Electricity Restructuring Activities in the US:

A Survey of Selected States

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Summary of Alternative State Approaches

The 1990s: Growing Enthusiasm for Restructuring

About one half of the states in the U.S. embarked on the process of electric restructuring during the 1990s. There was a rising tide of enthusiasm for restructuring through 1999, and it seemed likely that other states would join in the process. At the federal level, there was talk of mandating restructuring, and the Federal Energy Regulatory Commission (FERC) came to be increasingly committed to competition in wholesale electric markets and fair access to the transmission grid by independent power producers.

Reassessment in 2000/2001

In 2000/2001, however, the unexpected and severe California electricity crisis was dramatic proof of the dangers of embarking on restructuring in unfavorable circumstances and without a well-designed market structure. The wholesale electricity price increases in California and other regions, combined with delays in forming regional transmission organizations (RTOs), and difficulties in getting the retail market established for residential and small business customers, sobered up the enthusiasts, and led to a nationwide reassessment of restructuring.

Variety of State Responses

This survey is intended to document the responses of different states across the country to these developments. We have selected fifteen states – some of which we have discussed in detail, others in a more summary or focused fashion. The states have been selected to show a variety of responses, and to attempt to explain why the responses have differed.

Some states had already established workably competitive wholesale markets with direct access by large business customers and even some residential and small business customers, and it is not surprising that most of them decided to stay the course. In our survey, Illinois, Maine, Ohio and Pennsylvania are in this group.

On the other hand, some states that had not yet embarked on restructuring, including Florida in our sample, decided to wait and see. Colorado, which is also in our sample, had already decided not to restructure. Others, including Vermont in our sample, had come close to restructuring, but have also decided to wait and see.

Of particular interest for states like Arizona that have gone some distance toward restructuring, but have not yet reached the point of no return, are those states that were in the process of restructuring, or were on the verge of restructuring. What have they done, and why?

We have picked one state, Texas, that has remained totally committed to restructuring, and opened up its retail market to competition on schedule on January 1, 2002. The Texas authorities believe that the experience of the first months of retail access is bearing out their optimism.

Few if any other states that are on the brink of restructuring have remained quite as sanguine about the prospects as has Texas. In our sample, Montana, New Mexico and Oregon have all delayed the process in one way or another, and retained the protection of utility regulation for an extended period. Two states – California itself and its neighbor Nevada – have completely abandoned restructuring, and one, Arkansas, which has already decided on a two-year delay, is considering a prolonged delay.

Lessons from the More Successful States

Broadly, certain lessons can be learned from those states that had already undergone electric restructuring – more or less successfully – before the California crisis erupted. In these states – including Illinois, Maine, Ohio and Pennsylvania in our sample – the wholesale market is functioning better in Maine and Pennsylvania, with established regional ISO's. And even in these states, their ISO's and related power pools – NEPOOL and PJM respectively – have seen unjustifiably high prices at times, barriers to merchant power interconnection, and transmission pricing and congestion problems. In Illinois and Ohio, it is proving difficult to get the Midwest RTO off the ground and approved by FERC. This could result in shortfalls of supply or transmission inadequacy which could undermine competition and lead to unreasonable price increases.

In all of these four states, it is proving difficult to get retail competition established in the residential and small business market. There is considerable variation between different parts of each state, e.g., in Ohio, the northern Ohio service territories of Cleveland Electric Illuminating Company and Toledo Edison account for almost all the switching in the state. The utilities' high prices provide the motive, and the formation of large governmental aggregators provides the means. Governmental aggregation is made relatively easy in Ohio because it can be of the opt-out variety – customers in a municipal area are included unless they choose to opt out.

In Illinois, the Chicago area served by Commonwealth Edison Company (ComEd) accounts for most of the state's switching. Again, the motive is provided by ComEd's high rates. In Illinois, aggregation has not been a factor, however, rather it seems that the sheer concentration of customers in Chicago makes it feasible for marketers to sign them up with incurring excessive acquisition costs.

In Maine, the legislation provides an alternative, indirect, means of bringing competition to small retail customers. Standard offer service is not part of the distribution utility's scope, it is put out to bid and awarded to competitive providers. Maine regards this approach as successful.

In Pennsylvania, the “poster child” for retail restructuring, the development of the small retail market is also very uneven. Pennsylvania's reputation was based on the adequacy of its "shopping credits" – the credit given by utilities to customers who no longer took generation service. The deduction of a relatively low exit fee for utility stranded costs, and the inclusion in the shopping credit of a retail adder to reflect alternative providers' retail overhead and marketing costs, are among the methods for increasing shopping credits. However, Pennsylvania's approach has not proved that much more successful in the face of market price increases than the approaches of other states. Fully 30% of the customers who had switched to the competitive market in Pennsylvania have returned to utility standard offer service in the past year or so.

Optimism in Texas and Pessimism Elsewhere

Why did Texas go ahead on January 1? The authorities checked through the problems of California and decided that their own situation, and the structures that the legislature and commission had put in place, would prevent anything like that from happening in Texas. Perhaps the most significant differences are in the wholesale generation market. The Texas market benefits from having state control of its own independent system operator. The ERCOT-ISO is encouraging the timely and adequate construction of new power plants and transmission lines, and there appears to be sufficient generation capacity.

The Texas legislation also favors the creation of a workably competitive wholesale market by requiring utilities to auction off 15% of their generation to competitive providers, and by limiting the ownership of generation assets by any one corporation to no more than 20% of the market.

Regarding the Texas retail market, it remains to be seen whether it develops for residential and small business customers as well as for large business customers. However, early signs are promising: a number of customers appear to be switching suppliers and governmental aggregation has already succeeded in gaining a foothold in the market.

By contrast with Texas, Nevada, which had come close to allowing its two principal investor-owned utilities to divest their generation assets, abandoned its restructuring effort. The wholesale market simply wasn't ready for it. Similar considerations led to a successful effort by Montana to retain effective jurisdiction over the generation assets of Montana Power Company, even though those assets had already been divested to PPL Montana, a non-affiliated company. And in Virginia, fearing that loss of jurisdiction would result in higher prices – Virginia utilities having low embedded costs that would likely remain below the level of market prices – the Commission is trying to maintain jurisdiction by restricting transfers to utility generation divisions, not separate corporate entities.

Summary and Recommendations

In summary, there are very few states that have experienced benefits from retail competition to date – and very few small customers have seen significant, lasting benefits. Yet, experience has demonstrated that there are risks associated with retail competition – risks of market power and increased electricity prices, risks associated with the loss of state regulatory jurisdiction, and even risks of electricity market failure. How states are responding to this changing situation depends as much on their views regarding markets versus regulation, as on the evidence provided by the experience to date. In looking at emerging competitive markets, state authorities seem to be able to see the glass as either half empty or half full.

Our foremost recommendation is that the risks must be carefully weighed against the potential benefits before establishing a competitive retail electricity market. Retail competition should only be pursued if it can be demonstrated that the benefits outweigh the risks.

A smoothly functioning, well-designed, competitive wholesale electricity market is one of the most important conditions necessary to reduce the risks and increase the potential benefits of retail competition. The appropriate design and structure of the retail market is also necessary to achieve the benefits of retail competition; including the design of the shopping credits, the availability of competitive marketers, and provisions for aggregation or competition to provide standard offer service. If these conditions are not in place, the risk may not be worth taking.

Arkansas

Summary

Arkansas is a good example of a state that was moving in a deliberate manner toward retail competition until 2000/2001, but then decided -- in light of the California situation as well as local considerations -- to delay restructuring for two years. In 2001/2002, further delay or even repeal of the restructuring legislation is under discussion.

