the standard offer price has not yet been such that competitors have been able to enter the market and make a profit.

Other retail market rules have turned out to be very important as well. A requirement that customers actually sign a piece of paper saying that they want to switch providers (a "wet signature requirement"), rather than allowing an independent company to verify a switch made via the telephone or the Internet adds significant cost and hassle to the act of switching. Restrictions on what information about customers the utility can give to marketers also cause problems for marketers seeking to target particular customer groups. Many states have addressed these issues in some way; however they remain significant in other states.

With small retail margins, it has become clear that marketers need to have most everything else go exactly right when they are in the small retail customer business. Small barriers make a big difference. *If* the goal is to create a market that encourages retail marketers several circumstances must be in place:

- Wholesale markets must be predictable enough that retailers can absorb, or manage, their risk exposure.
- The pricing of the non-competitive default service (service for the customers who do not switch providers) must be predictable and – even high enough to allow the marketers to still make a profit.
- Retail market rules must be amenable to the retailers – including such items as billing, information disclosure, sharing of information, customer switching procedures etc.

Small glitches such as incompatible computer systems become expensive and can make the marketers' job difficult. Yet small glitches, and sometimes, larger problems, are common if not inevitable in a transition as far reaching as that being attempted in the U.S. electric power industry.

The factors described above should not imply that retail competition cannot work, or that it will not work in the future for the smaller electricity customers. The results do imply, however, that the model for retail competition in which marketers would be assumed to approach small customers on an individual basis – customer by customer – may be longer in coming than many policymakers had assumed, at least without some new structures in place. It implies, also, that there may be value in re-examining this model for retail competition for the smaller customers, looking at approaches used in Oregon, Ohio, Maine, New York or other states. The next section reviews a number of different policy approaches.

B. STATE APPROACHES

Leaders in individual states took distinct approaches to restructuring their electric industries. These approaches took into account their own visions of how they thought markets would develop, as well as their own priorities and schedules. Perhaps most importantly, the plans varied according to the unique history and situation in each state. This section outlines the approaches that many states took to restructuring their industry, and offers some models that other states may consider. It is divided into three major sections that focus on:

- Managing the transition from monopoly to competition;
- Serving customers who choose not to choose; and
- Systems to permanently transform the market.

Managing Transition from Monopoly to Competition

State policymakers established systems that they hoped would bridge the gap between state regulation and competition. These systems had to protect customers while the markets got established and before consumers chose an alternative provider, and systems had to address industry concerns over the value of investments made under the regulated system – especially the investments the industry feared would lose value. These investments became known as transition costs.

States deal with transition costs

The short definition of transition (or stranded) costs is costs that utilities were recovering in the regulated system that they could not recover in a competitive market.[32] High priced generation is one example, though there are other categories.

Because of their magnitude, stranded costs created a great deal of political tension. The arguments came down to fairness and equity compared to economic efficiency. In the end, most states opted for the political solution. In general states allowed utilities to recover all or some significant portion of their stranded costs and gave utility commissions guidance as to how to decide what was or was not recoverable. This political solution often meant a series of compromises about the definition of stranded costs, the categories of costs to be recovered, the amount allowed for recovery, the length of time costs could be were recovered, and the way transition costs were recovered.

Almost every state legislature chose a definition of stranded costs that referred to costs that were legitimate, net, verifiable and unmitigable. Utility commissions were left to decide on the exact definition of each of those terms. "Net" referred to stranded costs that were determined on a company-wide basis, so assets that increased in value would offset the assets that decreased in value. "Mitigable" referred to the idea that utilities would attempt to reduce their stranded cost exposure as much as possible before claiming stranded costs. Utilities might try to re-negotiate above-market power supply contracts, for instance.

California's utility commission, for example, refined the legislative guidance that California A.B. 1890 offered by allowing utilities to recover their stranded costs through the difference between the wholesale prices available on the open market and the frozen retail rates that the utilities were

[32] For example, a long-term power supply contract might deliver at seven cents per kWh. If comparable power is available for five cents per kWh and is likely to remain available at these terms for the duration of the contract, and the utility transitions to competition, stranded costs mount at a rate of two cents per kWh. The utility's stranded cost of two cents per kWh results from the fact that the utility would have to match the cost structure of the five cent provider. If the stranded costs are great enough, inaction would threaten the solvency of the utility. State law and regulation allow the utilities to recover these stranded cost charges.

allowed to charge.[33] The state referred to this difference as the "competition transition charge," and all customers paid this charge on their regular utility bill. California's rate freeze in each service area remained in place until all the stranded costs were paid off, so low wholesale prices meant a quicker stranded cost recovery.

Most states adopted a similar approach; the norm became a non-bypassable charge imposed on all utility customers. The differences among states related primarily to the method of calculating stranded costs. Some states, like California, used an administrative determination of stranded costs. Others attempted to gather some specific market data, preferably based on sale prices for the assets in question. Massachusetts, for instance, established an administratively determined stranded cost number, but then adjusted it downwards once utilities sold their power plants for much more than had originally been anticipated. Because stranded costs calculations depended on not only an estimate of the value of power plants, contracts and other assets under utility control, but also depended on a comparison with an estimate of future market prices, any stranded cost estimate had a substantial element of uncertainty embedded in it. As a result, many states opted to adjust the stranded cost recovery periodically.

California took another approach to stranded cost recovery known as securitization. Securitization allowed the issuance of bonds based upon the legislatively guaranteed future stream of payments from the competition transition charge. Since the legislature and the Commission had guaranteed that the competition transition charge (and therefore the underlying revenue stream to pay off the bonds) would remain in place, these bonds received a high rating and a low interest rate. This low interest rate helped the state to finance a 10 percent rate reduction for small customers.

Securitization was controversial in California and elsewhere. Some consumer advocates objected to it because it gave utilities an immediate, up-front cash payout from their stranded costs and it removed any future risk that the utilities might not later receive that money.[34] Many utilities favored the idea of securitization for the same reasons. Securitization also had the effect of lowering the total stranded costs because they could be financed at a lower interest rate than was otherwise available. In the end, few states allowed securitization and few utilities took advantage of its provision.

To assure that all customers participated in stranded cost recovery, policymakers considered exit fees. The issue comes up generally when a customer becomes interested in on-site generation and severing its connection to the grid. On-site generation can be an opportunity to install a very efficient and comparatively clean energy system. An exit fee is designed to collect from the customer some or all of the embedded costs the utility incurred to serve that customer. Opponents of exit fees point out that the customer can go out of business or move, having the same effect on the utility, but with no exit fee. They also point out that self-generation was

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[33] Thus if wholesale prices were 3 cents per kWh and the retail price they were allowed to charge was 5 cents per kWh, they would recover two cents for each kWh they sold. If wholesale prices floated downward to 2 cents, their recovery would increase to 3 cents per kWh, and if wholesale prices went up to 4 cents, their recovery would shrink to 1 cent per kWh.

[34] Traditional regulation provides an "opportunity" to recover prudent and reasonable costs. Securitization became a guarantee of recovery. One less controversial use of securitization occurs when securitization reduces the cost of utility power contracts with independent power producers derived from PURPA. These are distinct because utility discretion and management are largely absent due to the public policy influence that led to the contracts in the first place, and disallowance risk is very small.

possible prior to the transition and no exit fee would have been due. Exit fees often more than consume operational savings customers expect from on-site generation.

Protections for non-choosing consumers

It turns out that one of the most important factors in the development of retail competitive has been how states treat the customers who do not choose an alternative provider. These regulated systems for provision of default service turn out to be critical to the outcome of what some people term “deregulation” policies.

Most states recognized from the outset that they could not expect retail power markets to take off quickly, and that some transition period would be necessary to phase in competition. As a result, states tended to offer a combination of rate freezes or mandated rate reductions over a specified period of time. These rate freezes for the retail customers co-existed with retail choice – meaning in many situations that customers who bought from a competitor would be leaving the protection that the rate freeze or reduction afforded them.

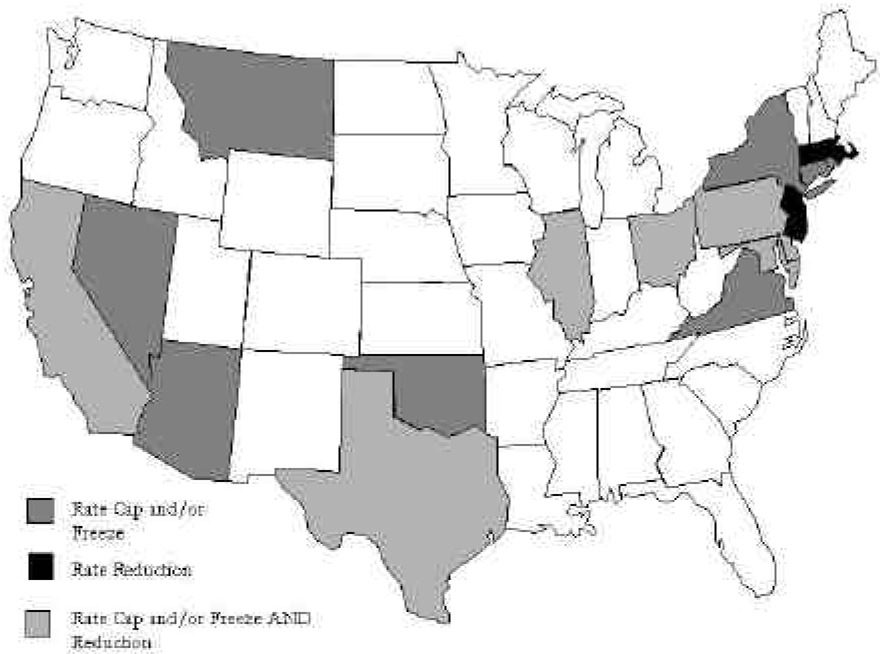
These rate freeze and rate reduction policies have been controversial since they have had a dampening effect on the ability of competitors to enter power markets. Yet they have also offered immediate and tangible benefits to consumers. They have in effect forced policymakers to face a choice between two policies:

- to offer immediate benefits to consumers and provide them security and low prices even if they do not choose a new provider, or

- to encourage competition by making the rates that that non-choosing consumers pay less attractive (higher) with the expectation that markets will operate to reduce electricity prices over time.

The following map, figure 8, illustrates which states offered an immediate rate reduction or rate freeze.

Figure 8. States with Rate Caps, Reductions, and Rate Freezes



Source: National Conference of State Legislatures

Serving Customers Who Choose Not To Choose

Treating different customers in different ways

Many states opted for complex models for offering continuing service to non-choosing customers, dealing with issues beyond a simple rate reduction or rate freeze. Seven examples from Montana, Nevada, Oregon, Pennsylvania, Texas, Massachusetts and Maine provide alternative approaches to serving consumers who did not choose an alternative provider (or in some cases serving different classes of customers in different ways).

Four models, with variations, illustrate the major approaches used thus far: (a) the incumbent utility continues to provide service under a rate that essentially passes through the utility's wholesale costs of power; (b) the utility remains a service provider to some customers but not to others; (c) the utility continues to provide service but does so under a rate structure designed to gradually wean customers away from utility service and towards market-based prices; and (d) the privilege of serving non-choosing customers is bid out, while the utility's role is to deliver power.

Many state policymakers assumed these structures for serving the customers who did not choose a competitor to last for a limited time, through a transition. That transition has turned out to be longer than most utilities or state policymakers expected and, as a result, has become an important policy issue. The states discussed below illustrate the three major approaches to serving the non-choosing customers.

Utility service to customers: Montana

Montana

Montana gave responsibility for serving the non-choosing customers to the old utility service provider, Montana Power Company. This service provider was required to offer service at a capped rate through a transition of about five years and set to expire in July of 2002. This fairly common approach was modified during the 2001 legislative session when the legislature extended the transition through 2007 and assigned the role of default provider to Northwestern Energy, the company that had since bought the transmission and distribution assets of Montana Power Company. Since Montana Power Company had also sold all of its generating assets to PP&L Montana, Northwestern Energy was required to secure a portfolio of generating resources through a bidding and negotiation process, subject to approval by the Montana Public Service Commission

Utilities serve some customers, competitors serve others: Nevada and Oregon

Two states – Nevada and Oregon – explicitly treat small customers differently from large customers. The two approaches differ, but both take as a fundamental assumption that, at least for the foreseeable future, the smallest customers are unlikely to participate in competitive power markets. The larger customers by contrast are likely to attract the attention of marketers and are likely to invest the time required to choose among competing offers. The experiences of most states that have allowed retail choice thus far – in which few small customers chose an alternative provider and many large customers did so – served as a backdrop for Nevada and Oregon's decisions.

Nevada

Nevada passed its restructuring act in A.B. 366 in 1997 but it was not set to take effect until December 31, 1999. The Public Utilities Commission was allowed to delay this date if the commission deemed it to be in the public interest – which it did – through 2001. Between those dates, however, California's power market failed and Nevada worried that its next-door neighbor's problems would spread eastward across its boundaries. As a result, the legislature in 2001 passed A.B. 369, which made some significant changes to A.B. 366. When the utilities in the state were about to voluntarily divest their power plants, the legislation stopped that divestiture in its tracks. And although all retail customers were soon set to have the option to choose a power provider, the legislature passed a separate bill that closed down the market for all the smallest customers, defined as those customers under 1 MW.

At one point in its deliberations the legislature had considered the possibility of closing down the markets for all customers, including the largest customers. But some mining and gaming companies asserted that they were well along the way to finalizing a contract to purchase power from one of the competitive power providers. As a result, the legislature elected to leave to the largest consumers the option to choose an alternative service provider. As of early 2003, 11 mines and gaming casinos had applied for permission to leave utility service, although none had actually done so.

Oregon

Oregon approached electric industry restructuring from a different perspective from that of many states with higher power costs. The legislature was concerned that power markets might not attract competitors for the smallest consumers in the state because of the relatively small savings that would be available in such a low-cost state. The legislature allowed the largest consumers to choose an alternative provider if they desired and but did not allow small consumers to choose a competitor.

But Oregon's program was different from Nevada's because it gave consumers a choice of electricity product – even if not a choice of electricity provider. The Oregon legislation specified that small consumers be offered a portfolio of products, including a basic generation service product, an environmentally based product and a market based product.

In practice, the implementation of Oregon's law has been more nuanced and perhaps more complex than the legislature originally envisioned. There are several key elements to the Oregon program.

The Portfolio Advisory Committee. The Oregon Public Utilities Commission established a Portfolio Advisory Committee to address the details that inevitably come up in a new program. This committee now consists of members from several sectors including the utilities, consumer and environmental advocates, and state agencies. Energy marketers who would later be bidding for the privilege of offering products to retail customers are not included in the portfolio advisory committee since the committee might be discussing and voting on matters that directly affect bids. The Committee makes recommendations to the Commission, which approves or disapproves the recommendations, or may approve the recommendations with alterations. Although the Portfolio Advisory Committee's recommendations carry a heavy weight, they do not bind the Commission in any way. The Committee has turned out to be an important forum to work out details of the program before asking the Commission to address them.

The products. Oregon's utilities serve approximately 1,200,000 customers. Of this customer base, the small customers which may not choose from an alternative provider, have the option of choosing from four or five products, depending on which utility serves them. Following is a brief discussion of these products:

a. *The Fixed Renewable Option*, through which customers pay a surcharge of $3.50 over their basic service rate to buy renewable power in 100 kWh blocks. The two programs under this option are run by the utilities and are outgrowths of their previous green energy programs. The funding that the extra charge generates goes towards acquisition of new renewable resources. As of August 1, 2002 approximately 9,000 customers has signed up for this option.

b. *The Renewable Usage Option*, which is billed at a per kWh rate of an additional 0.8 cents per kWh, is totally green. The Oregon Public Utilities Commission set a 50 percent standard for renewable resources, of which 15 percent must be new renewable. The remaining 50 percent must meet carbon and emissions standards. In practice, all of the resources represented under this option are renewable. The provision and marketing of the service were competitively bid out separately, with Green Mountain Energy selected to market and provide the service. As of August 1, 2002 approximately 10,500 customers had signed up for this option.

c. *The Habitat Option* is structured similarly to the Renewable Usage Option but with an extra 0.99 cents per kWh charge to support fish habitat restoration. As of August 1, 2002 approximately 4,200 customers had signed up for this option.

d. *The Time-of-Use Option* offers per-kilowatt-hour prices that vary depending on the time of day. As an example, on-peak is defined as between 3:00 and 8:00 PM in summer and 6:00 AM to 10:00 AM /5:00 to 8:00 PM in winter, on weekdays. Portland General Electric, an investor owned utility, offers this option. The generation component of the rates for on- off- and mid-peak service are as follows:

- On-peak: 7.751 cents/kWh
- Mid-Peak: 4.651 cents/kWh
- Off-peak 2.843 cents/kWh

These rates are for generation service only. An additional charge of approximately 2.596 cents/kWh charge is assessed for transmission and distribution, as well as a fixed customer charge of $10 to $16.