Among the local considerations that contributed toward the decision to delay restructuring were the following. First, Arkansas enjoys relatively low power costs, and there was the fear that in a competitive regional electricity market, prices might rise. Second, the region's utilities, who are members of the Southwest Power Pool (SPP) are moving slowly in their compliance with FERC directives to form an RTO.

In a nutshell, with the wholesale market unready for retail competition, the Arkansas Public Service Commission and state legislators decided in 2000/2001 that Arkansas need not be in a hurry to embark on the complex procedure of opening up the retail market to direct access. In 2001/2002 the debate has gone further than merely delaying restructuring; now the PSC has become skeptical and the whole endeavor is under review.

Profile of State Electricity Situation

The principal electric utility company in Arkansas is Entergy Arkansas, Inc., a subsidiary of Entergy, Inc., which, through subsidiaries, dominates the electricity industry across the middle south from east Texas through Louisiana and Arkansas to Mississippi. It has joined the Southern Company, which abuts Entergy to the east, in the Southeastern Electric Reliability Council.

The other electric utilities operating in the state have relatively small pieces of the market -- Southwest Electric Power Co. (SWEPCO, a Central & Southwest subsidiary), Oklahoma Gas & Electric, a number of rural electric cooperatives and a couple of municipal systems.

The generation system is quite diversified, with coal-fired, natural gas-fired and nuclear generators. In the past, the most controversial issue was the FERC allocation of a large share of the costly Grand Gulf nuclear generating station to Arkansas. This gave rise to potential stranded or unrecoverable fixed costs.

The Arkansas Public Service Commission (PSC) is the state's regulatory agency.

Restructuring Legislation and Regulation

Act 1556, the Electric Consumer Choice Act of 1999, was signed into law on April 15, 1999, and provided the basis for restructuring in Arkansas. Act 1556 mandated retail open access (ROA) no sooner than January 1, 2002 and no later than June 30, 2003, the exact date to be set by the PSC. Those dates gave the PSC a timeframe to work with in preparing the industry and its customers for restructuring.

Before and after the passage of Act 1556, the Arkansas PSC conducted proceedings to investigate restructuring issues such as Entergy's stranded cost problem. The statute has provisions for stranded cost recovery. For those customers who remained on standard offer service from their incumbent utility, rates would be frozen for one year. If, however, the utility seeks to recover stranded costs, its standard offer rates would be frozen for three years. Utilities were required to file functionally unbundled tariffs showing, at a minimum, generation, transmission, distribution and customer service components. Other provisions related to such matters as licensing of suppliers and aggregators, competitive metering and billing, customer protection.

Concerns over the structure of the power market and the possible exercise of market power in a deregulated wholesale power market have been addressed by the PSC. In Docket No. 00-048-R concerning market power, opened in February 2000, utilities were required to file market power studies. If a company was found to possess market power, it would have to file a market power mitigation plan. Mitigation plans may include such measures as price caps, transitional standard offers, generation sale through long-term contracts, and asset divestiture.

Delays in the Restructuring Schedule in 2000/2001

The statute requires the PSC to submit annual progress reports to the state's legislature, the General Assembly. In 2000, the PSC conducted a proceeding in which interested parties could address these issues before the submission of its first annual report. The report was titled *Progress Report to the General Assembly on the Development of Competition in Electric Markets and the Impact on Retail Customers*, and was submitted November 28, 2000.

The questions addressed in the proceeding and reported to the legislature focused primarily on the state and region, and included forecasts of generation prices. The PSC also noted that it had "closely followed developments in other regions of the country including, but not limited to, the problems encountered in some parts of the California markets as well as other states in the West and the Northeast, the price fluctuations in the natural gas markets, and developments regarding RTO issues." (p. ii)

The PSC developed a two-part "readiness" test for retail competition: (1) was there a market structure that was ready for competition, and (2) would competition result in net public benefits? The PSC convened a hearing on October 11, 2000 in which it noted that many of the parties believed that the statutory timeframe was too tight. The PSC came to the conclusion that the schedule "would not provide sufficient time to allow the development of market structures that could support a competitive, fully functioning retail market for electricity, and would not provide a reasonable opportunity for all consumers to realize net benefits from competition." (p.ii)

Regarding the development of the wholesale market, the PSC was not convinced that the region would have a comprehensive and effectively-functioning RTO in time for retail access in 2002/2003. Yet, "The Commission is convinced that a workably competitive wholesale generation market is a prerequisite to the effective functioning of retail generation competition." (p. 17)

The electricity providers were supporting the efforts of the Southwest Power Pool (SPP) to form an RTO, which was then expected to be operational by the end of 2001. However, Entergy was planning to establish a for-profit Transco, which would have to enter into an operating agreement with the RTO. Furthermore, the Entergy system's operating agreement would have to be modified. And finally, OG&E, SWEPCO and Empire District Electric would not commit to joining the RTO unless certain conditions were met. "It is simply not reasonable to expect that all of these tasks will have been completed and that the RTO/Transco will be fully functional within the timeframe currently contemplated by Act 1556." (p. 18)

The PSC did not think Arkansas would run the same risk of high prices and power emergencies as California, because conditions in Arkansas were different. It was easier to site new power plants in Arkansas, and in fact a number of plants were under construction or are planned. The formation of an effective RTO should "encourage expansion of the transmission system." (p 21) But the PSC was still concerned: "However, there are still significant transmission issues that must be addressed and market power mitigation and enforcement remedies that must be established as a prerequisite for an effective competitive marketplace that could produce net benefits." (p. 21)

Regarding the benefits to customers, staff consultants made a forecast "that customers would pay higher generation costs under competition than under continued regulation for the foreseeable future." (p. 3) Some parties pointed out that entry into the Arkansas generation market was easier than in California, that there would be no mandatory purchase of power through a power exchange, and that the standard service package for small customers would mitigate price volatility. (p. 6) They also disagreed with the magnitude of the retail adder estimated in the Staff study, the mark-up of retail over wholesale power costs. The consultants estimated one cent per kWh, compared with Entergy's estimate of a quarter of one cent (pp. 15-16). The PSC was, however, clearly influenced by the views of the Staff consultants.

In summary, the PSC concluded that retail competition was not expected to meet either of its “readiness” tests in the 2002/2003 timeframe. A Joint Agreement was negotiated between the parties. Pursuant to that agreement, the PSC recommended to the General Assembly that ROA be delayed to no sooner than October 1, 2003 and no later than October 1, 2005, with the PSC being authorized to set a date within this range.

Three other points are of interest in the Arkansas PSC’s November 2000 *Progress Report*. One is that the PSC continued to believe that it was appropriate to plan for retail competition, and that “the statutory framework embodied in Act 1556 is an appropriate one to transition from regulated to competitive electric generation service.” (p. iv) Moreover, “Most of the parties agreed that wholesale competition can provide some but not all of the benefits that consumers will realize when ROA is implemented.” The PSC cited the Staff’s view that “Over time, wholesale competition should provide lower costs and greater efficiency. Retail competition can offer pricing options, source options, and payment in-service options.” (p.7)

The second point is that the PSC recognized how important it was to give market participants a framework within which they could make their planning decisions. “A reasonable implementation window needs to exist as a target date for purposes of providing investment and planning direction to the market participants, both regulated and non-regulated. If they have not already done so, the electric utilities must now make decisions regarding acquisition of additional generation capacity. Transition plans need to be developed and large customers have equivalent energy planning decisions to make.” (p. iv)

The third point is a background political point about the process by which the recommendations to the legislature were negotiated. The recommendation was able to receive near-unanimous support, because it left the basic framework of restructuring intact, and restricted itself to a matter of timing.