Because electricity is more expensive to produce during the day, at peak hours, the electricity system and customers can benefit through lower total costs in the long run if customers shift their usage from on-peak to off-peak periods. Depending on the generation mix, (i.e. which power plants are used at what time of day, and their emissions profile) this pricing program can also reduce emissions into the air, if the generation used at peak periods is dirtier than the generation used during off-peak periods. Finally, it also has the potential to increase energy efficiency if people reduce their overall usage – rather than shift all their usage to later periods of the day. This option also requires installation of advanced meters. As of August 1, 2002 slightly more than 3,000 customers had signed up for this option.

e. *The Monthly Market Option* gives customers a price that varies each month, over a 12 month period. Customers that sign up for the option are given a year-long, monthly list of prices that they will be paying. Pacific Power & Light, the only provider of this product, develops those prices based on a forward price curve, and has the opportunity to make commitments to acquire power at these prices to serve subscribing customers. Customers commit to stay with this program over the course of the 12 month period. As of August 1, 2002 1,432 customers had signed up for this option.

In general, interviews with various parties, from consumer advocates to power marketers to utilities to utility commissions, indicate a positive impression of Oregon's program.

Other states are considering variations of the Oregon program, taking advantage of the lessons from the program. These lessons include:

a. Most parties in Oregon agree that there may be too many products offered. Oregon's initial legislation indicated that the utilities should offer a basic generation (similar to standard default supply) option, an environmental option and a market based option. Oregon's combination of three environmental options shows in part the history of utilities that did not want to end their own renewable "green pricing" programs as well as a particular local interest in fish habitats.

b. In order to assure ongoing analysis and input into the program, establish a committee similar to Oregon's Portfolio Advisory Committee to oversee and make recommendations to the Commission on the direction of the program, products to be offered, contract terms etc.

c. Use competition in delivering these services where possible. Oregon elected to have the utilities bid out the privilege of marketing and delivering two of the three green products. The result has been a collaborative agreement between the marketer that won the bid, Green Mountain Energy, and the utilities. This element of the program brings a new party to the delivery of products to the marketplace, with a bottom-line incentive to make the program work. It also provides a safe environment in which a marketer may be able to test new products. As a program develops, it may be possible to bring in new marketers to offer products through this regulated program.

d. Monitor and evaluate the program on an ongoing basis in order to be able to change it as circumstances warrant.

e. Another option to consider would be to have the renewable product subject to less price volatility than a fossil-fuel-based product. Such a price guarantee is possible in a regime in which there are no fuel costs. It may also serve to attract more customers to the product option. Customers would be, in essence, paying more not only for the renewable product, but also for price security.

Large customers. Large customers in Oregon have the option of buying power from competitors, although by the end of 2002 no large customers were in fact buying from competitors. Oregon officials attribute this lack of retail market activity to the fact that the utilities offer a choice of either a fixed price or a price that varies monthly, thus approximating some of the opportunities that power marketers might be able to offer large customers. These two approaches that that treat different customers in different ways may offer one model for states interested in pursuing competition, but still leaving some of the protections of the regulated market in place for the smaller consumers.

Bidding out the privilege of serving customers: Pennsylvania and Maine

Pennsylvania

Pennsylvania initially gave responsibility for serving the non-choosing customers to the utility providers. Legislation allowed, and regulation later required, that several of the utilities bid out the privilege of serving a portion of the non-choosing customers. Several utilities, including

PECO, GPU, PPL and Allegheny did issue bids, but only PECO received a responsive offer from the competitive solicitation -- and was only satisfied with that offer after entering into a one-on-one negotiation with the two successful bidders. Two factors contributed to the lack of responsive bids in GPU, PPL and Allegheny territories: (1) the volatile wholesale market at the time and (2) the relationship between wholesale market prices and retail prices offered to the customers who did not switch providers. These retail prices in the GPU territory were set at a level that was too low to permit marketers to both beat the regulated price and make a profit for themselves.

PECO's situation was different, because the price for non-choosing customers (set at the time at 5.87 cents per kWh) was high enough in relationship to wholesale market prices that the marketer, New Power (a subsidiary of the now-bankrupt Enron), was able to offer a two percent discount to the 16 percent of the total customers whose load was put out to bid, and perhaps make a profit for itself.

When wholesale market prices spiked in 2000 and 2001, New Power became unable to make a profit while continuing to offer service at the discounted price it had contracted. New Power's own financial problems arising from its Enron ties exacerbated the company's inability to handle market volatility. After several attempts to turn the customers back to PECO, the Pennsylvania commission and PECO agreed that PECO would take the customers back and continue to serve them at the discounted rate. New Power has since gone out of business. The other company, Green Mountain Energy that had agreed to serve 35,000 to 40,000 of PECO's customers continues to do so.

Although in part the result of extraneous problems at the parent company Enron, this situation shows the close inter-relationships of wholesale and retail power markets.

Maine

Maine took a different approach to serving customers who did not choose a new provider. Instead of assigning them to the old utility, Maine's Public Utility Commission bid out the privilege of serving blocks of consumers to competitive providers. In Maine, the utility commission, acting on legislative authority, puts out for bid the load of several customer classes (residential, small commercial, large commercial and industrial loads) in each utility territory. Competitive suppliers respond in their bids with price and terms for how they will serve the load. The Commission either accepts or rejects the bids, although it may also elect to narrow the number of bidders, and negotiate with the remaining small number of bidders.

The accepted bids are not subject to a contract-by-contract prudence review. The marketer, by submitting, and agreeing to, a bid price is then tasked with the job of assuring that it can deliver at that price. It is assumed that the marketer has developed a portfolio of not only generation, but also financial hedges to assure that it will be able to deliver on its proposed price. Winning bidders are bound by force of law to deliver upon their promised bid. They do not sign a contract with the Commission in Maine, since the flow of dollars does not involve the State.

The Maine Public Utilities Commission reviews the bids that marketers submit to it. The Commission had initially hired a consultant to help analyze the bids, but now has gained enough expertise that it does not need outside assistance. It remains a significant task for the Commission, over a period of approximately four months for three to four people. Maine is now on its third set of default service contracts, which provide all default service power for three years.

The distribution utility can charge the marketer for billing and collection services. As an alternative, the marketer could bill and collect, while charging a fee to the utility for such services.

It is also important to note that this policy option does not necessarily shut down the ability of small consumers to choose an alternative provider; the ability to choose can co-exist with this approach.

Encouraging Marketers: Texas, Massachusetts, Pennsylvania and Ohio

The approaches discussed above illustrate three different methods that states use to continue to provide electricity service to the customers who do not choose an alternative provider. Some states took the next step of not only addressing the needs of the customers who did not switch, but tried to encourage marketers to operate in the retail power markets.

Assigning customers to marketers: Texas

Texas

Texas took a variant on the Montana approach, assigning any customers who did not choose an alternative provider to the utility marketing subsidiary. Thus, the customers who did not choose an alternative provider were still switched to a new provider – but that provider was the subsidiary of their old utility company. Customers could still switch to a competitor.

Different generation rates for different non-choosing customers: Massachusetts

Massachusetts

Massachusetts officially authorized restructuring of its electric industry on November 25, 1997, when the governor signed H.B. 5112. The markets opened to retail competition on March 1, 1998. Customers who did not choose a competitive, non-utility provider received a ten- percent rate reduction in 1998, which increased to 15 percent in 1999.

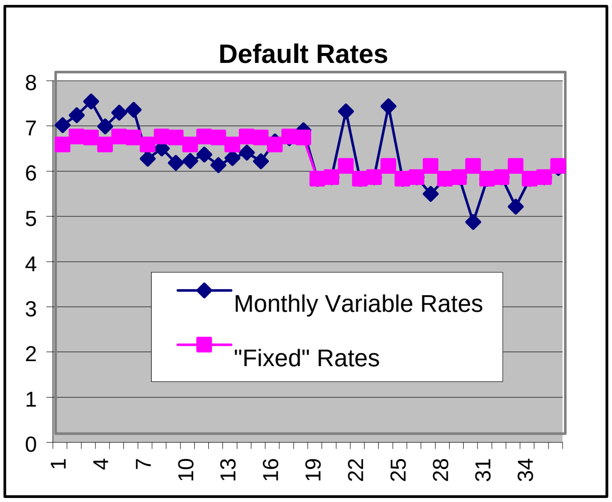
Massachusetts gave the responsibility for serving its non-choosing customers to the incumbent utility providers. The unique part of the Massachusetts approach lies in the fact that it assigned customers into one of two classifications: default service and standard offer service.

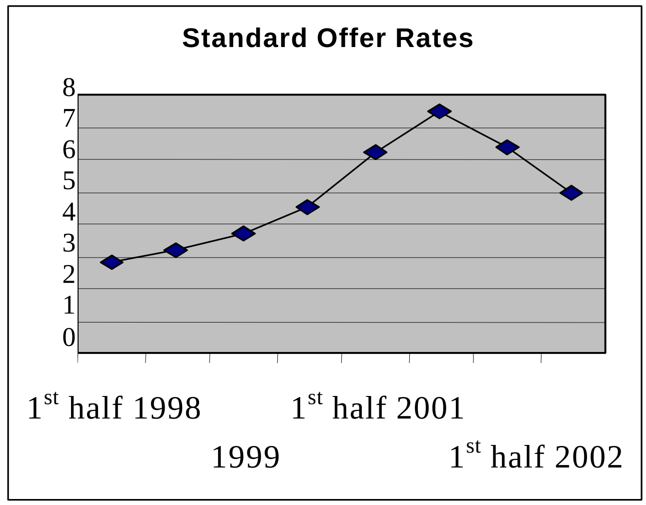
Standard offer service originally served all the non-choosing customers, and was designed to be a stable and even discounted rate from the pre-restructuring rates. Standard offer is set to be phased out by mid-2005, after which all customers will be served by either a competitor or by another rate class known as default service. Default service customers are either those who have left standard offer and then returned to utility service or those who are new to the utility's service territory.

Default service is meant to more closely approximate market prices. In Massachusetts, customers can choose from two default service pricing options: (1) a variable pricing option in which the price changes monthly; and (2) a fixed pricing option in which the variable monthly prices are averaged and remain constant for six-month periods. The contrasting prices are illustrated in the graphs below. The chart on the left of figure 9 illustrates the default service pricing in its two forms, variable and 6-month-fixed. The chart on the right illustrates the standard offer price. Note that as it gradually rises, customers will be encouraged to move off the standard offer and towards competitive offerings. The steep rise in both prices in 2001 reflects fast-rising wholesale prices at the time (see, also, figure 5), which were passed through to some degree in these rates as they were adjusted every year or six months.

Massachusetts offers three generation service options available to consumers: (1) competitive generation service, provided by competitive suppliers; (2) standard offer service, provided by distribution companies; and (3) default service, also provided by distribution companies. The price that the customer pays for generation service is dependent on the type of service the customer selects.

Figure 9: Massachusetts Default Service and Standard Offer Rates (cents per kWh)





Encouraging marketers and customers to switch

A small number of states tried to design systems that encouraged marketing to small customers. Pennsylvania did so by examining the prices that non-choosing customers paid in relationship to what marketers could offer. Ohio and Massachusetts attempted to address the customer acquisition costs and to reduce the amount of time and effort a customer would have to expend to switch providers.

<u>Price to compare: Pennsylvania</u>

Pennsylvania

Pennsylvania addressed the price of power to customers who did not choose an alternative provider by setting up a "price to compare." The price to compare was not based on the wholesale price of power (as it was in many states) but instead took into account some of the marketing costs that marketers would have to employ in order to compete with the utility-provided power. The result of this system was to create a rate that for some time, at least, was high enough to allow marketers to both beat the price to compare, to buy power off the wholesale market and to make a profit on their own sales. Some criticized this rate as a "subsidized," artificially high rate. The effect, however, was to stimulate competition in some parts of the state.

This rate was capped in order to give consumers protection against skyrocketing power costs. As a result, when wholesale power prices jumped higher in 2001, many marketers were unable to meet the capped price to compare, and so customers switched back to the regulated rate.

Aggregation: Ohio and Massachusetts

Another approach to encouraging retail markets is known as opt-out aggregation. Aggregation does not take the approach of giving incentives to consumers to switch, nor does it specifically address marketing costs or the pricing of default service. Instead, it gives otherwise small customers who possess little buying power on their own, much greater buying power in an aggregated group.

Opt-out aggregation is a public process that allows a municipality, county or other local branch of government to assemble the electric load of all or a part of the customers within its jurisdiction, and bid that load out to the best bidder. The citizens of the municipality, township, county or other government aggregator are assumed to be part of the buying group unless they affirmatively say that they do not want to be part of the group. The citizens of the municipality have the opportunity to participate in the public process that determines whether or not the town will actually act as an aggregator. They then have the opportunity to either participate, or not participate, in the aggregated group.

Opt-out aggregation is distinct from opt-in aggregation, in which an aggregator, such as church, a union, a not-for-profit or a for-profit group arranges a power purchase on behalf of its members. Such aggregation requires the church, union or other aggregator, to persuade each customer to affirmatively agree to be a part of the buying group. As an example from Virginia, the Retail Merchants Association is arranging such a bulk purchase for its member companies. In Massachusetts, the Housing and Education Finance Authority (HEFA) created a buying group of hundreds of non-profit electric consumers.[35] Opt-in aggregation is a higher cost means of assembling a large group of customers than opt-out aggregation.

Opt-out aggregation is also different from municipalization, in which a municipality operates the distribution system and either generates or purchases power in order to sell it to customers within the geographic boundaries of the municipality. Some parties, particularly investor owned utilities, claim that municipalization often involves significant tax advantages that result from government building power plants or taking title to power. Whether or not these tax advantages exist, opt-out aggregation is distinct, and places the government in the position of buying agent for its citizens. However the transaction and payments are between a power marketer (selected by the government aggregator) and individual customer. The government is neither buyer nor seller.

State law must authorize opt-out aggregation, and only three states have enacted such a law: Ohio, Rhode Island and Massachusetts. A Rhode Island law enabling opt-out aggregation was enacted late in the 2002 session, and has not produced results as of the publication of this publication.

[35] http://www.poweroptions.org

Ohio

Ohio officially authorized the restructuring of its electric industry on July 6, 1999 when the Governor signed S.B. 3. The phase-in to retail competition began on January 1, 2001 and a transitional period is scheduled to end on December 31, 2005.

Ohio's plan for restructuring is similar in many respects to that of other states, but differs significantly in its approach to providing service to small consumers because it allows opt-out aggregation. Opt-out aggregation has been responsible for the majority of residential customers switching to a new provider in Ohio.

Ohio's aggregation effort encompasses several sub-efforts, and should be seen in a broader context of four unique factors in Ohio

Special power allocation. The state created an allocation of "market support generation" (MSG) power to jump-start the market. MSG power was low cost power available only in the Northern Ohio, First Energy territory. First Energy made an allocation of 1170 MW of power at a discounted price of 3.1 cents per kWh that was available on a first-come first-serve basis to marketers that had a specific list of retail customers who would receive the power. The allocation of the MSG power created some controversy, since many marketers or government aggregators claimed that they did not have sufficient time to assemble a list of retail customers who would receive the power before the allocation disappeared.

MSG power was available only in Ohio, and affected the discount levels that some aggregators were able to offer. The largest aggregation efforts were completed without MSG power.

Utility incentives to shed customers. Utilities in Ohio have a strong incentive to shed customers embedded in their restructuring law. The law conditions stranded cost recovery on the loss of at least 20 percent of utility load. Opt-out aggregation became a swift way to achieve this threshold. This affected First Energy in particular, because it had the highest stranded cost levels.

Geography. Ohio's power system has two distinct areas. One is expensive northern Ohio. The other is the relatively inexpensive rest of the state. The average cost of power in First Energy territory is considerably higher than in southern Ohio.

As a result of these cost differentials, most aggregation activity and indeed most retail activity have taken place in the northern part of the state. Since mid-May of 2002 several additional municipalities outside of northern Ohio passed opt-out referendums, and the progress of those efforts will be indicative of the attractiveness of aggregation outside of the more expensive northern Ohio region.

The Ohio PUC reports in its April, 2002 report on the progress of electric industry restructuring that aggregation accounts for approximately:

- 85 percent of residential customer switching,
- 50 percent of commercial customer switching, and
- 25 percent of industrial customer switching.

Two aggregation efforts in Ohio illustrate the state's progress.

1) Parma, Ohio
Parma is a town of 90,000 in northern Ohio that was able to take advantage of MSG power both for city-owned facilities and the citizens of the town. Seven percent of the households opted out of the arrangement. Opt-out aggregation gave the citizens of Parma a 17 percent discount on their power prices, equivalent to some $60 to $75 per year for most residential households, depending on their usage.

The discounts that Parma's citizens received were larger than those available to many other aggregated groups because the city was able to take advantage of special and limited power discount. This type of discount is distinct to Ohio. Although Parma is sometimes cited as an example of how well aggregation can work because of the significant discount that the citizens of Parma received, it is important to remember the significant role that MSG power played in the city's ability to secure such as substantial discount for its customers. Without an MSG equivalent power discount, such a deal would have been impossible to replicate in the Ohio power market of the time.

In addition, it is worth noting that Parma apparently made a significant investment of close to $200,000 in acquiring and paying for the expertise to negotiate its power supply deal.

2) The Northeast Public Energy Council (NOPEC)
NOPEC is the nation's largest aggregated group. It took advantage of the Ohio restructuring law's aggregation provisions by combining not only the load of the citizens of a single municipality, but the combined load of many municipalities. It is now a buying group representing 97 cities or townships and more than 300,000 people.

Green Mountain Energy (the group selected by NOPEC to serve the aggregated customers) serves this aggregated group of communities under a six-year contract that offers a single price option at a discount from what customers would otherwise pay for power. The savings vary from one customer to another, and are as high as 15 percent for a few customers and as low as 1 percent for others. Typical discounts are approximately 2 percent. In addition to the price discount, Green Mountain's product is guaranteed to be cleaner than the average Ohio electricity product. It is a combination of 98 percent natural gas and nuclear and 2 percent green power, such as wind.

Massachusetts

Massachusetts was the first state to put opt-out aggregation provisions into its electric industry restructuring statute. Yet largely as a result of the state's low, regulated standard offer prices, retail competition resulted in less than one-half of one percent of customers receiving competitive supply. The story of aggregation in Massachusetts demonstrates difficulties in wholesale power markets, the problems that can result from very low regulated, retail prices and the importance of having a persistent and knowledgeable advocate.

After Massachusetts passed its restructuring legislation containing language allowing opt-out municipal aggregation, the Cape Light Compact began an effort to buy power on behalf of all customers in a 21 county area encompassing Cape Cod and Martha's Vineyard.

Cape Light's efforts began in the late 1990s, but it was not until 2002 that the Compact has finally worked out an arrangement with the state policymakers and with power marketers to offer product to customers. The problems in the start up did not relate to assembling the group to aggregate, but have related largely to a combination of wholesale and retail market issues.

Now some 40,000 customers are served in Cape Cod and Martha's Vineyard by Mirant, a non-regulated generation company formed by the Southern Company. This represents the single largest block of residential customers served by a single non-utility provider anywhere in Massachusetts or New England. Customers pay 4.89 cents per kWh as of May 1, 2002, and 4.79 cents per kWh beginning in May of 2003. This equates to savings that range from 11 to 22 percent, or between $3.50 and $7.00 per month for an average customer. In addition, the Compact offers its customers three green products designed to support both existing renewable energy facilities and new facilities:

- New Green - at an additional 1 penny per kWh to supports development of local renewable energy facilities;
- Blue-Green - customers pay to support existing renewable supply equivalent to 50 percent of their monthly usage at 7.185 cents per kWh, 0.5 cents per kWh of this is applied to support of new local renewable energy facilities; and
- Deep Green- customers pay to support existing renewable supply equivalent to 100 percent of their monthly usage for 9.935 cents per kWh, 0.5 cents per kWh of this supports new local renewable energy facilities.

Transforming the Market

States transformed the role and structure of the regulatory commissions

With the significant changes contemplated for the electricity market, it is not surprising that regulators also looked inward to reconsider their role in new electricity markets. Practices such a rate cases and integrated resource plans needed rethinking. New requirements for licensing and monitoring competitors were needed, as well as overseeing provider of last resort service and newly-designed public benefit programs.

In addition, as the next section explains, more of the regulators' attention became devoted to engaging in changes to the wholesale market.

While some thought that increased reliance on markets would allow regulatory staffs to shrink, that has not yet proved true. The new challenges of constructing working markets, plus the remaining regulatory responsibilities over continuing monopoly tasks, indicate that electric industry restructuring is unlikely to turn into an opportunity to scale back the cost of regulation.

New systems needed to deal with energy efficiency, renewable energy, research and development, and low income customer programs

Electric utilities had built up a substantial research and development effort by the early 1990s, and had also been investing a great deal of funding into energy efficiency, renewable energy and low income customer programs. When the power industry started its transformation to competition, these were among the first programs to be cut; they were long-term investments that did not mesh well with the utilities' short-term competitive strategies and their worries about stranded cost recovery. Some utilities were uncertain they would be allowed to recover these costs over time, as had been standard practice. Utilities' budgets for such programs fell precipitously: The budget for Florida Power efficiency programs fell by 53 percent, that of Central Vermont Public Service fell by 73 percent and that of PacifiCorp fell by 88 percent. Nationally, utility energy efficiency budgets fell by over 50 percent.[36]

State policymakers saw value in these long-term investments and sought ways to maintain or even boost funding for them. In some cases, state policymakers simply set a mandate for renewable energy or for continuation of low-income customer program. The state approaches were divided into two major areas: funding or mandates.

<u>Funding</u>

Seventeen states set up what is alternatively known as a system benefits fund, a public benefits fund or a universal system benefits program. These states wanted to maintain public purpose activities of utilities, recognizing that these should be addressed distinctly in a competitive environment. Whatever it was called, the fund was established through a fee placed on electricity customers' bills, no matter who was selling power to the customer. The fee was small for each customer, usually between one-tenth to two- or three-tenths of a cent per kilowatt hour and it was volumetric (based on electric use). Large numbers of customers each paying small amounts of money could raise a great deal of money for such programs. States dedicated these funds for public interest purposes generally described in competition legislation with varying degrees of specificity. In many cases, these funds replaced money that was embedded in the rates of the monopoly electric company to conduct research and development, deliver energy efficiency, or to do other public interest activities. In other cases, these activities were new. The following table, figure 10, describes the size of the fee and the amount of money it raised in different jurisdictions.

[36] Comparisons are from 1993 to 1997. Coequyt, John, Richard Wiles, *Unplugged: How Power Companies Have Abandoned Energy Efficiency Programs*, Environmental Working Group, 1998.

Figure 10: State System Benefits Funding and Term of Commitment Varies

State	Annual Funding: Energy Efficiency and Renewable Energy ($million)	Per Capita Annual Funding	Funding Duration
AZ	$ 24	$ 4.4	2001-indefinite
CA	$ 425	$ 12.1	1998 – 2012
CT	$ 109	$ 31.5	2000 – indefinite
DE	$ 2	$ 2.5	10/99 – indefinite
DC	$ 2 - 8	$ 3.5 / $ 14.0	2001 – indefinite
IL	$ 8	$ 0.6	1998 – 2007
ME	$ 17	$ 13.1	indefinite
MA	$ 147	$ 22.9	1998 – indefinite
MT	$ 11	$ 12.1	1999 - July 2003
NH	$ 7	$ 5.5	2001 - indefinite
NJ	$ 119	$ 13.9	2001-2008
NM	$ 4	$ 2.2	2007-indefinite
NY	$ 83	$ 4.3	7/1998 – 6/2006
OH	$ 15	$ 1.3	2001-2010
OR	$ 41	$ 11.6	10/2001 – 9/2010
PA	$ 13	$ 1.1	1999 – indefinite
RI	$ 16.5	$ 15.4	1997 – 2008
TX	$ 80	$ 3.7	2000 – indefinite
VT	$ 14	$ 22.7	2000 – indefinite
WI	$ 65	$ 11.9	4/1999 – indefinite

Source: American Council for an Energy Efficient Economy, May 2002

<u>Research, Development and Deployment</u>

Issues include:

- Covered fuels and technologies: A state can choose to focus entirely on renewable energy. Or, highly efficient technologies can receive support. In some states, home grown technologies may be targeted for assistance.

- Cost: A significant fund can accumulate even with a charge of $0.0001 per kWh.

- Management: As advanced technologies are complex and evolving, specialized advice in managing the funds is desirable. Also, patience to learn about the technologies is important to avoid wasting the funds.

There may be advantages for states with similar objectives to co-ordinate efforts.

Energy Efficiency

Some states not only recommitted to energy efficiency as part of restructuring, but also reorganized how the service is delivered. These states reassigned the role of delivering energy efficiency service to a statewide entity and away from the incumbent utility. There are different models that flow from local needs and preferences. Some states that have not embraced retail competition, including Vermont and Wisconsin, have restructured the way energy efficiency is delivered. The different models include: putting programs under the control of a state authority or agency (ME, NY, WI); assigning the programs to a non-profit agency to administer (OR); and bidding out the service to a contractor (VT). In what might be called a hybrid structure, Connecticut has created the Energy Conservation Management Board that governs energy efficiency funds. The distribution utilities and others are eligible to make proposals to use of the funds. The management board includes state officials, utilities, and others with useful perspectives.

Low Income Programs

Particularly when it came to low income customer programs, many state legislatures felt it was important to offer a more direct and mandated approach. California (AB 1890) required that all low income programs be funded at not less than their 1996 levels. Rhode Island also required that all low income customer programs continue in force.

Renewable Portfolio Standard

Twelve states set up a requirement that electricity retailers operating in the state include as part of the resource mix some percentage of renewable energy. For example, in 2002 California imposed a requirement that 20 percent of all power sold through investor owned utilities in the state be generated from renewable energy by 2018. Renewable energy is usually defined as energy from wind, solar, geothermal, biomass and sometimes hydropower resources. Maine set a requirement that 30 percent of all power sold in the state be generated from renewable energy sources. Although that number is higher than that of most states, Maine used the portfolio standard to protect its already-existing renewable generating plants; the state already had in excess of 30 percent of its power generated from renewable resources. Massachusetts, on the other hand, designed its RPS specifically to promote new renewable resources. This approach promotes competition among qualifying renewable resources, distinguishing this policy from long term avoided cost-based contracts under PURPA. The following chart, figure 11, illustrates which states have a renewable portfolio standard.

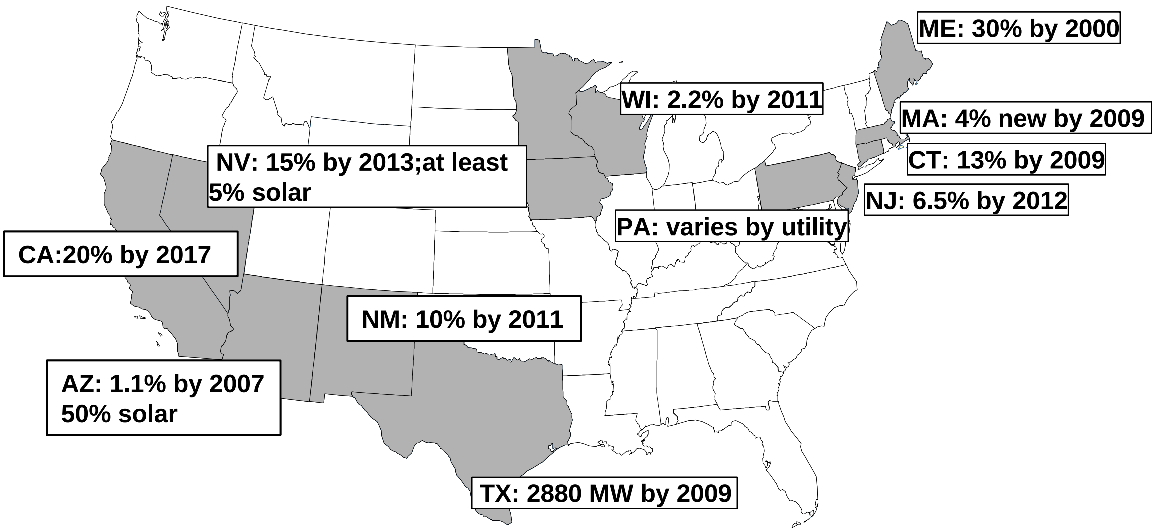
A portfolio standard tends to encourage competition among qualifying resources, providing a measure of assurance to consumers that the renewable power target will be achieved while minimizing cost.

Issues to consider with the portfolio standard:

Percentage required

What percentage of the retail load should be served with renewable resources? In general this decision is based on an ultimate goal of renewable energy potential in the state and the costs of meeting some percentage of that load with renewable resources. The percentage could be specified to grow over time to encourage new resources.

Figure 11. States with Renewable Portfolio Standards



New load or existing load covered

It is possible to structure a portfolio standard to cover only new load growth. While administratively awkward, this poses less of a competitive threat to existing generation and focuses the policy on adding new renewable power to the electric system.

Covered entities

It is possible to structure a portfolio standard to cover only certain entities, such as investor-owned utilities, default suppliers, rural cooperatives etc. Unequal requirements can lead to unfairness.

Covered resources

It is important that the definition of covered resources is clear. The resources selected by policymakers can be driven by such motivations as sustainability, air quality, and support of in-state resources or industries. In general, a renewable portfolio standard covers solar, wind, biomass and sometimes geothermal resources. Some allow small hydroelectric, but rarely allow large hydroelectric.

Dedication to wholesale markets would lead to allowing out-of-state resources to qualify. Enabling out-of-state renewable credits to qualify requires a system to assure that the credits are being used only once. A system in use in New England is enabling easy transaction of credits within the region, but is not allowing a free flow of credits from outside the region.[37]

A state, however, could make out-of-state resources ineligible, or discounted in value if policymakers are motivated to favor in-state resources. Any distinction between in-and out-of-state resources would have to pass muster with the U.S. Constitution's Commerce Clause.

A standard that allows only new resources to qualify will have more of an effect on new development, while one that allows pre-existing resources helps those resources be more competitive. The former approach relies on developers to deliver new capacity. States can establish sub-categories, a specific requirement for solar energy, for example, within a more general renewable portfolio standard.

"Green Tags"

Green tags represent a market based system that allows the retailers upon which the portfolio standard burden falls to avoid having to immediately build new renewable energy facilities. Instead, the retailers purchase credits for sale from other renewable energy facilities and providers. Thus, the credits may not immediately result in new renewable energy facilities being built but would, instead, result in resources built in the regional market. The credits may be the least expensive means to structure a portfolio standard, since they should take advantage of the most cost effective and best resources available.

Penalties

Penalties for non compliance with the portfolio standard are one way that states have ensured compliance with the standard. In general, the penalties have been set at a level that is higher than the cost of complying with the standard. Funds collected as non-compliance penalties are generally devoted to renewable power development and deployment.

Phase-in period

Portfolio standards can be phased in over a period of five to 10 years or longer.

Cost

The Texas portfolio standard is estimated to cost approximately five cents per month per customer. The Energy Information Administration estimates that the portfolio standard implemented on a national, 10 percent basis, would result in "small" cost increases. This study also indicated that the increased demand for renewable energy would offset demand for natural gas, thus relieving pressure on natural gas prices.

The cost of a portfolio standard depends in part on its structure, but largely on the renewable resources available compared with the size of the requirement. A balance can lead to a requirement that imposes little or no cost on consumers at large.

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[37] According to Green Mountain Energy Company, this is one reason for exiting the retail market in Connecticut. *Green Mountain Energy Company Pulls Plug on Connecticut*, press release, January 17, 2003.

The Portfolio Standard as a Mandate

Some states have rejected the idea of a portfolio standard because it is a mandate on retail providers. Others point out that although it is a mandate, it is imposed equally upon all electricity providers, and replaces equivalent mandates on monopoly electric companies.

<u>Emissions Portfolio Standard</u>

Two states, CT and MA, have added a second portfolio standard to address air quality. In an emissions portfolio standard, the energy sold must, on average, not exceed a specified level of pollutants per kWh. The pollutants included are NO_x, SO_2, and CO2. New England has put in place an information system that tags all kWh used in the region, and this system enables load serving entities to gather this information and report it to regulators and consumers.