Increased Skepticism in 2001/2002 Regarding Restructuring

During 2001, the PSC was obviously concerned about the on-going electricity crisis in California. It issued an (undated) 7-page document on its website, *What Happened in California, or Why Arkansas is not California*. It identified the factors that resulted in the market failure in California, and concluded that none of those factors applied to Arkansas. However, it is clear from the issuance of this document that the PSC was finding itself in a defensive posture on the issue of electricity restructuring.

In its defense of the Arkansas situation, the PSC made the following points. First, there is no official power exchange planned for Arkansas, nor is there a mandate for the utilities to sell power into or buy power from the spot market. There is likely to be a high proportion of stable, long-term bilateral contracts (as is the case in most states). Second, the price freeze period is short and default standard service will respond to market prices. Third, demand growth in Arkansas is increasing modestly, supply resources are increasing, and plant siting is not overly difficult, all of which should avoid a constricted supply and demand situation.

The PSC had this to say about market power. "Dealing with the exercise of market power is a problem we share with California, or any other state that moves to competitive generation markets." (p. 7) However, the PSC believes it has broad statutory authority to deal with market power. (The PSC does not make it clear how its authority would prevail over federal jurisdiction in the wholesale market.)

This document represents the PSC's last defense of retail open access. It's conclusion was that, "As we learn from the experience of other states, Arkansas can move ahead confidently, knowing that the California mistakes will not recur here." (p. 7)

The PSC submitted its second annual progress report to the General Assembly on December 20, 2001, titled *Report to the General Assembly Pursuant to Act 324 of 2001 on the Development of a Competitive Electric Market and Possible Impact on Consumers*. The PSC noted that Act 1556 had been amended by Act 324 of 2001, as a result of the recommendations made by the PSC in its first progress report. The date for initiating retail competition had been changed to not earlier than October 1, 2003, but the PSC may delay competition in one-year increments until not later than October 1, 2005.

In Docket No. 00-190-U, the PSC had entered an order on July 6, 2001, asking interested parties to comment on forecast prices under competition compared to continued regulation, and on anticipated market readiness. Before introducing retail open access, Act 324 provided that the PSC would have to find that there would be "net price benefits for customers, particularly residential and small business" (a more restrictive provision than the earlier "net public benefits"), and that "the wholesale market was ready for retail competition." (more pointed than the earlier "market structure" requirement). (p. i)

Applying these more precise tests, the PSC was much more skeptical in its assessment of the prospects for retail open access than it had been a year earlier. "Based on information submitted in Docket No. 00-190-U, and the status of activities at the Federal Energy Regulatory Commission ("FERC"), the Commission believes that continued movement towards retail competition in Arkansas is not in the public interest." (p.i) The PSC recommended "one of two viable statutory modifications:"

> The first option would be the complete suspension of the current statute for a considerable period of time, perhaps going out to 2010 or 2012. The second option would be a repeal of the laws related to retail open access." (p. ii)

There are several considerations that led to this recommendation. No doubt the first was that the atmosphere in the General Assembly had changed, as evidenced by the tightening of the pre-conditions for retail competition. The second was that the tenor of the debate in the PSC hearing room had changed even more. It was no longer a matter of "let's just stick to the issue of schedule." Now, the substantive issue of restructuring itself was the center of the discussion. However, some parties, such as Entergy, while agreeing that a further delay was necessary, opposed an outright repeal of Act 1556.

The PSC Staff submitted ten-year price forecasts, for each utility, comparing competition with continued regulation. For all utility areas except OG&E (which has a relatively small service territory in Arkansas), generation rates would be higher under competition throughout the period, the Staff study concluded. For Entergy, the utility with by far the largest service territory in the state, the cumulative change would be 13.4% higher than regulated rates. This was despite the fact that generation capacity was expected to be adequate, and transmission systems were not expected to pose problems. The PSC saw "no anticipated qualitative benefits" to offset the price increases. (p. 15)

The PSC found that, "Perhaps the most critical key to the development of a workably competitive wholesale market is adequate, non-discriminatory access to the transmission network. Such success is largely dependent on FERC activity regarding RTOs. However, issues that will be crucial in determining whether or not this wholesale market plan will be effective and beneficial to retail consumers include: the price of access and the effect of federal pricing policies on retail customers in Arkansas; the policies surrounding non-discriminatory mechanisms for management of congestion at certain points on the transmission network; and the appropriate cost recovery treatment of additions to the transmission network." (pp. 12-13) Only one of the participants in the proceedings (SWEPCO) believed that a FERC-approved and operational RTO would exist in time to support ROA in Arkansas by October 2003. (p. 7)

The PSC concluded that, "The direction the electric industry will ultimately take regarding retail markets is certainly not clear...Several surrounding states have only begun initial inquiries into whether to restructure the electric industry within their borders, while others have conclusively determined not to move forward anytime in the near future. In this part of the country, only Texas is continuing to move towards ROA...The ERCOT portion of Texas is still moving to ROA, even though the start date for Entergy and SWEPCO in the eastern portion of the state has moved from January 1, 2002 to September 2002." (p. 11)

The PSC's overall assessment of retail competition was negative. "To date, no state has implemented an entirely successful retail competition model. Every state, including Pennsylvania and Texas, that has implemented electric competition has experienced various combinations of price increases, price volatility, and operational problems. Some model may eventually prove to be workable and beneficial; however, there are strong indications that existing models will likely be changed in significant ways." (p. 15)

The General Assembly holds sessions every other year, and its next scheduled session is in 2003. Unless it meets in special session, presumably the fate of Act 1556 will remain in the balance during 2002.

California

The California commission voted to end direct access by retail customers in September 2001. It is not our intention to describe the California restructuring model, which is quite complex, in great detail. Rather, with hindsight, we describe briefly some of the features of the California model that contributed to the state's electricity crisis of 2000-2001. In other words, we are using California as an example of what *not* to do.

1. Power Supply Shortages.

A tight power supply situation resulted in a malfunctioning of the poorly-designed California ISO, and in opportunistic behavior by suppliers which enabled them to manipulate prices. Prices rose far above production costs.[1] Similar, though less extreme, price spikes have occurred in other parts of the country. If the supply of power becomes tight in the bulk power market, it is difficult to avoid extreme price spikes. This is perhaps the most widely applicable lesson of the California electricity crisis.

In the intensity of debate in California over the transition to a new market structure, and the design of that structure, participants took their eye off the ball. They failed to keep abreast of the state's economic boom, with its implications for high electricity demand. The construction of new generation plant, and the upgrading of the transmission system, failed to keep up with demand. Another factor on the supply side was that hydroelectric generation was low, owing to low precipitation.

The California crisis has reminded the electric industry and its regulators of something that they all took for granted under the regulated utility regime -- that power plan siting and construction needs to made consistent with demand growth, and somebody needs to plan and build enough new capacity.[2] One way to avoid supply shortages is to revert to regulated, integrated utility operations and planning. Utility planning has generally been able to avoid supply shortfalls. And if, occasionally, supplies are tight, utility regulation is reasonably well designed to avoid excessive price spikes and to ration supplies for short periods.

[1] There is a dispute about whether or not supply was actually deficient in California, or whether the whole crisis was created by manipulative suppliers. Here, we acknowledge that there was market manipulation, but that it would not have been so prevalent or have had such dramatic effects if supplies had not been at least somewhat tight (in the sense of capacity reserve margins being narrow) in the first place.

[2] Contributing to the California crisis was the way in which both California and the Pacific Northwest came to rely on power imports from each other in the late 1990s, while neither area was planning to supply the needed exports. When hydroelectric capability was reduced in 1990, and the regional economies were booming, a tight supply situation developed. Throughout, California relied upon power from the Southwest, and its increased dependence in 2000/2001 put pressure on the market in Arizona and the rest of the Southwest.