Massachusetts law requires an emissions portfolio standard. Rules to implement it are due in 2003. Issues to consider include:

Gases covered

Massachusetts includes NO_x, SO_x, and CO_2. These emissions are routinely measured at power stations of significant size. Other emissions could be included if measurement is a reasonable task.

Ceiling

The requirement would be set with an objective to achieve some level of overall emissions from electric use. Close coordination between energy and environmental regulators is desirable.

Tradable credits

As with renewable credits, a market in emissions tags can emerge to enable retail sellers of electricity to meet emissions portfolio requirements in an efficient way. This practice would also allow sellers interested in marketing cleaner forms of energy to meet their higher standards more efficiently.

States set up generation information disclosure systems

When New Hampshire and Massachusetts authorized short-term retail access pilot programs in the mid-1990s, marketers flocked to those states with competitive offerings. Some offered products to New Hampshire and Massachusetts customers that gave a small discount on electricity. Many, however, offered a product that claimed some type of green, environmentally friendly attribute. Consumers seemed to be interested in a clean power choice.

As retail markets developed in other states, marketers continued to differentiate their products based on environmental attributes. With the availability of products claiming green attributes, many policymakers expressed concern that marketers might make false claims and present confusing information in order to make a sale.

One solution to this problem was to require some type of uniform disclosure of environmental attributes of the electricity product. Customers could choose to buy an electricity product based on its emissions attributes or based on the fuels used to produce power. Electricity labels, looking in some respects like food nutrition labels – designed in a clear, readable format – described the price, terms, fuel source and emissions profile of the electricity product that consumers purchased. This disclosure policy was popular with consumer advocates because it offered a clear and uniform means to communicate price and terms of electricity products. It was popular with environmental advocates because it lent credibility to the green power market. Many environmental advocates also held out hope that disclosure policies would serve to educate consumers about the fuels used to generate electricity, and perhaps prompt them to ask for more renewable energy products.

Disclosure is most reliable if some independent institution tracks the sources of power. Such a system has been created in New England[38] and is under development elsewhere. Expectations regarding disclosure should be clear. Disclosure labels, for instance, do not claim to track emissions from the power physically delivered to the customer. Rather, it tracks the contractual flow of dollars from the customer to generators from which the load serving entity has acquired the attributes of power. As a result, if a customer buys power from a source claiming to be 100 percent "green," it means the supplier has contracted to buy power attributes from a source somewhere in the relevant power grid that is "green." The actual electrons serving the individual customer will almost certainly be generated from the same power plants as before.[39]

States set up systems to address market power

When many state policymakers looked hard at their power industry they saw one in which there was cause to worry about the ability of a small number of parties to control market prices. They further observed that even the ability of a small number of parties to control market prices for a small number of hours during the day could be significant. The power market looks very different at 3 in the morning from at 3 in the afternoon; more power plants are at work and the system is working much harder at 3 in the afternoon (especially on a hot day) and indeed power is much more valuable at that time of day. This is especially true when reserve margins are smaller, and when deliverability constraints create local shortages.

As proof emerges showing the complex ways in which now-bankrupt Enron and other companies found ways to manipulate electricity markets, it is becoming clear that market power, and its effect on prices, is very important for policymakers to understand and to address in electricity markets. It is also clear that at least some of what one state – California – did to try to address market power did not work.[40]

There are nonetheless several different approaches to addressing different types of market power that many states have adopted. This section reviews a small number of important examples but does not attempt to offer a comprehensive discussion of the topic. There are two types of market power that concern most policymakers: horizontal and vertical market power.

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[38] http://www.nepoolgis.com

[39] See Sedano, Richard, *Electric Product Disclosure: A Status Report*. National Council on Competition and Electric Industry. 2002. http://www.ncouncil.org

[40] Brown, Matthew H., California's *Power Crisis: What Happened? What Can We Learn?* National Conference of State Legislatures, March 2001.

Horizontal market power refers to a single company owning or controlling a significant amount of the generation at a given time in a given region. An analogy might be one in which there were not several automobile manufacturers but one or two big ones; the incentive to compete, innovate and cut costs and prices with attentiveness to customer service might not exist in such a situation.

The second type of market power is vertical market power, in which one or a small number of companies own and control not only generation, but also the means of delivering the power to customers over wires. This refers to the vertically-integrated utilities. The concern arises when the company that owns the means of delivering power refuses to sell (or offers to sell at an unreasonably high price or with unreasonably onerous conditions) the access to the power grid, often in the interest of preserving a market for its own, possibly more expensive, power.

States do not have the ability to control all the elements of market power; they share that jurisdiction with the Federal Energy Regulatory Commission (FERC). However states do have a great deal of influence over market power, and have exercised that influence in a number of ways.

Corporate and functional separation

Many states encouraged or required functional separation of the generation side of the business from the wires side of the business. Montana, for instance, stated in S.B. 390 (1996) that the utility shall functionally separate electricity supply from retail transmission and distribution. Utilities were required to prevent undue discrimination in favor of their own power supply and prevent any form of self-dealing that could result in noncompetitive electricity prices. Utilities were further required to grant customers and suppliers access to the utilities' retail transmission and distribution systems on a nondiscriminatory, comparable basis.

New Hampshire, in H.B. 1392 (1996) required "at least functional separation of generation from transmission and distribution services." New Hampshire went on to state that such functional separation should not preclude utilities from continuing to own small-scale distributed generation equipment. Other states elected to preclude all generation ownership by distribution companies.

Utilities complied with functional separation orders by creating affiliate organizations for the different functions. They also adopted codes of conduct, approved by the state, for employees and the companies to prevent inappropriate communication that might be unfair to competitors. Often, employees were moved so that affiliates did not share floors in the corporate headquarters. And they also adopted transaction rules, also approved by the state, to prevent sweetheart deals between affiliates. With these safeguards, policymakers expect functional separation to sufficiently protect consumers while not unduly disrupting the economy of scope present in a utility.

Divestiture requirements and encouragement

Many states felt that a clean way to address market power would be to require utilities to sell their generating assets. But although many utilities did end up selling significant portions of their generating assets, and in a small number of cases the wires as well, most states allowed utilities to divest, but did not require divestiture. In general, state legislation viewed the decision to divest as a business decision and not appropriate for legislative requirement.

The one exception to this rule was Maine, which required the utilities to divest all generation assets and generation-related business activities. California is often cited as a state that required divestiture through legislation, however there was no divestiture requirement either in legislation or in regulation. Utilities in California were given an incentive of a higher return on their remaining assets to divest a significant percentage of their power plants.

Demand Response

A lesson from the incidence of wholesale electric price spikes in the last few years is that a price-driven real-time response by customers to reduce demand can dampen or eliminate the ability for suppliers to bid up prices. When a sufficient amount of customer load is committed for interruption at given prices, the chances of spot market prices spiking beyond these prices are significantly reduced. All consumers benefit in this situation.

With the development of regional electricity markets, the key developments in this area are in the independent system operators (ISO) and regional transmission organizations (RTO).

States are fostering these developments by encouraging load serving entities to offer regional or state demand response programs to customers. States can also consider changes to tariffs that communicate the value of demand response to customers.[41]

States set up systems to address the credibility of market players as well as consumer protections

Many state policymakers expressed early concern that inviting new and unknown companies into the state to sell electricity could open the door to unscrupulous marketing practices, unreliable companies and loss of consumer protections. And indeed there have been such instances in other similar businesses such as telecommunications. Telecommunications companies have in some cases admitted to switching customers without their permission, a practice known as slamming, or added new services such as voice mail or call waiting to a customer's bill without the customer's permission, a practice known as cramming. Practices like slamming and cramming are not the norm in the electric industry, but many policymakers have felt it necessary to put in place specific protections against cramming, slamming or other such practices.

Most states set up a broader system that required retailers to obtain a license from the public utilities commission before they could operate in the state. In general, conditions of this license required the retailer to prove it had financial capability to do business in the state, and often had specific provisions against consumer abuses. Failure to abide by state laws meant losing the license. Some states used their licensing provisions to address a concern that came up late in the debate: state and local taxation of the power industry.

An example of consumer protections comes from Maine (H-568), which established a number of standards and requirements, mostly to be put in place by the utilities commission. Maine marketers were required to secure a license. But in order to secure a license, they needed to provide evidence of financial capability, show they could enter into binding interconnection agreements with transmission and distribution utilities, disclose all pending legal actions or consumer complaints from the previous 12 months, and disclose names of affiliates. As a condition of licensure, providers supplying power to small customers were not allowed to terminate service without at least 30 days notice and could not telemarket to a customer who has

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[41] Information on demand response program policy has been developed by the New England Demand Response Initiative, http://nedri.raabassociates.org/.

filed a written request not to receive calls. The PUC is able to revoke the license of an entity that violates the terms of its license and impose a $5,000 per day penalty for every day that violations of the terms of the license take place.

States have revised the way they regulate distribution companies

Amidst the changes to the wholesale and retail sectors of the electric industry, the distribution part was often neglected, even though anywhere from 30 to 50 percent of a typical customer's electric bill pays for distribution system costs. In the manner of creating generic names for these sectors, like "genco" for generating company and "Transco," for transmission company the "disco" (distribution company) was sometimes jokingly referred to as renamed "boringco" for apparent low risk and lack of new challenges. As restructuring has unfolded, it has become clear that the distribution brings on restructuring challenges of its own.

One challenge relates to planning for load growth. Typically, utility distribution planners have focused on "wires" oriented solutions: higher voltages, double circuits, capacitors or other electronics. Some innovative distribution companies also look at other solutions such as load reducing resources, including resources on the customer side of the meter. Specifically, these resources distributed throughout a system include small scale generation in a community, customer-owned generation, customer efficiency, and customer load interruption.

To make effective use of these distributed resources, the distribution company must assess its system to find circuits which are seeing steady load growth which will lead to a significant and expensive upgrade of facilities which are not otherwise obsolete. Economists term these locations "high marginal cost areas." The opportunity to defer or eliminate these upgrades with less expensive local resources is one that distribution companies and their regulators are increasingly aware of. In Massachusetts, National Grid Company is conducting a pilot to demonstrate the effectiveness of this planning approach near Boston.

Another challenge concerns differential reliability standards. A growing part of the American economy depends on information systems with extremely high reliability, whether it is to support instant processing of credit cards or to support highly sensitive manufacturing processes. In the ways reliability is measured, the average reliability in the U.S. is 99.9 percent. These high reliability customers are looking for a level of 99.9999 percent or even higher. While the difference may not seem like much, customers will go to significant lengths to add redundant power systems if the utility system provides insufficient reliability for super-critical applications, like manufacturing and financial transaction processing.

Some utilities are looking at creating "power quality parks" to address this customer need. These locations would concentrate special facilities to provide the high reliability levels. Customers would pay for this service, but the cost to the consumer might be less than it would otherwise be because of the scale of the project. Wisconsin is developing a power quality park in the Milwaukee area.

Environmental Implications of Distributed Generation

While generation located on the customer-side of the meter offers a valuable source of electricity to the grid, the nature of the generation has significant environmental implications. If the generation is from high-pollution-emitting engines, a new air quality problem could result. Environmental regulators are looking for ways to distinguish between sources that may hurt the air, and sources that are benign or may actually help air quality by offsetting more polluting sources.

One way to do this has been developed by The Regulatory Assistance Project. As a result of collaborative process including state officials, industry representatives and environmental advocates, RAP has proposed a Model Rule for Siting Distributed Generation. The model rule can be adapted by individual state air regulators, but it addresses the key issues. The rule is output based, and is technology neutral. It is based on realistic expectations of the capabilities of small-scale generation technologies today and in the future.

http://www.raponline.org/ProjDocs/DREmsRul/Collfile/ModelEmissionsRule.pdf

Regulators are also likely to look for ways to hold distribution companies more accountable for meeting reliability standards of performance. Vermont regulators put in place reliability standards for its largest companies. The companies in turn can use these standards for annual employee incentive programs.

The third challenge relates to the distribution company's role as default provider. While competition develops, the distribution company has the very important role of acquiring power to meet the needs of customers who choose not to choose. After competition is more fully underway, some states may choose to continue meaningful service for these static customers. Public policy can be furthered by the way the distribution company carries out this responsibility, in terms of how stable the price is, and whether other public interests are part of the mandate.

Dampening market volatility is important to customers, but it is also important to sources of debt capital for power plants and to many of the companies in the supply chain. Therefore, it is important to reliability. Approaching this responsibility as a portfolio manager would lead the distribution company to reduce risk while getting the best deal on power. Ways to do this include making commitments for varying terms with multiple suppliers. It also may encourage them to use the distributed resources mentioned earlier to control growth and the risks associated with finding new power supplies.

It is also important that mandates like the renewable portfolio standard apply to default service to avoid unfair treatment of competitors and an opportunity to bypass public purpose programs.

States set up new systems to address state and local tax issues

There were three major concerns related to taxation of the electric power industry, and a host of minor concerns, about the effect of retail restructuring on state and local taxes:

a. retail marketers based out of state, or out of a city boundary, might be able to avoid state and local taxes like income, gross receipts or sales tax because they could claim that they did not have "nexus" with the state or locality. Lack of nexus refers to insufficient contact between the taxpayer and the taxing jurisdiction.
b. Property tax revenues might decrease as a result of changes in ownership or devaluation of power plants. Many state laws tax utility and non-utility property differently, and many power plants were expected to decline in value if they could not compete effectively in the markets.
c. Tax systems that treated different types of utilities differently and non-utility power generators and marketers differently would have a distorting effect on competitive power markets. Public power, rural cooperatives, investor owned utilities are each taxed differently from one another, and non-utility companies are often taxed differently still. Placing these entities in competition with one another in a business in which small differences in price can make or break a deal, could mean that the company with the most favorable tax treatment would fare the best under competition.

State laws addressed these issues in some cases with a major reform of their state electricity tax system and in other cases through temporary mechanisms designed to at least ease the transition to lower revenues from utility property. As with most of the issues discussed in this section, the short treatment given to the topic here will only present examples of how states addressed state and local utility taxes.

Nexus concerns

The major concern over nexus was that marketers might refuse to pay taxes on their income, gross receipts or sales, and that their refusal to pay such taxes would be upheld in the courts on the basis that there was no nexus – i.e. that there was an insufficient connection between the seller and the state or locality. The common example that many observers cited was one in which a company such as Utility.com sold power over the internet; in such a situation, would the state have the ability to tax either the transaction or the receipts or income of Utility.com? With the slow development of retail power markets, most of these concerns have turned out to be of less concern than originally thought. However, if competitive retail utility markets do develop, as policymakers in many states still expect, these issues will be important. The fixes that some states set up were fairly simple, others were more complex.

At least two states, New Jersey and Pennsylvania required payment of state taxes as a condition of licensure in the state.

Iowa and Connecticut opted for a more complex approach, choosing instead to rely less on the taxes most likely to be affected by competition, and to rely more heavily on taxes from parts of the electricity business that would remain in-state monopolies. Since competition is almost exclusively about competition for power generation and energy (rather than competition over who delivers the energy over wires) both Iowa and Connecticut elected to reduce taxes on generation and to increase taxes on the transmission and distribution wires parts of the business. The transmission and distribution parts of the business remain monopolies. Placing additional taxes on monopolies has no effect on the competitiveness of these companies, at least compared to other in-state companies. (Taxes of any kind that place one state's taxes much higher than those of surrounding states can , however, place the high-tax state at a competitive disadvantage in the region). Taxes levied on the transmission and distribution components of the business are also not subject to concerns over nexus; there is no question of whether or not the wires are physically in the state.

Property taxes

Ohio and Massachusetts dealt with the complex issues surrounding property taxes. Ohio, until it passed its tax reforms, taxed utility-owned property at 88 percent of its true value and non-utility property at 25 percent of its true value. As a result, it would be possible to have a power plant worth 100 million dollars assessed a taxable value of 88 million dollars if it were utility-owned and 25 million dollars if it were owned by a non-utility power generator. The competitive disadvantage at which this places the utility is significant. Ohio's solution was to change all of its power generating property in a class in which property was classified at 25 percent of value.

Massachusetts, Connecticut and several other states had a similar property tax situation, exacerbated by the concern that certain large power generating plants might shut down in a competitive market. The fact that those generators paid more than three-quarters of the property tax dollars into their local tax jurisdictions raised the specter of bankrupt townships and school districts

These states' solution was to protect the towns over a period of ten years, gradually phasing in the new property tax payments, with either the utility or the citizens of the entire state making up the difference between the projected new and the old property tax assessments. This has meant that the early years of the transition might be relatively painless, but the later years would be more painful as tax payments shrunk.

These changes to tax law have had the effect of preparing states for a more competitive power market. Since retail power markets have been so slow to develop, these changes have yet to be put to the test.

IV. THE WHOLESALE POWER MARKETPLACE AND ITS CONNECTION TO RETAIL SERVICE

The U.S. Congress and the Federal Energy Regulatory Commission have worked for many years to make wholesale electric markets more competitive. These federal officials have come to see competition as the most effective way to make the wholesale markets more efficient and deliver more benefits to consumers.

This effort is important to state policymakers and it is both easy and dangerous to ignore the influence of wholesale markets on the progress of retail electric competition. In fact changes in each market have influenced the other in significant ways, for better and for worse. Uncertainty over regulation of either wholesale or retail markets in the midst of these changes creates danger for consumers and market participants alike. There is a tension between taking the time needed to accomplish an orderly transition, and surviving a protracted transition without painful and costly market failures.

The wholesale electricity market has always had two basic functions. One is to enhance the **reliability of the bulk power system** for consumers by enabling load serving entities that are unable to deliver due to outages of either generation or transmission facilities to reach back-up suppliers. The second is to enable **commerce** among generation owners, transmission owners and load serving entities (electricity retailers). Commerce occurs when wholesale buyers decide to purchase electricity on the open market because it is available cheaper than it would cost them to generate it from units they own or control through contracts. Such commerce reduces consumers' electric bills by an estimated $13 billion per year, according to one recent estimate.[42]

Reliability has always been a primary function because widespread bulk power outages are very costly and disruptive. However, in the transition to competitive markets, commerce has assumed increasing importance and there is significant tension between the two functions. Consumers benefit if the generation and transmission systems are driven hard enough to achieve high levels of productivity – but it is important not to drive them so hard that large scale system failures occur. In the last few years, FERC has fostered a new institutional entity, the independent regional-scale system operator, to integrate and manage the day-to-day operations of these systems so as to maintain reliability and facilitate high levels of electric commerce on a non-discriminatory basis insulated from narrow commercial concerns.[43]

A Brief History of Wholesale Electric Restructuring

1978 – PURPA – Non-utility generators granted access to the electric grid plus other rights
1992 – Energy Policy Act – Open access to transmission, market-based rates authorized
1996 – FERC Order 888 – Creates independent system operator, allows market-based rates
1999 – FERC Order 2000 – Signals drive toward larger markets
2003? – FERC Standard Market Design – Attempt to complete the transition to competitive and more consistent wholesale markets

[42] National Transmission Grid Study, U.S. DOE, May 2002, pg 19.
[43] See http://www.ferc.gov/Electric/RTO/post_rto.htm

This section is not a comprehensive study of the evolution of wholesale market. It is instead a discussion of the important outcomes and drivers of these outcomes particularly as they relate to retail electric competition. The important outcomes covered here include pricing, rules, the importance of the demand side, and the relationship to capital markets.

A. PRICING

With the decision to rely increasingly on markets, the federal government, through the FERC, focused on how to change the wholesale market's pricing structure in a way that would encourage efficiency in the wholesale markets. The theory behind this type of efficient pricing lies in the signals they send to producers and consumers. Efficient price signals will encourage the energy producers and consumers to use resources in a manner consistent with their real worth. Markets will encourage organizations that produce or transmit energy to use the most valuable resources, and the market will respond to price signals in order to add new capacity in places where it is most needed. Less valuable capacity will be less likely to be built, or if it already exists, it will be more likely to be retired. If it is easy to trade energy and to trade the rights to use the transmission system, and if pricing is efficient, resources will tend to be moved through the market towards their highest value purpose. Efficient pricing will discourage waste.

The following table lists some of the pricing-related changes regulators and the industry are wrestling with today.

Comparison Table: Wholesale Market Pricing – Before and After Restructuring

At the start:	Where markets are headed:
• Wholesale prices for bulk power: cost-based	• wholesale transaction prices: market-basis reflects congestion (locational marginal prices)
• spot market: exists in some places to balance excess and deficient generation	• spot market: transparent trading day ahead and multiple settlements day of delivery
• markets for power and energy	• markets for power, energy and ancillary services (reserves +)
• service area transmission: one rate regardless of mileage (postage stamp) • regional transmission: each service area charges for contract path (pancake rates)	• regional transmission: single rate structure for broad market region
• retail customers: no contact w/ wholesale prices, no way to react to price changes	• retail customers: ability to see and react to wholesale price changes
• transmission tariffs: pay for transmission and generation run reliability	• transmission tariffs: pay for transmission, generation run for reliability, generation and customer-side investments for reliability
• compensation transactions based on contract paths for power sometimes did not reflect real flow pattern and did not compensate all affected transmission owners fairly.	• compensation: market areas growing to encompass all power flows, assuring fair compensation

What Is Efficiency?

Economists use the word "efficiency" to summarize a big idea. Economic efficiency means that society's resources and assets are used for their most valuable purposes. This means that decisions to deploy capital, to allocate investment among a range of resources, to consume energy – all these activities reflect society's values, positive and negative. Information is both accurate and readily available, and there are no constraints to efficient decision-making.

Pure efficiency is a paradigm, and as a goal for many policymakers and regulators. It may not be realistic to expect pure competition, but, as a goal, economic efficiency has been a powerful motivating force in electric industry restructuring.

Risk Management

Risk management has become a much more important aspect of participating in the wholesale market. The most obvious practitioners of this are electric generation companies. These firms have neither an obligation to serve customers, nor an assured market for their products. They are merchants. Their prices will not necessarily rise if their costs rise – but will instead be driven by the larger market.

Merchant generators must choose the proportion of long-term contracts they seek with load serving entities (distribution companies, like utilities or other electricity retailers that sell power directly to retail customers), compared with leaving potential power output uncommitted in hopes of taking advantage of high spot market prices. In this way, some merchant generators who sold vast amounts of power through the spot markets when electricity prices spiked in 2000-2001 made a great deal of money. The generators who had already committed to sell their power through long-term contracts to load serving entities made less money.

Spot market prices have continued to be volatile, failing sharply in 2002 and increasing somewhat in 2003. Continued volatility illustrates the benefits of a mix of shorter and longer term commitments.

Less obvious examples of entrepreneurship and new ways to manage risk and energy portfolios have developed in response to competitive wholesale markets. There have always been energy traders, but their trades mostly took advantage of different energy portfolios among nearby utilities: trading peaking capacity for base load, for example. California utilities routinely sold power to utilities in the Pacific Northwest during the winter time, and received power from the Pacific Northwest in summer, when it was needed most in California. The market backdrop was not nearly so volatile, nor was risk management as intense a motivation as it has become.

Now, with increased volatility in energy markets and more intense interest in risk management, both to manage risk and seek large profit opportunities, energy trading has emerged as a major force. In some situations, this intensity has led to abusive behavior by traders who have stretched or violated market rules in search of sales growth and profits.

Wholesale Market Changes Causes Rethinking of Industry Communication and Cooperation

The history of the electric power industry is dominated by joint actions by electric companies. Building and operating the transmission grid, growing the nuclear power industry, coordinating research and development – these activities and more were characterized by close cooperation among electric companies.

In most other industries, this behavior would be unthinkable because it would be anti-competitive collusion. But these companies were not competitors. Each had a monopoly in a discrete geographic area.

Companies now face an increasingly competitive wholesale market, whether they have restructured or not. This has strained the ability for previously collegial companies to work cooperatively for public purposes like reliability and unbiased markets.

One example of this occurred at the North American Electric Reliability Council, (NERC). NERC was created with a "stakeholder" board of directors – over 30 utility executives overseeing an organization designed to keep their systems and those of their colleagues reliable. With new markets in place, the industry and its regulators realized that the business interests of the directors could get in the way of NERC's reliability mission. As a result, the stakeholder board was replaced by a new board made up of non-stakeholders.

B. RULES

At the onset of the debate about restructuring, the wholesale market was characterized by monopoly companies operating the grid to assure reliability. Companies had an interest in assuring that their transmission and generation facilities maintained their value. But incentives for vibrant commerce in wholesale markets were incidental. The North American Electric Reliability Council presents a good illustration.[44] NERC was formed after the blackout in the northeastern United States and eastern Canada in 1965. Until recently, it was run by a board made up of the major utilities. Its rules and reliability standards were enforced without any regulatory backstop. All utilities recognized the importance of compliance, the standards were effective and fair, and so the utilities complied with the organization's rules.

With a competitive wholesale market and rates based on the market instead of regulation, the entire basis of industry co-operation changed. Decisions about what power plants or power lines were used, and when they were used could now have enormous financial implications for individual firms. As a result, FERC has been attempting to set up rules that will govern: reliability, markets, interconnection and market power. These rules will ultimately affect where a company operates, what its assets are and with whom it has long-term contracts. They will make winners and losers. Well-designed rules also should ensure that competition favors the public interest.

[44] http://www.nerc.com

Are Low-Cost States in Jeopardy?

Electric rates vary throughout the contiguous United States. While the national average electric rate is between 6.5 and 7.0 cents per kWh, some states have average prices of less than 4 cents. Others are above 11 cents. These differences are driven in large measure by differences in the availability of low-cost natural resources suitable for the generation of electricity.

Higher cost states, such as the Northeast and California, have looked at wholesale market restructuring as an opportunity to improve their access to lower cost power from other regions.

Lower cost states, such as those in the Pacific Northwest, are concerned that the power that presently serves their consumers is in limited supply and could be siphoned away, raising their prices. This concern is based on the fear that current “native load” entitlements to the power (meaning the entitlements of the retail customers in those particular geographic areas who have long received that power) will not last forever, and that profits from the sale of the power will be diverted before they can be credited to consumers through the ratemaking process. If power supply is divested from the local distribution company, the regulatory link between generation and consumer is broken. In this event, the distribution company in lower cost states will have to compete against the high cost states for power, and prices are likely to be higher.

If, however, native load customers retain utilities with generation ownership, there is a chance that regulation can preserve some or all low cost power for the customers that historically used it, even with wholesale market reforms. Long-term commitments of this power to “native load” customers would prevent it from serving others in the regional electricity market.

Reliability

One set of rules for public policy relates to reliability. A traditional goal for reliability planners has been to ensure that the electric system has a probability of failing less than one day in ten years.[45]

Reliability does not happen without planning. Planning for the possibility of a problem means the power industry must invest in facilities that it might only use in rare, stressful circumstances. Sometimes, power systems must rely on more expensive resources simply to meet reliability rules, while less expensive but poorly positioned resources remain idle. Someone has to pay for these more expensive facilities, and allocating costs and responsibilities is a significant part of FERC-supervised market rules implemented under FERC tariffs. Policies must also determine who manages and enforces these rules.

[45] Referring to reliability of the transmission system, where many companies are involved and a problem can affect millions. Reliability of the distribution system is a distinct subject.

Electricity as a Commodity: The Problem of Storage

A fundamental in the transition to competitive wholesale markets is that electricity can have the attributes of a commodity. A commodity can be traded most effectively in a market where buyers and sellers can easily reach each other, and trade prices are public. Such a market is often described as liquid and transparent.

Typical of many commodity markets (grains or petroleum, for example) is that the product can be stored relatively easily. But electric power has only limited storage capacity, at least at present. This means that wholesale markets must produce and deliver nearly exactly the amount of energy customers are demanding at any given time. The cost of this flexibility in terms of redundant and reserve capacity can be significant, especially because of modern expectations of nearly perfect reliability.[46] Prices can be volatile if there is little excess capacity. Shortages are not tolerated except in very extreme circumstances. Bringing down the cost of reliability is one of the objectives of wholesale market improvements.

Markets

The daily conduct of markets is based on a dizzying array of rules. When are generator offers for the next day due? When must they be accepted by load servers? Can they be changed during the day? What products will be traded in markets? Will rules in neighboring markets be compatible?

The objective of market rules is to assure that, consistent with reliability standards, market participants have the opportunity to trade with anyone else in the market and to strike prices that are available to everyone. Effective markets need to be "transparent," implying that nothing about pricing or the availability of products is hidden.[47] Decisions among the players may be different because of their objectives, their resources and their needs, but the opportunities to trade should be the same. Rules must also serve to prevent suppliers from gaining excessive influence over prices.

A result of these changes in pricing and market rules is a geometric increase in the number of energy trades.[48] Generally, these trades move power to areas where it is more valuable, economically benefiting both suppliers and consumers. The task of the system operator to monitor the effects on reliability and prices is significant and it is still uncertain how system operators, FERC and the states will secure this function. At times, market players or the organizations that oversee the markets have been forced to stop trades because they ran up against

[46] The transmission/wholesale system delivers power at a reliability rate of between 99.90 percent (three 9s) and 99.99 percent (four 9s).
[47] While information may be perfect in a market, there may still be a barrier to entry. The amount of effort required to master and use the information in a competitive way may be more than some participants are willing to maintain.
[48] The scandals associated with energy trading that emerged in 2002 have revealed that some of these were phantom trades designed to pump up trading volumes without any benefit. Other trades represent risk management strategies which may not actually lead to changes in power flows. Even with permitted trades only, the number of trades and increases in trade volume are not sufficient to conclude anything about the need for more transmission facilities.

physical or other reliability-based limitations. The number of such instances has increased significantly from 1999 to 2002.[49]

FERC Order 2000 and the Regional Transmission Organization

The current "last word" on wholesale markets is the so-called Order 2000, issued by FERC in late 1999. Order 2000 includes seven specific functions of regional transmission organizations, or RTOs. They are:

- Tariff design and administration
- Congestion management
- Ancillary services
- Calculation and reporting of available transmission capacity
- Market monitoring
- Planning and expansion
- Interregional coordination

Interconnection

The process of hooking new power generation into the existing grid is called interconnection. Historically, interconnection rules dealt strictly with the reliability effects of the new generation. The grid's operators would ask if the new power plant will operate with the existing transmission system, or whether some transmission upgrade was required to maintain reliability standards.

In the developing competitive market, denying or impeding interconnection can create a barrier to entry for new generation and brokers of that product. It is increasingly important to create a market-neutral system operator that will manage the process of interconnection fairly and ensure that all new comers are treated fairly.

The effects of connecting large generators to the grid are likely to be greater than those for smaller generators. FERC has recognized this and has indicated that it may adopt a different set of rules for interconnecting small generators that are less than 20 MW.[50]

[49] Data on transmission limit reports may be skewed by inappropriate trading practices. Recent scandals involving energy trading firms indicate that volumes of trades were inflated in various ways in an effort to deceive investors. These data should be approached with caution. The authors agree, however, that trading volumes have risen in response to FERC's liberalization of wholesale markets.
[50] A notice of proposed rulemaking is open at the FERC (at this writing) on the subject of small generator interconnection. FERC Docket RM02-12-000. An issue hovering above the details is jurisdiction. Some state advocates assert that interconnection of generators to the distribution system is a state matter. Others argue that because the power ends up affecting wholesale markets, federal jurisdiction applies.

Market Power

Market power refers to the ability of market participants, usually sellers as opposed to buyers, to affect prices deliberately through any number of means. Market power interferes with the ability of consumers to influence prices through their buying choices. Absent market power, if consumers want more electricity, they will bid the price up, and if they demand little electricity, then prices will fall. However electricity is a distinct market in several ways. Nearly all people need it. Most customers are not experienced in buying it or managing their use of it in real time.

It is possible for generators to accumulate the power to set prices in a few ways. If generation ownership is concentrated in too few hands, it may be easy to accumulate market power. Illegal, collusive communications are not necessary for a small number of generators to behave anti-competitively. Opportunities to exercise market power are more likely if generation and transmission infrastructure is in tight supply.

Environmental Implications of Market Rules

Just as wholesale rules have financial implications, they also affect the environment. Environmental advocates have suggested that the environmental consequences of generation should be factored into the way it is dispatched. The industry has suggested that it is up to public policymakers to give specific directions along these lines.

Policymakers have responded by creating cap and trade systems for the emissions of some pollutants, adding some cost to affected generators. Some states have added renewable portfolio standards that create a niche in the market for preferred generation types, regardless of their cost, though hopefully using competitive forces to minimize the cost of this subset. These are in addition to controls prescribed for particular generators.

Further reliability rules require that some amount of generation (usually an amount at least equivalent to the size of the largest power source in the area that could fail, a “first contingency”) be available within zero to ten minutes. The generators assigned this role are usually the least efficient, and often least clean, of the units available. They might be quick start diesel engines. Unless new, these machines generally have high emissions of NO_x, particulates and other harmful substances. These emergency generators are usually permitted to run for a few hours at a time, and just a few hundred hours each year. They also might be boilers that are kept “hot” but at a minimum load, ready to ramp up to full load as quickly as needed.