A balance between supply and demand is more difficult to achieve in a deregulated wholesale generation market. There is a tendency for a boom-and-bust cycle to develop. However, there are features of a deregulated power supply market that can avoid or at least mitigate supply shortfalls. Some planning and/or pricing mechanisms are needed to ensure the adequate construction of new power plants.

The coordinated expansion of the transmission system, in step with generation, is also necessary. The California crisis revealed transmission problems -- Northern California was unable to import enough power on Path 15 from Southern California.

The RTO may be the appropriate agency for planning and coordination. This is the view of Patrick H. Wood III, the new FERC chairman. In a striking admission that generation markets need some kind of regional (and state) planning, he said recently, “The RTO is a recognition that the power business must be planned and operated regionally...The RTO ought to be the respected body that initiates regional planning by saying, ‘In this large area we need these four projects to be built.’ Then it becomes the states’ responsibility.” (Business Week, March 4, 2002, p.30B) Wood also recognizes that price caps may be necessary to deal with price hikes; FERC responded slowly to the need for a price cap in the West in the wake of the California crisis, but finally imposed one.[3]

California's chaotic regulatory structure probably contributed to the generation deficiency; investors in new generation capacity need a favorable investment degree with regulatory and market certainty. It is reported that belatedly several new plants are coming on line, but absent the kind of foresight that FERC Chairman Wood is talking about, there is no guarantee that the cycle may not repeat itself, with a glut of power followed by a shortage later.

2. <u>ISO/RTO and Power Exchange Design</u>.

The California crisis was exacerbated by poor design of the California ISO. The problems occurred in the functioning of the California Power Exchange's day-ahead market and the ISO's real time purchases (to make up, on an emergency basis, any remaining power shortfall on the day itself). For example, when prices rose in May and June 2000, the ISO capped the price of power, but this cap did not apply to the ISO's emergency purchases in the real-time market. The result was that suppliers withdrew power from the day-ahead market, forcing the ISO to purchase more and more "emergency" power at higher prices in the real-time

[3] Partial or regional price caps can distort the market or lead to gaming. It has been noted earlier that suppliers sold power to out-of-state marketers, who then resold it in-state. Another result of California-only price caps was that power which might have been available in-state flowed out-of-state, period. There was a resulting loss of supply in California which contributing to make the market there tighter.

market.[4] This aberration peaked on July 28, 2000, when fully 28 percent of load was met on the real-time market. But even in November and December 2000, the ISO was still declaring emergencies when the generating reserve margin was apparently around 40 percent.

It is an ongoing task, under the aegis of FERC, to encourage the creation of more effective ISOs or RTOs. The West is lagging behind some other regions in this regard. Even in those regions that had a head start because they already had tight power pools, ISOs are still undergoing evolution.

3. Market power.

The California experience of market manipulation – strategic withdrawal of capacity from the market and opportunistic pricing – shows that market power is an ever-present concern in deregulated bulk power supply markets, especially when supplies are tight. Wholesale markets need to be characterized by adequate supplies, as noted earlier. They also need to have a number of effective and independent suppliers with no one supplier large enough to be able to manipulate prices, and low barriers to entry by new generators.

4. Retail versus wholesale prices.

The combination of regulated low retail prices and high and volatile wholesale prices had two unintended effects. First, it made the retail market unprofitable for third-party suppliers. After some initial skirmishes in the retail market, they withdrew and concentrated on sales in the wholesale market.[5] The lesson is that if and when states wish to make the retail market attractive to suppliers, they need to allow a differential between wholesale and retail prices sufficient to cover retail marketing costs. Looked at from the customer perspective, states need to allow customers a sufficient shopping credit to make it worthwhile for them to shop around for more efficient suppliers.

Second, the rise in wholesale prices put extreme financial pressure on the distribution utilities, which were not allowed under the California rules to pass the price increases on to their standard offer customers in the retail market. (When suppliers became afraid that the utilities would go bankrupt and not be able to pay, they withheld supplies. Their fears were justified: California's largest utility, Pacific Gas & Electric, filed for Chapter 11 bankruptcy protection from its creditors in April 2001.) Southern California Edison narrowly avoided bankruptcy. To avoid this kind of distress, it is necessary to have some kind of

[4] There were other twists. One was that the ISO could purchase power from out-of-state at higher prices than it could pay to in-state suppliers. This resulted in "laundering" of power when suppliers sold it to out-of-state marketers who then resold it into the California market. Another maneuver was for generators with market power on the export side of a bottleneck to game the ISO's congestion pricing scheme by over-scheduling capacity. The ISO would then be forced to buy decremental generation, which the same generators would offer at low prices, enhancing their net revenues.

[5] Green power was an exception, owing to a special customer credit for green power.

financial pressure valve, e.g. regulated standard offer prices need to have at least some flexibility to respond to market conditions.

5. <u>Demand-side inflexibility</u>.

The protection that retail customers initially had against wholesale price increases in California made demand less responsive than it could have been. As retail markets develop and real-time pricing becomes more economical and widespread, energy conservation and load management are likely to mitigate supply shortfalls.

6. <u>Poorly planned divestiture</u>.

In California, utilities divested most of their power plants into an imperfectly competitive market. The retail market design favored standard offer service, and the utilities were required to purchase power for standard offer service on the California Power Exchange (PX) spot market. This was a recipe for disaster. Utilities were dependent on the PX for more than half of their purchases, contrasted with less than 20% in most other divestiture situations, like that in New England, where utilities rely for the most part on bilateral, long-term purchased power agreements for their standard offer requirements.

Utility divestiture of generation assets needs to be carefully planned. The California experience in this regard can be avoided by ensuring that the wholesale generation market has adequate supplies and is potentially competitive before divestiture takes place, and that divestiture itself contributes to the competitiveness of the market (e.g., by asset sales to several separate unaffiliated generators). Also by making better arrangements for utility buy-back of power for standard offer service, including longer-term bilateral contracts.

7. <u>Natural gas dependence</u>.

High gas prices and gas pipeline bottlenecks, allegedly exacerbated by market power in the gas market, contributed to California's electricity crisis. Perhaps there is over-dependence on natural gas among electricity generators in California, who use gas to generate more than half of their power.

The potential problem of lack of fuel diversity is difficult to avoid in deregulated markets; there is a tendency for most or all generators to build gas-fired plants. The solution could be for a regional entity such as the RTO to monitor this issue and provide incentives for fuel diversity.

8. <u>Clumsy and belated state intervention.</u>

State (and federal) authorities were slow to respond to early warning signs of the California crisis. FERC finally responded appropriately by instituting region-wide price caps. However, California, through its Department of Water Resources, has now entered into long-term purchased power agreements (which its utilities had foolishly been prohibited from doing themselves) at high prices.

9. Stranded cost recovery mechanism.

The mechanism by which the stranded cost recovery charge was set in California was defective. Instead of a fixed per-kWh charge on the rates for delivery service, the charge was variable. The higher the wholesale market price, the lower the charge, and the lower the wholesale market price, the higher the charge. This variation had the result of undermining the retail supply market, because suppliers who offered customers a fixed price never knew what revenue they would be getting on a net-of-stranded cost basis.

Colorado

Colorado considered electricity restructuring in 1998 and 1999. The legislature passed, and the governed signed into law, SB 152 which established the Colorado Electric Advisory Panel to study and report on whether restructuring would be in the interests of Colorado consumers and the state as a whole. The Panel consisted of 29 representatives of the industry and its stakeholders, including consumer and business organizations.

The Panel retained Stone & Webster Management Consultants to study the situation, including the impact of restructuring on retail prices, the likelihood of utility stranded costs, and the likely effects of potential market power. Stone & Webster noted that, "Colorado has had relatively low generation costs and, therefore, fairly low retail electricity rates relative to other states." Against this background of relatively low regulated utility rates, the study's conclusions were devastating as far as the prospects for restructuring were concerned:

> -- Restructuring the electric industry in Colorado will likely lead to an increase in retail electricity rates throughout the state…
>
> -- Restructuring the electric industry in Colorado will likely lead to significant stranded benefits (negative stranded costs)…
>
> -- (Public Service Company of Colorado) controls nearly two-thirds of the utility-controlled generating capacity in the state. In the short term, it will possess market power, and be able to raise prices…[6]

In its report to the legislature and the governor in November 1999, a majority of 17 of the 29 members of the Electric Advisory Panel opposed restructuring. Among their reasons were the following:

> -- Colorado's rates are relatively low and are likely to increase with restructuring.
>
> -- Public Service Company is likely to possess market power in Colorado.
>
> -- Before implementing restructuring, a competitive wholesale market should develop in the region.
>
> -- Utility customers have a legitimate claim over "stranded benefits."
>
> -- Restructuring will expose customers to greater cost, reliability, and service risks.

[6] Stone & Webster report to Colorado Electric Advisory Panel, 1999, pages ES-1 to ES-2.

The minority of 12 panelists raised a number of general arguments in favor of restructuring. These included references to the national trend towards customer choice, and the belief that competition produces lower rates, customer choice, new investment, new products and innovation.

Whether or not the points made by the minority might have been valid in other circumstances, they were not persuasive when weighed against the Colorado-specific findings of Stone & Webster. Needless to say, the Colorado legislature did not decide to restructure the state's electric industry.

Florida

Florida was still moving in the direction of electric restructuring during 2000, and to a lesser extent 2001. In September 2000, the staff of the Florida Public Service Commission issued a report that was skeptical about restructuring, although not opposed to it. In a review of what it called "the 24 pioneer states," it found that "policy makers should lower expectations about competition substantially reducing retail rates in the short term. Moreover, few states have undertaken vigorous evaluations to see if the benefits of competition are being realized."[7]

The PSC staff is also concerned about the potential for the exercise of electric market power in Florida. "Market power in the wholesale generation market is a major concern in Florida due to two factors. First, Florida is a peninsula and has limited transmission lines between it and its neighboring states, allowing imports of only 8% of needed power...The second factor is that two incumbent utilities serve over half the load in the state. The potential for either or both of these utilities to exercise market power currently exists."[8]

A number of years ago, the Florida Energy Broker was established by the state's utilities to create a computerized system for trading hourly non-firm or "economy" electric energy. This system was extended to merchant power producers in 1995. There have also been a number of longer-term power contracts between different entities. However, according to the PSC, "wholesale sales in Florida continue to be a relatively small portion of investor-owned utilities' sales and are predominantly conducted between Florida's utilities."[9]

In December 2001, a report by the Florida Energy 2020 Study Commission recommended a further move toward a competitive *wholesale* electric market. It did not recommend retail market restructuring -- the commission chairman noted that, "Until you restructure wholesale, which will bring more players on the field, you can't have real retail restructuring."[10] The commission proposed that merchant power producers should be encouraged to build power plants in the state. Some merchant power producers have succeeded in building plants in Florida, but they face serious obstacles under Florida's stringent Power Plant Siting Act.

During the past few months, however, legislative interest in restructuring appears to have waned, and it is no longer a high priority. Governor Bush was already reported to have lost interest in restructuring during 2001 after the California

7 Florida Public Service Commission, Key Aspects of Electric Restructuring and Their Relevance for Florida's Electricity Market, September 2000.
8 Florida PSC, Market Power in a Transitioning Electric Industry, March 2001.
9 PSC, States' Electric Restructuring Activities Update, 1999.
10 The sources for this quote and other Florida news over the past year are press and trade reports reproduced in Restructuring Weekly.

crisis and the collapse of Enron. The electricity market in Florida is regarded as being in reasonably good shape, with relatively low and stable prices and adequate capacity.

During 2001, there were collaborative efforts to form a statewide RTO, GridFlorida, and the Florida Public Service Commission approved the transfer of transmission control to that entity by the state's three main electric utilities. Meanwhile, however, FERC was of course pushing for a larger regional RTO. The result has been a stalemate in which the Grid Florida endeavor has been put on hold.

Illinois

Summary

In contrast to some other states like Maine and Pennsylvania that were also among the first wave of states to embark on electric restructuring, Illinois' restructuring experience is regarded as unsuccessful so far by many of its participants, particularly customers and competitive electricity providers. This negative assessment is clearly reflected in the third Chairman's Roundtable Report issued by Illinois Commerce Commission chairman Richard Mathias in November 2001.[11]

Retail competition in Illinois is being phased-in, with large industrial and commercial customers being eligible in October 1999, other industrial and commercial customers during 2000, and residential customers in May 2002. However, after an initial period of competitive activity, the migration of customers to the competitive market and the entry of competitive electricity suppliers to that market have stalled out. One customer representative cited "a limited number of suppliers, transmission constraints, and the continuation of utility/affiliate supply purchase agreements as an indication that the 'only thing (we) are doing differently today is shifting money around to differently named players in the same affiliated group.'" (Roundtable Report, p. 6) The market in Commonwealth Edison's service territory is a partial exception -- relatively high ComEd prices and the concentration of customers in Chicago have made this market more attractive to alternative providers.

The chairman concluded that, "This Roundtable marked the first time that no participant would even argue that Illinois is experiencing robust competition or the robust development of competition." (Roundtable Report, p. 5) Although there has been no dramatic market failure like California's, the Illinois experience is disappointing and suggests the whole restructuring effort in that state may not have been worthwhile. What lessons can be learned from this experience?

It appears that a number of features of Illinois restructuring are not conducive to electric competition. First, some utilities "locked up" their "most attractive" industrial and commercial customers before the market opened in 1999. (Roundtable Report, p. 5) Second, most of the competitive providers that have entered the market are actually affiliates of incumbent utilities, and customer groups voiced concerns "that the future could subject them to the market power of incumbent utilities and their affiliates in a non-competitive environment." (Roundtable Report, p. 2) Third, Roundtable participants stated that "retail

[11] Report of Chairman's Fall 2001 Roundtable Discussions Re: Implementation of the Electric Service Customer Choice and Rate Relief Law of 1997. This report is available on the Illinois Commerce Commission's website in a section containing reports, etc., by Chairman Mathias.

competition would not develop without robust wholesale competition." (Report, p. 2) But the wholesale market is not structured to create robust competition -- transmission constraints have been an obstacle to market transactions, no RTO is yet in place to supervise the pricing of transmission services and tariffs, and there is no framework for much-needed transmission construction. There is also insufficient investment in new power plants. The result has been a tight supply situation, particularly during peak periods.

Considering the concentration of generation in the hands of utilities and their affiliates, coupled with transmission constraints, the commission had earlier concluded: "Probabilities are high that Illinois will have a number of partially isolated markets, each with a resident, unregulated, potentially monopolistic firm -- the utility's affiliate -- poised to dominate it."[12]

Relatively few competitive providers have entered the market and small customers have not found their offerings attractive. Competitive providers are frustrated with the high cost of retail customer acquisition in Illinois. For instance, start-up costs include: renting office space, buying supplies and equipment, hiring personnel, retail marketing costs, commission certification costs, and the costs of participating in proceedings before the commission. (Fall 2000 Roundtable Report, p. 38) There is a requirement for a "wet signature" before a customer can be switched, and a marketer needs to have a door-to-door sales force to sign up small customers, an expense that is not justified, considering how small the potential revenue is.