Rules that reduce the need for these peaking resources to run can have a significant, positive effect on air quality.

Coal-fired generation from coal-intensive regions is able to sell power in a larger footprint with more fluid markets. Some increased emissions of criteria pollutants results from this trend. While SO_x is capped nationally by the Clean Air Act, regulation of other pollutants is still the focus of developing regulations. Control of CO_2 and concerns about climate change are also unresolved. When these issues are settled, there may be a significant effect on power plant emissions beyond what market rules have produced.

Merger and acquisition policy at the FERC is important to identifying and preventing the potential for collusive behavior. Scarcity, as was demonstrated in the California power markets in 2000-2001, presents an opportunity for those generators that are not already committed to contracts to increase prices. This illustration of market power is one in which suppliers take advantage of the legal requirement for load serving entities, distribution companies and the system operator to keep the lights on.

A more insidious source of market power can occur when the generator withholds generation from the market in order to create a scarcity situation, intending to release the withheld power at the moment when it can fetch the highest prices. While there is significant risk of lost revenue in this strategy, the potential to profit is enormous.

It is important, however, for the system operator to be able to evaluate these situations as they happen, so that the operator can identify and mitigate it promptly. This capacity to monitor the market is an essential element to assure all market participants, from generators to load serving entities to customers, and regulators that the market is functioning in the public interest as it should.

Planning in Regional Wholesale Markets

While the jurisdictional lines of electric regulation divide authority between state and federal, the reality is that wholesale markets are regional. In sketching the role for the system operator, FERC specifies planning and resource selection as a vital function to making markets work for consumers. How might this work?

One response has come from a National Governors' Association Task Force on Electric Infrastructure. The NGA task force suggests in a 2002 report that states join together through memoranda of understanding to form multi-state planning organizations to work in concert with the system operator. These multi-state entities (MSE) would mirror market areas in size and would apply a public interest perspective on the planning work of the system operator. It would also consider prospective needs on the transmission system, providing siting proceedings in individual states a public interest perspective on the regional need of proposed facilities.

Another response is represented by the 2001 publication from the National Association of Regulatory Utility Commissioners (NARUC) "Efficient Reliability." Efficient Reliability notes that transmission grid needs can be addressed by more than just transmission solutions, that generation and resources distributed through the distribution system, including on the customer side of the meter, can also benefit the system, and may be superior to transmission alternatives. The report posits the Efficient Reliability Standard, which articulates how all prospective solutions should be considered for these monopoly investments in reliability.

Important to the success of any new regional grid planning effort is the ability of the plan to produce action of capital investors in transmission, generation and demand side resources to meet the needs that the plan highlights.

When power prices go up, it is not necessarily because market power is present.[51] In fact, high prices can be an indication that the market is working as it should by sending a price signal that indicates scarcity. Scarcity may lead to situations where significant extra costs (overtime, contractors, other maintenance costs) are incurred to bring generators on-line, or to keep them running. When generation has to be transmitted a significant distance, additional costs may be involved.

C. THE IMPORTANCE OF THE DEMAND SIDE

In the system of the vertically integrated utility, the connection between customer demand and generation supply was internalized within the utility. The cost-based system created no particular need for customers to value their consumption and to offer to reduce consumption for a price. Some large customers did sign contracts with utilities that exchanged a lower power price for the utilities' right to temporarily shut down electric service to these customers. Known as interruptible contracts, these contracts are a relatively unrefined instrument for manipulating the relationship between retail demand for power and the wholesale market.[52]

The Last Inch – The Federal-State Jurisdictional Interface

Optimally, the roles of state and federal utility regulators complement each other, covering all activities without overlap. For some, the difference is described this way: all retail activities are covered by the states, federal regulators cover everything else. Regulators have set up their organizations with this dichotomy in mind.

Others point out, however, that with retail competition, larger customers are taking service from the high voltage transmission system, rather than the lower voltage distribution system. Since the transmission system is inter-state in nature, and federal regulation fundamentally addresses inter-state commerce, retail relationships that use only transmission are not under state jurisdiction.

Because there is value in maintaining a wholesale-retail split in responsibility, some have endeavored to create a new way to justify the traditional division. One way, offered by William Massey, a FERC commissioner, creates the notion of "the last inch." Massey claims federal jurisdiction for all transmission facilities and commerce on those facilities. But he suggests reserving for the states jurisdiction over the point where the relationship becomes retail.

Demand response programs merge retail and wholesale aspects, and ambiguity on jurisdiction could interfere with deployment of useful programs. It is unclear whether inevitable legal interpretations of this and other potential solutions will resolve this matter for good, or if uncertainty on this point will persist.

[51] Joskow, Paul, Edward Kahn, *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000*, 2000.
[52] Many of these contracts were effectively ways to provide discounts to customers – both sides never expected the interruptions to occur. The California rolling blackouts of 2000 dispelled this notion.

With the new market structure in which generators operate independently from load serving entities and from transmission companies, the relationships and underlying motivations change. The demand side of the market – customers – represents a key element to maintaining discipline in the market.

In real time, as prices for generation rise from, say $100 per MWh toward $500 or $1000 per MWh, some customers may find that they would be happy to accept, say, $250 per MWh to temporarily curtail or reduce their use of electricity. This arrangement not only makes that participating customer happy, but it dampens the price rise affecting all the other customers in the market.[53] Price responsive demand response programs represent a key element in a competitive wholesale market.

In the long run, customer resources like distributed generation and efficiency will serve to slow the demand for new generation and to moderate cyclical price volatility due to construction booms and busts. Unfortunately, the way reliability-oriented resources are designed and procured at present does not tend to address demand side resources and their potential to address system needs in a manner similar to transmission and large-scale generation.[54] In fact, incentives for distribution companies and load serving entities to promote sales tend to keep demand resources from the market.

Corporate Structures

Mergers of electric companies happened before restructuring, but with new ways to think about increasing earnings per share, creativity to remake corporations was energized.

Motivations for corporate restructuring included: gaining earnings in new businesses; using the strength of the utility balance sheet to finance the new enterprises, some electric related, some not; gaining economies of scope and scale, creating larger service areas, and/or adding gas to the prevailing electric service; providing outsourcing services to other utilities in areas of expertise; separating parts of the existing regulatory business to allow creation of unregulated affiliates with greater earning potential; and diversification into other regions or other countries. Sometimes, the state required the utility to divest some part of its operation in the interest of assuring that it could not impose its will on prices or drive competitors out through unfair use of its assets.

Concerns government expressed about these mergers and restructurings included: the loss of local influence over utility decisions; a loss of focus on the utility business while chasing an affiliate's higher earning; a declining number of potential competitors in a region and the effect on working markets; the division of merger savings between consumers and shareholders and the course of future electric rates; job security of merged company workers; and added risk to the core business from mergers with unregulated businesses.

Mergers are often approved, but they have provided an opportunity for regulators to attach conditions to achieve policy objectives that might be difficult or impossible to achieve any other way.

[53] S. Braithwait and M. O'Sheasy, "Customer Response to Market Prices -- How Much Can You Get When You Need It Most?" EPRI International Energy Pricing Conference 2000, Washington, DC, July 2000.
[54] Cowart, Richard, et al, Efficient Reliabilty: The Critical Role of Demand-Side Resources, NARUC, 2001. See also http://nedri.raabassociates.org/ for a comprehensive set of reports and recommendations on the subject of demand resources developed by the New England Demand Response Initiative.

FERC's Standard Market Design Notice of Proposed Rulemaking

A consistent message in FERC orders over the past decade is its desire to benefit consumers by improving the efficiency of wholesale electricity markets. The most recent expression of FERC's vision for how to make progress in this area is its 640 page notice of proposed rulemaking on Standard Market Design.

FERC's stated objective is to remedy undue discrimination in inter-state transmission service, and to assure just and reasonable rates within and among regional power markets. FERC's purpose is to break down "seams," the web of incompatible rules that restrict or prevent productive trade within and between regional power markets, and to improve a system that they view as increasingly important in the context of electric industry restructuring. FERC also expects to combat market power, when and where necessary.

FERC's vision is to ensure that any physically feasible and economically productive transaction consistent with reliability is not blocked by market rules.

FERC renames the system operator, the Independent Transmission Provider, which is to administer energy markets, long-term planning, system studies, and calculations of available transmission capacity. FERC also proposes to require a regional planning process that includes state government participation.

FERC envisions bid-based markets for energy and other elements of electric service, and these markets would see prices that reflect system congestion costs. Bid caps would be established to control price spikes.

FERC addresses capacity adequacy concerns by creating a three-year resource adequacy requirement for load serving entities, and it invites the states into the decision-making process on what the requirement should be.

Addressing concerns of low-energy-cost states that worry their costs will rise toward a regional average, FERC asserts that sufficient low cost power is under long-term contract to local distributors and that these states have nothing to fear.

The proposed rule also addresses market power, and is designed to avert market power by ensuring the long-term adequacy of generation and the transmission infrastructure. It also recognizes the potential of customer resources to benefit the transmission system, and expects them to be considered in the prescribed regional planning process, and compensated in a manner that does not bias investment choices between large and small scale resources.

FERC has also recognized the issue of how to allocate costs for system improvements: i.e. whether they should they be spread over a broad region, or, when their cause can be identified, be assigned to the region causing the costs. While FERC has indicated a preference for "cost causation," which could trigger a major change from the industry's traditional practice of spreading such costs widely.

Many voices have been raised in concern or opposition to FERC's efforts. Some are concerned that the market FERC envisions is not realistic, and consumers will lose important protections in the process. Others are concerned about the reduction in regulatory control by states over transmission and low-cost generation resources in their states.

The scope and gravity of this topic have led FERC to extend its schedule. If the Standard Market Design rulemaking process results in a final rule, the rule could be issued some time in the latter half of 2003.

D. THE EFFECT ON CAPITAL FLOW TO THE ELECTRIC INDUSTRY

Capital markets seem a long way from retail electric customers. Yet a reasonable flow of capital to support transmission and generation investment is critical to assure reliable electric service. In some states, regulated companies are barred from building new generation. What can affect capital flow?

As this paper is being written, the electric industry is experiencing the answer to this question in the form of capital constraints for new generation. The most obvious part of the answer is uncertainty, in this case, regarding how electricity businesses will earn revenue to meet their financial obligations to lenders and the financial expectations of shareholders. Regarding generation, bondholders seem to be asking for more long-term contracts and less reliance on spot markets and trading. Whether there will be a separate market for generating capacity as opposed to energy is an important pending question.

The transition to markets is not complete. Sweeping changes proposed by FERC and market participants are pending. Behavior that generators may think is necessary to meet financial expectations (bid strategies causing high market prices, for example) may in fact be forbidden as an abuse of market power. If business models are too uncertain, the nine or ten figure projects on the drawing boards will stay there.

Other risk factors affect capital access. Utilities' failed forays into unfamiliar businesses dampen enthusiasm for diversification. Meanwhile, businesses that have focused on monopoly-oriented wires businesses have easier access to capital.

A growing concern is the risk associated with the parties with whom the market participant does business. If key customers or suppliers have a thin capital structure or rely on other companies that do, the cascading effect of instability will rest uncomfortably at the door of bond issuers and shareholders, who will require higher rates of return for the use of their money.

The rating agencies, Standard & Poor's, Moody's and Fitch, have always been important. In the early days of restructuring, they had difficulty evaluating some of the newer ideas from electric companies, notably concerning the value of energy trading. Their role today – to discipline the investment strategies and business models of wholesale market participants - is pivotal to the cost that consumers ultimately pay for electric service, and the reliability of that service. Regulators and policymakers can help by being sensitive to the messages of the rating agencies and considering these messages in their deliberations.

Looking forward, issues to be addressed include: the degree to which market rules will be standardized across the country and how standard the "system operator" function and structure will be; how will planning for grid needs be conducted, recognizing that the alternatives come from both competitive and monopoly providers.

The next and final section of this report brings together lessons from restructuring in both the retail and wholesale markets and offers policy options for government officials to consider.

V. POLICY OPTIONS

This report has reviewed the state of the electric industry and the attempts of regulators, legislators and the industry itself to restructure the industry. States have tried many different policies and many are now revisiting and refining those policies. This section offers insight on options that policymakers may consider as mid-course refinements and corrections.

This report reveals a selection of state policy options divided into five primary courses.

1. Encourage choice. Redesign the system to either offer financial incentives to people who switch or raise the prices for people who do not switch such that they see economic value in switching.
2. Go slow. Recognize that, at least for a while, small customers are not likely to switch. Attempt to find policy approaches tailored to the needs of small customers that bring the benefits of competition but leave in place the protections of regulation. These approaches might best be classified as hybrids of regulation and competition and retain significant monopoly structure. Apply lessons learned from state restructuring efforts even if the state prohibits retail competition.
3. Go back. Decide that a truly competitive market is not achievable, at least in the near term, so reverse plans for retail competition and restore the vertically integrated utility.
4. Government steps in. Step back entirely from the idea of a competitive retail market and, instead, explore ways for the government to be directly involved in the procurement and sale of electricity.
5. Transmission and public interest policies. Some practices and policies offer consumer benefits independent of the state of competition, or the way the industry is organized. Monopoly states may also consider these. These relate to transmission, planning and public benefits.

The report lays out a range of policies that includes several designed to encourage consumers to choose and marketers to market to small consumers, several that explore new means to bring benefits of choice to large groups of small consumers, and some that examine new institutions for delivering power to small consumers. The report is inclusive of policies rather than exclusive, and provides a brief description and analysis of each.

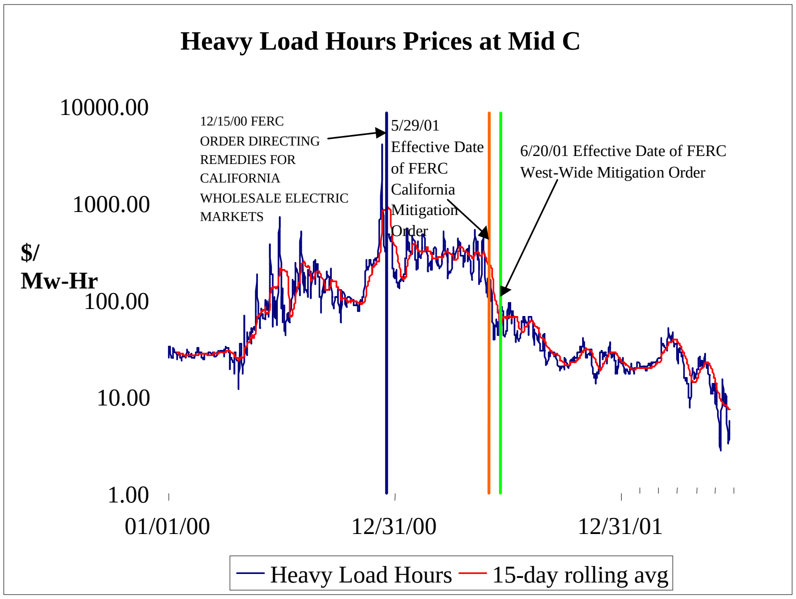
A. PRICES ARE DOWN; WHY CONSIDER NEW POLICY NOW?

Uncertainties Remain

The years of 2000 and 2001 were traumatic for the electricity industry, particularly in the western states, which experienced near-and real blackouts, job losses, high electricity prices and economic disruptions on a scale that most people would have thought impossible at the close of the 1990s. Since then, the power markets have become somewhat calmer, though fundamental causes of 2000-01 events remain. As figure 12 demonstrates, electricity prices have settled at levels that have not been seen since 1997 and 1998. Lower prices have contributed to a credit crunch affecting the entire electricity industry. Natural gas prices have fallen, though they have subsequently crept up again. It appears that the threat of imminent blackouts has subsided. The crisis and its atmosphere that pervaded during 2000-2001 have receded, leading some observers to wonder what happened to the urgency, and what will happen next.

This atmosphere of calm offers an opportunity to assess state electricity policies in the context of the lessons of 2000 and 2001. The current atmosphere of calm also masks risks evident in the power system. Some of the high and volatile power prices that came about in 2000-2001 may recur. The risks may not manifest themselves immediately, but instead may be seen on a horizon of a few years.

Figure 12: Spot market prices in the Pacific Northwest, 2000-2001



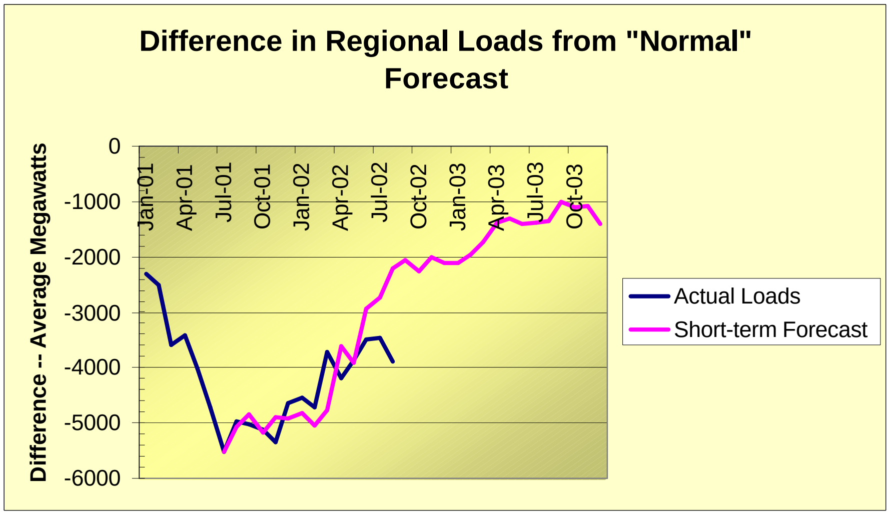
Source: Northwest Power Planning Council, 2002.

The power market difficulties since restructuring began resulted from six major factors:

- High natural gas prices;
- A drought in the west;
- Lack of sufficient generating resources to supply a growing economy coupled with insufficient attention to energy efficiency;
- An inadequate transmission system;
- An immature wholesale power market subject to manipulation and only weakly able to contend with normal price and supply volatility; and
- An almost non existent connection between retail consumption and wholesale electricity markets with no way for most customers to affect the wholesale market.

Since 2001, the economy has slowed and the demand growth for power has stalled or even fallen as a result. There has been a response by customers most affected by high prices to use less energy, though the bulk of this response may be temporary. The chart below shows that the demand for power currently is significantly below expected levels in much of the West.

Figure 13: Difference in Regional Loads from "Normal Forecast"



Source: Northwest Power Planning Council

Natural gas prices have fallen again, and power generators stimulated by high electricity prices that existed during the period, brought approximately 15,000 megawatts of new generation on-line in the West with approximately 5,000 more under construction. As a result, the near-term forecasts for 2002 through 2004 or 2005 show a system that is better balanced and unlikely to experience major problems.[55] Other regions report a similar status.

Yet, the energy business of late 2002 is beginning to bear similarities to that of the late 1990s, prior to the crisis atmosphere of 2000. As wholesale electricity prices have fallen again, the incentive to invest in new generation has diminished. The capital markets now look askance at most new investments in power generation, partly as a result of the Enron bankruptcy. Of the many thousands of megawatts of new generation announced in 2000 and 2001, many were delayed or cancelled in 2002. Figure 14 illustrates this trend.

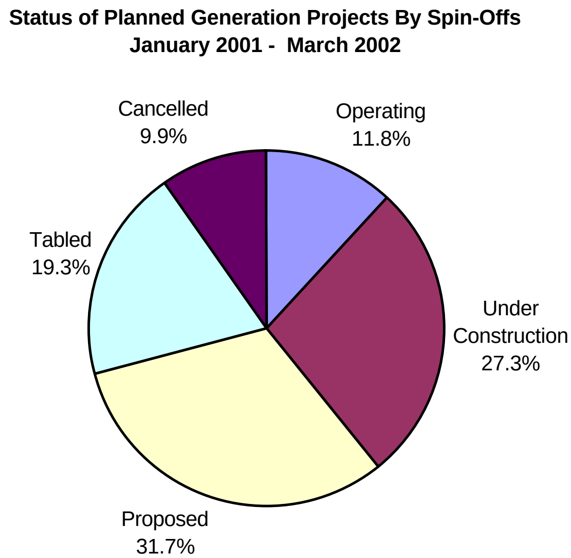
Natural gas prices have hovered near the levels that they exhibited prior to the 2000-2001 crises. Although these prices have translated into lower power prices in an industry that is increasingly reliant on gas as a feedstock, it also has meant that the number of new gas wells has again declined. Because more than 90 percent of new power plants use natural gas, this bodes poorly for the future of low, stable gas prices.

Finally, although the economy is now soft, it will eventually recover, and economic recovery will increase demand for power.

Against this background, the movement to retail electric competition has stalled. Numbers of customers switching has peaked. States not already committed to retail competition are placing themselves in a holding pattern.

[55] Source: Northwest Power Planning Council, 2002.

Figure 14. New Generation Planned or Cancelled



Source: Edison Electric Institute

With states increasingly relying on markets to allocate capital, and limited capacity for regional planning in many states, government is under-equipped to address the concerns recited in the immediately prior paragraphs and prepare counter-measures for policymakers.

<u>Some States Are Facing Decisions</u>

Some states also face a deadline. These states established a transition period and the prices for customers who did not choose an alternative provider were either capped or frozen. The end of the transition period marks the end of these rate caps or freezes in many places. Yet most state lawmakers contemplated that the end of the transition period would also mark the time when markets would be competitive and numerous marketers would be selling directly to most retail customers. That competition has not occurred yet, at least not for smaller customers, so policymakers face a choice: stay the course and end the transition period and the rate freezes as planned, hoping that small customers start to see some true choice of product, or follow some other course.

Policymakers may find that several questions confront them as they try to decide what to do:

- Is electricity policy in the states sufficiently prepared should new crises appear, even ones of a smaller magnitude than those of 2000 and 2001?
- What changes have been put in place to insulate states and electricity users from the effects of such a crisis, should one again occur?
- Is volatility a necessary part of efficient electricity markets that will promote the long-term best interest of consumers?
- Are there policy solutions that are desirable in all circumstances, and others that are only appropriate in certain regions or situations, driven by issues like population density, economic activity, geographic relationship between load and generation, localized fuel

issues (access to gas, dependence on hydro, air issues), transmission constraints, asset ownership structures, rate disparities or regional cohesiveness?
- As electric use continues to increase, will infrastructure be there to serve increasing demand, and can the current rate of growth in electric use be reduced with no harm to the economy?

B. POLICY OPTIONS

The policy options described below are grouped into five major categories. These options are meant to illustrate the full range of policy options available to policymakers and to stimulate discussion on the range of policies.

- Encourage choice
- Go slow
- Go back
- Government steps in
- Transmission and public interest policies

A Question of Basic Policy

Policymakers face an important, fundamental question regarding goals:

1) Should the state encourage competition for small consumers because of its potential long-term benefits? Competition implies that consumers face both upside and downside risks and that those risks encourage them to make choices. A policy to encourage competition implies rates for the smallest, default customers that are not the lowest possible, but instead are "safety net" rates. "Safety net" rates are not the lowest possible rates, but they are high enough to encourage customers to switch to an alternative provider.

Or

2) Should the state shield default supply consumers from risks through mechanisms like price caps and low standard offer prices, or by limiting competition to large customers only? Shielding consumers from risks and keeping prices low will remove the motivation for consumers to participate in competitive markets, but such a policy of explicit consumer protection is attractive, as well.

Encourage Choice

The first set of policy options explores several means to stimulate the market for the smaller customers. It is based on the following three assumptions:

- *Some change to the existing system is warranted.*

- *Competition is achievable for all customer classes. However, to overcome economic barriers of high marketing costs and relatively low savings for small customers, some incentives are required.*

- *Competition, with incentives, is achievable for small customers on an individual basis, rather than on an aggregated basis.*

Offer an incentive to customers that switch to a new electricity provider

One major barrier to large-scale switching has been the relatively small dollar savings that have been available to customers. One means to counter this barrier is to give customers a financial incentive to switch to an alternative provider, as many telecommunications providers have done.

Connecticut considered, and almost passed, this incentive during the 2002 legislative session. Ultimately, this approach was rejected as too burdensome for the default service customers that would have paid for the incentive.

Assign customers to a new provider

Some proponents of restructuring maintain that the best way to support new players in power markets and to get customers accustomed to the idea of buying power from competitors is to assign them to a new electricity provider. Customers could be assigned to new providers in several ways: through random selection, by assigning them to new providers based on the proportionate market share that those market providers have as of some date, or through other mechanisms. The providers could be selected through a qualification process at the utility commission, or could be selected through a bidding process conducted by the commission.

Critics of a policy such as this suggest that it is not competition or customer choice, but that it is simply government assigning customers to new providers, regardless of their desires. Proponents suggest that this policy is worthy of consideration because it is needed as an interim measure to jump-start a competitive market.

Reduce barriers and costs of switching

The cost to secure new customers has been significant. One way to address this is to allow switching to occur through Internet transactions. Electronic commerce is becoming a common part of retail businesses. It can reduce transaction costs, and reduce the effort required of customers. Regulators would still have to assure that shoppers are receiving sound information about choices, and that other consumer protection lessons learned from e-commerce are applied to electricity marketing.

Raise the standard offer price now given to customers that do not switch providers

In their efforts to provide an immediate benefit and protections to consumers, most states either froze or mandated a reduction in electric rates, creating a low default service price. One option to stimulate competition is to raise the default service price and, by doing so, replace the fundamental policy of lowest-possible-price default service with a philosophy in which default service is a higher-priced "safety net."[56] Policymakers must find a balance between the two strategies of either raising electricity prices to encourage competition or keeping prices low to protect consumers' household budgets.

Revise rules for customers moving on or off the standard offer

Rules governing leaving and coming back to the standard offer default service offer consumers a safety net, if customers are allowed back to the regulated service at a predictable rate. It is not desirable, particularly from the standpoint of the default supplier, however, to see customers entering and leaving default supply several times during the year. The default supplier is forced to maintain sufficient power reserves – and pay for those power requirements – to cover the unpredictability of customers that leave or come back to the standard offer.

Policymakers might consider three approaches:

1. Restrict movement

One approach would allow customers to return to default supply, but then the customer would be required to stay for some time. The customer could be required to stay for a year, or, borrowing from health insurance policies and practices, there could be an open enrollment period for a few weeks each year when switching to a competitive provider is allowed. This requirement is in place to allow the default supplier to make adequate plans to meet its load.

The requirement that the returning customer stay on the standard offer for one year may have a dampening effect on the competitive market, by keeping customers who might otherwise buy from a competitor from doing so.

2. Charge customers to come and go

Another approach is to allow customers to come and go from the default supply at will, but to charge them for the privilege of doing so. Such a charge could be structured to approximately compensate the default supplier for the costs that it incurs for meeting the needs of these customers. Maine allows customers to come and go as they please, but charges them two times the average of their previous two months' bills.

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[56] Some observers suggest eliminating rate caps altogether, even high ones. Default service would be priced to reflect provider costs. Providers' incentive to keep prices down would flow from either competitive or regulatory pressure.

3. Establish a new rate for customers that have left and want to return to default service

Policymakers could establish a second, regulated rate class that more closely follows the market prices, as in Massachusetts. Massachusetts forbids customers to return to what Massachusetts calls standard offer service once they have left it and, instead, places them in a different service class that the state calls default service. Massachusetts' default service is the generation service that is available to customers that do not receive service from a competitive supplier and who are not eligible for the regular default service because they have left that service or have moved within or into the service territory. As such, default service acts as a "generation service of last resort."

Policymakers could offer three generation service options: 1) competitive service, provided by competitive suppliers; 2) default service; and 3) market-based default service. The price that the customer pays for generation service depends on the type of service the customer receives.

Treat new customers differently from old customers

New customers to the default provider can be treated differently from existing customers. Two options are possible.

Market-based default service

Place new customers in the same market-based default supply as customers who have left and now want to return to default supply. This market-based default supply option more closely tracks market prices and is the same as described in the third approach described.

Require new customers to choose

Require new customers to make an affirmative choice of provider when they sign up for electric service. This choice would consist of any competitive offerings, as well as the standard service offered by the default service provider or the market-based rate described above. Customers not choosing could be assigned randomly to a provider.

Finalize rules for information disclosure

Uniform disclosure of price, fuel source and environmental information provides a way for consumers to compare the competitive products being offered to them on a consistent basis. Disclosure also gives consumers of monopoly electricity providers the opportunity to understand how their power is generated. It becomes particularly important when marketers make claims that the products they are offering have "green" attributes. Since one of the main ways in which marketers have tried to distinguish their products is to make "green" claims, this can be important.

Disclosure can be used in monopoly or in competitive markets; although in monopoly markets it is viewed as primarily an *educational* tool for consumers. In California, where few small consumers moved to a competitive provider, recent Lawrence Berkeley Laboratory data showed that well over half the consumers who had received a product disclosure label did not realize they had received it.

Examine possibilities for advanced metering through a pilot program

Advanced metering allows power providers to better manage demand and to offer incentives to customers to reduce demand at times when their reduction in demand would be most useful. When accompanied by price signals, advanced metering allows customers to shift their load from expensive, peak periods to less expensive, more efficient off-peak times. New products may attract more switching. Two types of policies for metering are real-time metering and time-of-use metering. Each has different costs and different benefits.

Real Time metering

Real time metering, generally used for the large customers, allows customers to adjust their electricity usage very quickly–often several times a day–to take into account changing electricity prices. The prices that customers with real time meters and appropriate tariffs pay for power change in tandem with wholesale electricity markets.

Real time meters benefit customers that have an incentive to watch their electricity prices closely–customers that use a great deal of electricity. They may be less useful to smaller customers, given the smaller economic value of adjusting very small electric loads. A real time meter costs approximately $200.

Time-Of-Use programs

Time-of- use programs may involve advanced metering. For example, Washington's Puget Sound Energy ran a time-of-use metering and rate pilot program for its residential customers. Puget's customers get feedback on their usage and can adjust their usage according to that feedback and to rates that are higher during peak times and lower during off-peak times. Meters for this type of time-of-use program cost considerably less than the real time meters– approximately $85 installed, or less if the meters are leased rather than sold. The Puget program initially prompted a shift of between 5 percent and 10 percent from on- to off-peak times. Sustained reductions in peak demand can save money for all consumers. Other innovative pricing approaches may promote more efficient consumer behavior.[57]

Although the cost of real time meters is high, a market may yet exist for such a service in small customer markets. An option for policymakers to consider is to test the market for real-time meters for smaller customers through a pilot program. This pilot program would address a number of issues, including:

a. *Who pays for the meters?*
b. *Who owns and controls the information that the meters produce?*
c. *How will different classes of customer use such information?*
d. *Does the information generated by real-time meters and real-time pricing offer a benefit to different segments of consumers?*
e. *Can such information be used to stimulate greater demand response, rather than the standard, averaged electric rates that most consumers currently pay?*

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[57] Rosenfeld, Arthur, Michael Jaske, Severin Borenstein, *Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets*, The Hewlett Foundation. 2002. http://www.ef.org/energyseries_dynamic.cfm .

f. *What is the best structure of a real time pricing program? For instance, should it be combined with a safety-net cap on rates to ensure that they do not increase too much in a short period?*

Advances in pricing and metering can significantly accelerate the acceptance of price-responsive demand response programs.

Go Slow

The second set of policy options explores strategies to bring benefits to small electricity customers through means other than individualized, customer-by-customer retailing. It makes four assumptions.

- Retail competition, structured in a way in which the smallest customers would be approached on an individualized, customer-by-customer basis, is unlikely to attract marketers in the near term, nor is it likely to attract a great deal of interest on the part of the small customers themselves.

- The retail market will not stimulate private aggregators for the small customers because of the costs of doing so.

- Aggregating offers a way to reduce to a minimum marketing costs and what customer efforts are required in order to switch providers.

- For some options below, choice of product, if not always choice of product provider, is a desirable goal. Choice of provider either fits or does not fit into each of these options; these options can be structured to either shut down the competitive market for small customers or to leave it open.

Offer a regulated portfolio of choices to small consumers.

One policy option is to offer small customers a choice of product, but not necessarily a choice of provider. Small customers in Oregon do not have the ability to choose a new provider as large customers do, but they can choose from four or five products. Policymakers could adopt a variation of the Oregon program, taking advantage of the lessons from the program described earlier in this report.

This option can be set up in the presence of or in the absence of the ability to select an alternative provider. Establishing such a policy option when customers can choose an alternative provider may discourage competitive providers of green or time-of-use products. Monopoly states can also adopt this policy.

Bid out the privilege of supplying default consumers.