The Illinois Commerce Commission finds itself in the difficult position of having diminished --indeed "severely limited" -- jurisdictional authority to deal with the range of problems that are being encountered. The authority of FERC tends to increase when a state restructures, but the Illinois Commerce Commission chairman's experience is that FERC has been "very timid in implementing corrective initiatives." Roundtable participants complained about the "splintered nature of governmental regulatory authority," and one participant said that there was such uncertainty about the extent of the commission's authority under the new law that the commission should undertake a legal analysis of the matter. (Roundtable Report, p. 15)

Rather than take the risk of entering into contracts with independent power producers in a tight and fragmented wholesale market, Illinois customers who are eligible to shop for power have mostly stayed with utility standard offer service.

Looking ahead to January 2005, when customers are switched from current regulated standard offer rates to market-based pricing, forecasts differ. Incumbent utilities and alternative providers forecast a smooth transition, but customer representatives do not share this optimism. In the previous Roundtable, everyone

[12] Illinois Commerce Commission, Assessment of Retail and Wholesale Market Competition in the Illinois Electric Industry, April 2001, p.16.

had already agreed that "the liquidity of the Illinois *wholesale* market for electricity must increase to ensure that the Illinois *retail* electric market will be viable at the end of the mandatory transition period." (Fall 2000 Roundtable Report, p. 32, emphasis added) Some participants believe there is a risk that the wholesale market might fail, unless the supply situation improves by 2005, and there is even discussion of the possibility of a "perfect storm" like the one that hit California.

<u>Restructuring Legislation and Regulation</u>

The Electric Service Customer Choice and Rate Relief Act of 1997 (HB 362) provided for a phase-in of retail competition by size and type of customer, beginning with large industrial and commercial customers in October 1999, extending to all industrial and commercial customers by December 31, 2000, and to residential customers in May 2002. Metering services as well as generation are being opened to competition, and the commission will conduct investigations in the future to determine whether further services, such as the whole bundle of metering and billing services, should be made competitive.

Utilities continue to provide standard offer service at rates that were set at the last rate case, less reductions required in the Act. Rates will be fixed during the transition period, which ends on January 1, 2005. Affiliate suppliers may use the name and logo of the utility, but are prohibited from joint marketing.

Competitive suppliers have to be certified by the commission, and must provide a performance bond and proof of technical, managerial and financial capability. A "wet signature" is required on a contract between the customer and the competitive supplier, who must notify the utility. The customer may get one bill (from the generation supplier), or two bills -- one for generation and one for distribution service.

Those customers who choose a competitive provider must pay the utility a competitive transition charge to enable the utility to recoup stranded costs. The competitive transition charge continues to December 31, 2006. The period may be extended to December 31, 2008, except in the case of ComEd.

The Act applies primarily to investor-owned utilities. Electric cooperatives and municipal utilities are not required to allow their customers to switch suppliers, but they may do so if they wish.

The Act did not require divestiture or structural separation of competitive activities from regulated utility activities. However, after January 1, 2003, the commission may require separation, and this step is under consideration.

<u>Electricity Market Profile</u>

There are six major utilities in Illinois, of which Commonwealth Edison is the largest. The electric grid is connected with neighboring Midwestern states. The utilities have been members of the Mid-American Interconnected Network (MAIN) reliability council, and have been split over whether to join the Midwest ISO (MISO) or the Alliance RTO. Describing the Midwest ISO as "in disarray," the commission chairman believes that if the governance of the transmission system is bifurcated, it would "likely lead to a dysfunctional system."[13] In December 2001, FERC approved MISO as the first official RTO in the country, rejected the Alliance RTO, and urged utilities to consolidate the two RTOs into one single Midwest RTO.[14]

The electricity market is reported to be transmission-constrained, and supplies are tight at certain times. However, a certain amount of plant construction activity is taking place, and there are plans to build more plants in the future. Recently, the chairman has taken an equivocal position on the adequacy of generation and transmission capacity in Illinois, perhaps because he is trying to contrast Illinois with California: "Most commentators agree that Illinois currently has adequate base load supply and peak load supply is likely to be adequate as well. However, there is concern about adequate supply in future years." [15]

Earlier, the commission had been more outspoken. In describing its investigation of wholesale market conditions in 2000, it said "there is every reason to believe that retail prices, passed through from the concentrated wholesale markets, will be higher than they would be with a market structure that is supporting actual wholesale competition. . . . Given the incentives in the present market structure of affiliates and holding companies, there is little evidence that this situation will change in the near future." (Assuming there are no changes), "the preliminary evidence indicates that there are reasons to believe that retail prices may increase dramatically by the time the general rate freeze expires in 2005." The commission's evidence for this dire assessment included the fact that "the overwhelming majority of power is still coming from incumbent utilities;" limited inroads of independent power producers; and "concern regarding the ability of the Illinois transmission system to support a competitive wholesale market between and within utility territories."[16]

Restructuring and Market Activity to Date

Although not required to do so, most of the state's six major utilities have in fact transferred or divested generation assets. Meanwhile, with two exceptions, Illinois

[13] Illinois Commerce Commission, Can a California Energy Debacle Occur in Illinois? An Outline of Some Differences and Similarities Between California and Illinois, February 2001, p.6.
[14] Illinois Commerce Commission, 2001 Annual Report on Electricity, Gas, Water and Sewer Utilities, January 2002, p. 63.
[15] Illinois Commerce Commission, Can a California Energy Debacle Occur in Illinois? An Outline of Some Differences and Similarities Between California and Illinois, February 2001, p. 5.
[16] Illinois Commerce Commission, Assessment of Retail and Wholesale Market Competition in the Illinois Electric Industry, April 2001, p.iii.

utilities have transferred their generation facilities to affiliated companies.[17] An important exception is ComEd, which sold its coal- and gas-fired plants to an unaffiliated company, which is an affiliate of Southern California Edison. ComEd has a purchased power agreement with the buyer that gives it the right to purchase substantial portions of the output of these facilities for a number of years.

The data on customer switching to competitive suppliers in Illinois is confusing for several reasons, including differences between one utility service area and the next, and the phase-in of eligibility. According to the commission's latest Annual Report, approximately 20,000 customers have switched to an alternative provider, or to a lower-cost generation service offered by their utilities -- this is the PPO described below. Of these, about 18,000 or about 90% are in the Commonwealth Edison service territory. In five utility service areas there has been no switching at all. At least 673,000 customers were eligible to choose other suppliers; only 3% have done so.

Even though the proportion of load that has switched is much higher, because larger customers are more likely to switch, this experience is disappointing, especially when one considers that much of the switching was merely to the utility PPO option or to a utility affiliates. PPO is a rather complex option available to large customers during the transition period. A purchase power option (PPO) allows them to switch out of bundled utility service, but still obtain power from the distribution utility at an *estimated* market price set for one year. The customer can assign this right to a power marketer, which will only make sense if the market price has fallen below the PPO price. Since market prices have tended to be higher than PPO estimated prices, the result has been that the utility effectively still remains the provider.

At the end of 2001, there were fourteen alternative retail electric suppliers certified by the commission, of which five had been added during 2001. Some of the suppliers operate only in certain areas, however, and in many utility service areas there is limited availability of suppliers.[18]

In April of each year, the commission submits an annual report to the legislature and the governor, *An Assessment of Retail and Wholesale Market Competition in the Illinois Electric Industry*. The latest available report is, of course, somewhat dated because if is for 2000. However, it reveals the same picture as we have seen in 2001. By the end of 2000, 22% of eligible customers had switched in the ComEd service territory, approximately 10-15% in three other service territories, and few if any customers in the remaining five investor-owned utility service territories. "Most suppliers continue to concentrate their efforts in the ComEd service territory." Many of the customers who switched to delivery-only service

[17] Illinois Commerce Commission, Can a California Energy Debacle Occur in Illinois? An Outline of Some Differences and Similarities Between California and Illinois, February 2001, pages 1-2.
[18] Information on switching and alternative providers is from Illinois Commerce Commission, 2001 Annual Report on Electricity, Gas, Water and Sewer Utilities, January 2002, p. 64.

still obtained supplies under other arrangements with the utilities or their affiliates. The 2000 report concluded that "(d)elivery services' customers relatively high rate of use of utility-generated power may provide an indication that the wholesale market is not presently capable of producing a sufficient supply of low-cost power to support a retail market."