Assuming that marketers will not actively market on a customer-by-customer basis to small customers, it still is possible to bring competitive forces to the market by putting out to bid the load of these customers. The default supplier(s), in other words, can be chosen through competitive means. Maine has chosen the alternative approach of putting out for bid the privilege of supplying energy to non-choosing customers.

Authorize opt-out aggregation.

Opt-out aggregation was discussed in section 3. The following summarizes its advantages and disadvantages.

<u>Advantages</u>

- Opt-out aggregation reduces marketing costs for power marketers and dramatically reduces the number of steps that a consumer must take in order to participate in the competitive market.
- Opt-out aggregation can pool complementary electric loads.
- Opt-out aggregation can offer an element of local control over electricity purchases, moving the decision-making process closer to the ultimate consumer.

<u>Disadvantages</u>

- Some customers still will not understand what is happening until after they have been switched.
- Opt-out aggregation requires expertise and is not without costs to the aggregator.
- Aggregation, if successful, will have the effect of quickly separating large groups of customers from the default supply. If the remaining customer base is characterized by a worse load factor than those customers that left, aggregation could have the effect of raising prices for the remaining customers.

Reexamine how the decision is made about when and whether to phase out default service options.

Policymakers in several states have set a date certain when default service expires. There are alternatives. The state may remove the expiration, it may elect to continue to rely on an expiration date, regardless of circumstances, but it can change the date, or it could articulate a set of conditions for state regulators to evaluate whether the market is sufficiently developed to sustain removal of default service.

<u>Go Back</u>

This policy option conveys a simple idea: competition as an ideal has not worked as policymakers expected. Perhaps the necessary foundations, including a fully functioning wholesale market with customers responding to market price signals, do not exist. Perhaps political trade-offs placed too many tethers on competitive forces for them to work. For whatever the reason, the time may not be right. Therefore, policymakers would supervise a return to fully regulated public service.[58]

Among the assumptions in a state considering going back are:

- The wholesale electricity market will not be settled for some time, and will not support retail competition until it is settled.
- Customers would rather have the stability of a single electricity provider.
- Discussion of retail electric competition in some states feels deceitful since no competition among suppliers trying to sell power to consumers is happening.
- Financial markets will be settled by a more stable cash stream to support capital needs.

Restore obligation to serve responsibility to a single entity in a utility service area

The local utility can be directed to assume the responsibility to serve all customers in its service area. In the alternative, another entity can be assigned power supply responsibility.

Whether or not the distribution utility divested generation, the provider of last resort can enter the wholesale market and acquire a portfolio of generation ownership and contracts using portfolio management techniques to manage market risk.

Policymakers taking this step should try to convey a message of stability, enabling utilities to have confidence that its prudently incurred contract commitments will be balanced by revenues from consumers. This stability will contribute to capital markets supporting necessary investments in infrastructure.

A state taking this action, as California and several other states are contemplating, should consider the transmission and public interest policies, below.

Government Steps In

The fourth set of policies offers means to further involve the government–defined as either the state or as local or county government–in the provision of power to consumers. It relies on the following three assumptions.

- The competitive market will not result in meaningful competition for the small electricity consumers.
- Local control is important to the power industry.

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[58] For a thorough examination of the challenge of electric industry restructuring and deeper exploration of whether success is a reasonable expectation, see Rosen, Richard A., Freyr Sverrisson, John Stutz, Can Electric Utility Restructuring Meet the Challenges It Has Created? Tellus Institute, 2000.

- Private interests will not provide the benefits to consumers that a public, organization would provide. The private, investor-owned model for the power industry offers only a short-term view of the investments needed in the industry. Government involvement will shift the investment focus to an outcome based on longer-term investments that benefit consumers.

Establish public power districts to build or buy generation for local consumers, or to serve as retailer for electricity

A policy that would establish public power districts is similar to new initiatives in a number of states to bring a greater degree of local control to the power industry. Such an effort could focus not only on purchasing existing generation assets. The state would need to authorize formation of such entities.

Essential to implementing such a plan are an assessment of risk by the government, including such issues as government bond rating, risk management costs, and liabilities. A transition plan to deal fairly with long-term utility contracts and commitments of utilities or default service providers is also necessary.

Establish a state commission to buy or condemn generation resources.

There are a number of proposals to increase public ownership of utility assets. In Oregon, for instance, there are proposals to issue public bonds to buy the assets of Portland General Electric. One option is that the City of Portland would buy the assets; the other is that a consortium of counties would do the same.

Government control can mean more local control over generating assets. However, the amount of load covered by the government-owned generation still leaves exposure to risks. Government-owned generation is subject to failures and natural shortages and may force a move to spot markets

Transmission and Public Interest Policies

Regardless of what course a state takes, or if a state is committed to regulating vertically-integrated monopoly utilities, the following policies merit consideration.

Transmission Related Policies

Few utilities made major investments in the transmission system throughout much of the 1990s. There are differing views on whether this is bad, but now, reliability margins, as represented by near term need for new power lines, are thinning in several places. When merchant power plants consider building power plants, and when banks consider financing those power plants, they particularly consider whether they will have firm and reliable access to the transmission system to allow them to ship their power to market. The rules that govern the transmission system require attention and system expansion practices need improvement.

States and the federal government share jurisdiction over the transmission system. The federal government has jurisdiction over the rates and terms that transmission system owners can impose for others to use their transmission lines. The federal government also holds jurisdiction over the regional institutions that are being set up to govern the transmission system. The Federal Energy Regulatory Commission oversees these aspects of the federal control over the system.

State jurisdiction over the transmission system falls into four primary areas:

- Siting of transmission lines,
- Financing transmission,
- Participating in regional planning for transmission, and
- Taxation of transmission companies.

Siting transmission

The most important formal state role in the transmission market today is in siting of new transmission lines. Siting law is complex, particularly when considered in the context of a situation in which the need for power is in one state, yet the power plants and power lines may be built in any state. Policymakers might examine three siting concerns:

- Explore possibilities for regional siting and collaboration in permitting and building of new transmission lines.[59]
- Consider evaluating the "need" standard for transmission in the context of regional needs for power vs. in-state transmission impacts in light of alternatives, including resources at or near the customer.
- Consider means to streamline the siting process for transmission lines, especially inter-state lines.[60]

Financing transmission

States could, if it desired take a direct role in financing new transmission either by making direct cash contributions to new transmission or by backing transmission financing with the credit of the state.

Numerous issues will need to be considered before taking such a step. Transmission is expensive, and any meaningful contribution could require either a significant cash outlay or the assumption of a significant risk. The state would need to consider the costs and benefits of taking such a step carefully. It is worth noting that no other state has yet taken such a step because of the risks and costs involved.

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[59] See Brown, Ethan, *Interstate Strategies for Transmission Planning and Expansion,* NGA Electricity Infrastructure Task Force 2002.

[60] States should not bear the full burden of improving the siting process. Siting proposals by the industry can better anticipate public concerns. See Meyer, David and Richard Sedano, *Transmission Siting and Permitting*, U.S. Department of Energy, 2002.

Transmission planning

The electric power industry is now a regional industry, yet most laws that govern the industry are either state or federal laws. State regulators already are involved in regional efforts on transmission. Some of these efforts may be more effective with state legislation that supports regional planning and regional collaboration.[61] States will evaluate this benefit against a potential or perceived loss of control over state decision-making and resources.

A planning process that considers all solutions to system needs, including customer-based solutions, is likely to produce better results from the perspective of rates and environment. This suggests that a planning horizon of a significant length (7-10 years) is desirable. Integration with the planning by Regional Transmission Organizations formed as a result of FERC's Order 2000 will maximize the value of state efforts.

Tax and other financing considerations

States have the authority to tax transmission companies and to offer tax incentives for transmission. It would be possible for states to offer a tax incentive for building new transmission, although it would be important to determine what transmission investments might be made without such incentives. Similarly, states could offer incentives for installation of new and efficient transmission technologies.

States also might be able to use financial payments to ease the transmission siting process. Wisconsin recently enacted legislation to offer payments to communities affected by new transmission installations.

Finally, states have the authority to ensure that whatever system is set up takes into consideration the alternatives to building new transmission. In some situations, it may be less expensive to build small-scale generation instead of building more transmission and shipping in more power. Similarly, it may in many cases be more cost-effective to make investments in efficiency in order to take the load off the transmission system. Such investments can, in some cases, obviate the need to build, finance and issue permits for new transmission lines.

Planning and Public Benefit Policies

In addition to the policies described above, several policy options are available that do not fit neatly into any one of the above categories. These could be enacted in combination with any of the above policies.

Establish a one-time or ongoing state energy planning effort

An energy plan and planning process provides one method for states to establish planning priorities to guide industry, state agencies and policymakers in their long-term decision making process. An energy plan may address the following non-exhaustive list of issues.

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[61] Brown, Ethan, *Interstate Strategies for Transmission Planning and Expansion*, NGA Electricity Infrastructure Task Force 2002.

- Will the state set a priority on developing certain resources, such as in-state coal or renewable energy?
- Will the state make a priority of encouraging competitive energy markets?
- Will the state make energy efficiency in public and private facilities a priority, and through what means will it do so?
- How will the state marry economic development with energy use, prices and infrastructure development?
- What long-term opportunities exist in certain new technologies such as distributed generation?
- What long-term issues might the state need to address in planning for new air quality regulations as they affect the energy industry?
- What long-term issues must the state address with regard to gas supply availability?
- What long-term issues must the state address with regard to electric transmission?

Energy plans are generally developed by state agencies, including the energy office, public service commission, the department of environment and – sometimes – the transportation and economic development offices. Such plans generally are developed using a mixture of public input and detailed analysis.

Establish a renewable energy portfolio standard

As discussed in Section III, B., the renewable portfolio standard is a requirement placed on any retail seller of electricity that a specified percentage of the kilowatt-hours that it sells shall come from renewable energy sources. Percentages vary from one or two percent (particularly for portfolio standards that specify reliance on solar energy, which tends to be more expensive), up to 30 percent in Maine. Maine already relies on renewable energy for more than 30 percent of its generation, so this was a means of preserving the use of in-state resources. California recently passed a 20 percent portfolio standard, and typical percentages range from between five and 15 percent, usually phased in over a period of several years. Fourteen states have a portfolio standard in place.

Establish an emissions portfolio standard

As was also discussed in Section III, B., the Emissions Portfolio Standard is a requirement placed on any retail seller of electricity that the total emissions of a particular gas associated with the electricity sold, divided by the amount sold, does not exceed a certain level. Such a requirement might be desirable to prevent retailers from reacting to local environmental limits by buying power from generators elsewhere that would not meet those local standards.

Establish a renewable and advanced energy development fund

A state that wants to promote the development and deployment of advanced energy systems and renewable energy can set up a fund for that purpose. Several states have chosen to do this. The purposes include addressing market barriers to emerging generation technologies for which there is a public interest to deploy faster than would otherwise occur. This effort can be seen as replacing research and development commitments that utilities have curtailed or abandoned as part of electric restructuring.

Maintain structural support for energy efficiency

Energy efficiency has the attributes of being inexpensive, of slowing or reversing increasing pressure on the transmission system, of being targeted to delay or avoid more costly system expenses, and of avoiding emissions of pollution. Yet market barriers remain that deter investments that benefit all citizens. Consumer-funded energy efficiency programs address these barriers.

States can require all retailers to support energy efficiency in various ways. Distribution companies can include energy efficiency in their responsibilities. Or a centralized energy efficiency service provider for the state can be created. This central provider would not be concerned about the effect of reduced sales due to efficiency on utility net income. The central provider could be in or out of government and could be selected competitively.[62]

Energy efficiency can also be supported through the adoption of reasonable appliance and equipment standards and building energy codes.

Reduce barriers to distributed generation

Highly efficient and clean generation resources can be deployed on customer premises. Yet rules discouraging these developments persist.

States can adopt rules governing the interconnection of customer generation equipment to the power grid in a way that is fair to both the customer on the one hand, and to the utility and the rest of the customers on the other. Other regulatory reforms can promote further progress in the use of distributed generation.[63]

States should take care to assure that customer-sited generation meets reasonable environmental standards and does not add to the environmental footprint of electric power generation.

Require default service providers to practice "portfolio management" in acquiring resources

Whether monopoly or competitive, all states have a provider of last resort. Regulators are responsible to see that this provider delivers power in the public interest. This standard includes "least cost," but also includes other considerations, like avoiding volatility, managing risk, and using a long-term perspective.

States can require all providers of last resort service to use a rigorous process for resource acquisition that is more "risk aware" than is in place now. For example, to assure that the state is

[62] *Energy Efficiency for Risk and Reliability Management*, Regulatory Assistance Project IssuesLetter, September 2002.
[63] See The Distributed Policy Series from The Regulatory Assistance Project, http://www.raponline.org.

not exposed to unduly volatile market conditions at some future time, the process could ensure that no more than a maximum percentage of resources serving default customers expires and must be replaced at any one time.[64]

Encourage performance based regulation for distribution companies

Performance based regulation can improve the alignment of utility and public interests by creating financial incentives for quality service in matters of most importance to consumers. Regulators can measure customer service, system reliability, and energy efficiency and other programs, and set performance goals. If the distribution company meets or exceeds the performance goal, it can be allowed to keep some financial benefits from improved productivity, and allowed earnings can be on the high side if service quality is also high. States can encourage regulators and companies to consider performance based regulation.

Encourage meaningful corporate codes of conduct and affiliate transactions rules

In monopoly and competitive states, corporate structures are getting more complex as managers seek new ways to mix regulated and unregulated operations within one firm. Regulators have a responsibility to assure that revenues from monopoly consumers are not subsidizing more risky affiliates, or that the monopoly status of the firm does not confer an unfair advantage on an affiliate in a competitive market.

Codes of conduct assure that management of the corporation keeps control of information and other practices such that the activities of the monopoly do not confer an unfair advantage on a competitive affiliate. The distribution company has a great deal of information on each of its customers. This information should be available to all, or none, but not some, and especially not just its affiliate.

Transaction rules assure that prices paid for goods and services between the affiliates are fair. Typically, these rules address whether book value or market value is used. As corporations refine their structures, they will move assets in and out of the regulated entity. It is important that consumers are treated fairly, and do not somehow absorb losses incurred by "at risk" affiliates.

Resolve wholesale market rules

Efforts toward retail electric competition were handicapped from the start because wholesale rules were not changed to be supportive of retail markets without a host of changes to wholesale market rules. States' efforts to work around these deficiencies serve to illustrate the problem. Competitive retail markets need some level of price responsiveness connected to wholesale markets. Beneficial market reforms which are already underway in some parts of the U.S. include: more liquid markets using day ahead and same day market settlements; locational pricing that reflects system congestion; and full use of customer resources, including demand response, distributed generation and energy efficiency. These reforms are critical steps toward a working electricity market that values resources appropriately and that maintains equivalent power on the part of both supply and demand.

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[64] Harrington, Cheryl, et al, *Portfolio Management: Looking after the Interests of Ordinary Customers in a Market that Isn't Working Very Well*. The Hewlett Foundation. 2002. http://www.raponline.org

C. CONCLUSION

Electric restructuring is only one illustration of the oft-cited observation by Justice Louis Brandeis that the states are laboratories for democracy and innovation.[65]

The policy options above represent a significant range of options for state policymakers to consider while in the midst of one of the most complex experiments the states have taken on yet. The writers contend that all states that have taken steps to restructure their electric industries will be considering some of these policies, either to apply lessons learned and fine tune progress that has been made, to address specific dates in restructuring statutes and rules when initial decisions expire and may need to be revisited, or to deal with problems that need correction.

Whatever policy adjustments states decide to make, they are advised to avoid the trap of anticipating a single future. The last several years should remind all that surprises happen with surprising frequency for such a heavily analyzed industry. Policies most likely to contribute to the public good whether fuel prices go up or down, or whether competition flourishes or not, or regardless of the outcome of countless other variables should have a strong appeal.

To maximize effectiveness in these policy tasks, and to make sure that objectives are clearly identified and solutions clearly address the objectives, good communication between legislators, regulators and executive branch energy policy leaders is important.

Regional communication and, where possible, cooperation, is also likely to better account for the regional electricity marketplace that is further evolving, and will help to assure that the innovation of one state does not add risk to its neighbors.

[65] "It is one of the happy accidents of the federal system that a single courageous state may, if its citizens choose, serve as a laboratory, and try novel social and economic experiments without risk to the rest of the country." *New State Ice Co. v. Liebmann*, 285 U.S. 262, 311 (1932).