Why has customer switching been so uneven? Is there anything we can learn from the high level of switching in the ComEd service territory in Chicago? It is not due, apparently, to the transmission situation: Chicago is a load pocket, which implies that it could be difficult for competitive providers to bring in power from out-of-town. The likely factors could be ComEd's high regulated rates, ComEd's divestiture of generation to an unaffiliated company -- which took the utility out of the generation business -- and/or Chicago's high concentration of customers.

Maine

Summary

Maine embarked early and vigorously on its electricity restructuring project. It did this in step with the general move to restructuring in New England, with the objective of ending the high-price utility monopoly regime. New England was already a relatively high-cost region, because of its dependence on oil and its distance from sources of low-cost fuels such as natural gas and coal. The over-building of nuclear power plants in the 1970s and 1980s made the situation worse and provided much of the political momentum for restructuring.

New England states could depend on having the bulk power system coordinated by a tight power pool, NEPOOL, which provided the basis for an ISO in 1997. ISO New England administers the wholesale markets and controls the system for purposes of ensuring reliability. Maine's restructuring legislation states that in order for retail competition to function effectively, ISO governance must be "fully independent of influence by market participants." The Commission does not believe that independence has yet been satisfactorily achieved. (Annual Report, p. 20) And despite the modification of NEPOOL protocols, and the existence of several vigorous competitive generators, there have been continuing concerns over market power abuses. For example, although a number of independent power producers and merchant generators have succeeded in entering the New England market, they have complained that the interconnection rules are onerous and can result in significant project delays. In July 2001, FERC proposed that ISO-New England, together with New York and the PJM Interconnection, be part of a larger Northeastern RTO. It is not clear whether this combination will take place, or whether alternative means will be found to foster the interchange of power between these regions. In February 2002, ISO New England and the New York ISO announced plans to explore the benefits of merging the two power pools. They committed to completing their evaluation by the end of June 2002.

Certain features of Maine's restructuring effort are noteworthy. First, after the restructuring act was passed in 1997, the Maine Public Utilities Commission used rulemaking procedures and stakeholder groups to develop the rules and procedures during 1998 and 1999 that would govern distribution utilities and competitive electricity providers. The legislature decided that utility divestiture of generation assets was desirable, if a truly competitive power market was to be created. The Commission developed unbundled rates for distribution service and approved the sale of the utilities' generation assets. "Because of the comprehensive preparation, entities operating in Maine avoided some of the technical and procedural problems encountered in many other states."[19] The Commission also conducted a consumer education campaign.

A result of divestiture was that standard offer would have to be provided in some manner from the now-separated generation market. Maine decided that standard offer franchises should be broken up into manageable areas and put out to bid by suppliers for successive periods of two years. This procedure has not been without its difficulties: in some cases all bids had to be rejected because the prices seemed out of line. However, contracts were eventually entered into and the Maine PUC appears to be reasonably satisfied with them.

On the other hand, direct access has not yet taken hold in the residential and small commercial market. Less than one percent of these customers have switched to competitive suppliers in the two largest utility service territories. Rather than entering through the front door, competitive suppliers have entered through the side door by competing to provide standard offer service, which effectively covers the entire small customer market, and most medium-sized customers too.

Most large customers, however, have switched to competitive suppliers. A large customer is defined as one with a load of 400 or 500 kW, depending on the service area, and includes paper manufacturers (the largest users of electricity in the state) and also the largest colleges, hospitals and supermarkets.

After two years of restructuring, the Commission believes that Maine has accomplished "the most successful overall transition to competition in the nation." (Annual Report, p. 29)

Restructuring Legislation and Regulation

On May 29, 1997, L.D.1804, *An Act to Restructure the State's Electric Industry*, was signed into law by the Governor. It provided that all retail electric customers would be able to choose their electricity supplier beginning March 1, 2000. It directed the Maine Public Utilities Commission to conduct rulemaking procedures on several issues that would have to be resolved in opening up the retail market to competition.

The Act requires that utilities divest their generation assets (except for nuclear generation) and their purchased power agreements, and that the Commission conduct a rulemaking on the bidding procedures for these sales. Standard offer service would be available to all customers. Franchises to supply electricity for standard offer service must be put out to competitive bid, and at least three providers should, if possible, be chosen. A docket was opened to implement this

[19] Maine Public Utilities Commission, Annual Report on Electric Restructuring, December 31, 2001. This report, which the commission is required to submit to the legislature at the end of each year, is a valuable source of information on restructuring developments in Maine. It is available on the Commission's website.

process in terms of Chapter 301 of the Act, which contains the terms for standard offer service and the procedure for selecting bidders.

Other rulemakings covered such issues as licensing requirements -- including a showing of technical and financial capability and providing a surety bond or letter of credit -- and uniform information disclosure requirements for competitive electricity providers. Rules were promulgated to implement a resource portfolio standard contained in the Act, and to provide for net energy billing, load profiling procedures and metering, and protocols for transactions between utilities and providers. Utility stranded cost recovery is provided for.

The state now has significantly less involvement in utility plant siting and planning. Certificates of public convenience and necessity, with their traditional showing of need, are no longer required.

The Electricity Market in Maine and the Rest of New England

Maine, like the rest of New England, has long suffered from high electricity prices. Generation depended on oil, or on coal or gas, which were expensive when transportation costs were taken into account. Nuclear power was seen as the technology that would overcome the disadvantage of high fuel costs. The escalation of nuclear power costs, and the problem of excess capacity that resulted when demand growth slowed in the 1970s and remained relatively constant in the 1980s, resulted in high retail prices. These, together with controversy over nuclear power as a technology, led to a consumer backlash against the utilities and provided a backdrop to the movement to restructure the electricity industry.

Apart from the isolated northern part of the state, Maine is closely integrated into the New England electric grid, which was operated by NEPOOL, and since 1997, operated by ISO New England. ISO New England also administers the wholesale markets that were implemented in May 1999 under a contract with the NEPOOL Participants who continue to own the generation and transmission assets in New England. Even before the push towards ISOs and RTOs, NEPOOL was one of the country's few "tight" power pools. This meant that the New England power system was operated and planned on an integrated basis. The system was centrally dispatched, and the integration of new power plants and transmission facilities were coordinated by NEPOOL to ensure that loads and resources were matched.

The movement towards state restructuring in New England has depended on the development of NEPOOL from a tight power pool to an ISO. Current ISO New England market rules and tariffs contain provisions for tracking and accounting for supplies not only among utilities and between utilities and independent power producers, but also from IPPs to retail customers under direct access arrangements.

ISO-New England has experience a fair number of market disruptions and price spikes, but has not suffered the extreme malfunctions such as those that afflicted California in 2000 and early 2001. However, the Maine PUC acknowledges in its Annual Report that, "The development of regional market rules has been fraught with discord, but there appears to be some progress toward an efficient market." There have been continuing complaints about the exercise of market power by suppliers in the New England market. First, independent power producers believed that the transmission interconnection arrangements discriminate against them and favor incumbent utilities.

Second, prices in the wholesale market appear to be higher than can be justified on the basis of power plant costs. There is the perception that the two or three large companies that between them account for the majority of generating capacity in the market are able to manipulated prices. In 1999, approximately 12% of the energy transactions were sold through the spot market, with most transactions still sold through bilateral contracts. In 2000, spot market energy transactions increased to about 20% of all sales. There is no way of knowing the extent to which bilateral contracts might, as a result of market power, be higher-priced than they would be under a more competitive market. An analysis of the New England market Commissioned by ISO New England and the Massachusetts Attorney General after the price increases during 2000 found that the New England electricity market was at least as efficient as PJM's and more efficient than California's, with market-based prices 4-12% above costs. Continued monitoring of the market was necessary, however, the report concluded.

In the initial market design, ISO New England administered a spot market for Installed Capability (ICAP) as well as a spot energy market. The existence of an ICAP market can be justified as way to reward suppliers for keeping generating capacity available for purposes of system reliability. However, it was felt by many participants, including the Maine Commission, that prices in that market have far too high at times. Recall that the spot energy market already clears at the highest bid accepted, which is higher than operating costs for all intra-marginal bidders, so there is the danger of duplicative rewards for capacity. After serious abuses occurred in the ICAP spot market in early 2000, the spot market was eliminated and replaced with a price-cap administered market that levies a deficiency charge, on a monthly basis, on any market participants who fail to secure sufficient ICAP resources in the bilateral markets. Additional changes are being considered, however, with the increased supply of new generation in 2001, there have been sharp reductions in ICAP prices.

Despite the problems encountered in the operation of the New England power market, a number of developers have entered the New England market. According to the Maine Office of Public Advocate, 1,500 MW of new capacity is currently being added in Maine alone. Almost all of the capacity being added in Maine and the rest of New England is natural gas-fired, which has been made possible because of the construction of new pipeline capacity o bring gas in from Canada to supplement U.S. sources of gas.

Corporate Restructuring Activities to Date

Utility generation asset sales were generally at prices much higher than book value, and were regarded as successful. The result was that electricity companies are primarily engaged in either the wires business or power supply, ending the era in which utility companies typically provided both types of service.

Customer bills were unbundled in January 1999. Customers receive one consolidated bill -- from the distribution utility, which calculates consumption and issues a bill for energy supplied as well as for distribution service.

Utility distribution companies may have marketing affiliates, which are subject to various restrictions. They cannot advertise jointly with the utility, and if they must compensate the utility if they use the utility name and logo.

Municipal and cooperative utilities are restricted to selling electricity in their own service territories.

Standard Offer Service

The Commission is required under the Act to attempt to have at least three competitive providers of standard offer service in each utility service territory. Bidders may bid on all or part of the load of each designated group of customers. The first round of bidding took place in 1999, to provide service for the initial period commencing on March 1, 2000. Some winning bids were accepted by the Commission for service to residential and small commercial customers of the state's largest utility, Central Maine Power (CMP). But other winning bids were rejected and the bid process was terminated. The Commission found that some bids did not conform to the bidding procedures and others were simply too high-priced. The utilities were ordered to procure power for the groups of customers involved.

During 2000, the Commission conducted proceedings to amend the standard offer procedures to correct certain problems that had emerged during the first bid process and to resolve certain opt-out issues. At the end of 2000 a second round of bidding took place for providers who would begin service in March 2001. Again, some winning bids were accepted (to provide service for a three-year period) and others were rejected. There had been price spikes in the wholesale market and the bid prices were unacceptably high. The Commission, predicting (correctly) that prices would drop, arranged again for utility purchases on the wholesale market.

In planning for standard offer service for the period beginning March 1, 2002, the Commission hedged its bets by requesting bids, and, in parallel, directing the utilities to solicit bids for power on the wholesale market. In the end, the Commission awarded standard offer service for most residential and small business customers for a three-year period to a company which would acquire the utilities' purchased power entitlements, a creative solution. (Annual Report, p. 15)

Standard offer providers have to take on "load risk," namely the uncertainty about how many customers will take standard offer during the contract period, which all depends on the relative prices of standard offer (set at the beginning of the period) and market prices (which change during the period according to market conditions). This risk tends to result in bids that are somewhat above-market, which paradoxically causes more migration. The way in which standard offer tracks the market, but with a time-lag and a premium above market, may explain why there has been more migration to the competitive market in Maine and why it has been relatively steady compared with most or all other states. Simply put, standard offer is not a bargain for customers compared with prices they can get on the open market. Transaction costs for small customers, coupled with the fact the potential gains are small for those customers, probably explains why they have not migrated along with larger customers.

Marketing affiliates of distribution utilities may bid to provide standard offer service in the service territory of their affiliate utility, but they may provide no more than 20% of the affiliate utility's load, unless required to do so by the Commission.

The Commission says it has learned several lessons from its intensive experience with standard offer service bidding over the past two years (Annual Report, p. 14). Suppliers, the Commission has found, are *risk averse*. For example, they don't like to leave their bids open for long periods of time. Initially, bids were required to be open for two months, and even when the period was reduced to two weeks, market volatility made the bidders reluctant to keep bids open for longer than 24 hours. Second, suppliers can be creative, e.g., including contingencies or indexed or formula bids. In response, the Commission needs to be flexible in its requirements, even though it makes it more difficult to compare bids with each other.

A third lesson learned by the Commission is one that has heightened relevance in light of the collapse of Enron -- the need for contractual protections and financial security. In Maine, there was a contract dispute between a standard offer provider and its wholesale supplier. Because the standard offer price was below market, a switch back to the market at that point would expose customers to price increases totaling as much as $150 million. However, the provider's performance bond was for only $33 million. Fortunately, with Commission facilitation, the contract dispute was settled.

During 2004, the Commission will conduct an investigation into whether standard offer service should be continued after March 1, 2005. Meanwhile, the

Commission is not planning any changes in the standard offer rules, but will continue to monitor the situation. The Commission accepts the fact that direct access is slow in coming for residential and small business customers, partly as a result of the success of standard offer service. It believes the market may grow gradually, as suppliers extend their reach from larger to medium and then smaller customers. (Annual Report, p. 16)

Direct Access

Customers can switch to a competitive provider at any time. They can also return to standard offer at any time, but there are certain penalties and restrictions in this case.

The attractiveness of direct access to retail customers in Maine -- and to competitive electricity providers has thus far been directly related to the size of the customer. While the state's three investor-owned utilities have somewhat different situations, the figures for CMP tell the story -- 88% of large customer load, 42% of medium-sized customer load, and less than 1% of residential and small commercial customer load was served by competitive providers, as of December 1, 2001. Statewide, 44% percent of load has migrated to the competitive market.

The percentages vary considerably by time period. Most of the growth in supplier switching took place after September 2000, notwithstanding the spikes in wholesale market prices. For medium-sized customers, migration accelerated during 2001. Standard offer service prices locked in some of the higher prices from late-2000, while wholesale market prices dropped during 2001, creating a favorable opportunity for competitive providers. Presumably, if wholesale prices drop further and stay down, switching will continue, but again, it will all depend on relative standard offer and market prices.

Changes in Prices

It is difficult to summarize the changes in prices paid by customers since March 2000, when direct access was introduced. The factors that have influenced prices have included some utility-specific factors, and the fluctuations in wholesale market and standard offer prices. Transmission and distribution rates (including stranded cost charges) dropped initially, and have remained roughly stable during the past two years.

For standard offer customers of Central Maine Power, the state's largest utility, all-in prices are still lower than they were in March 2000. For some other customers, prices rose in 2001 and are falling back to around March 2000 levels in March 2002. The Commission does not know the prices paid by large customers on the open market, but believes that customers "generally retained the benefits of lower prices." (Annual Report, p. 8)

The overall effect of having a reasonably stable regulatory environment in Maine -- the 1997 legislation has remained in place virtually unchanged -- may be to provide suppliers and customers with a good framework within which they can make consistent and complementary decisions.

Metering and Billing Competition

The Act provided that metering and billing services, like generation, would be open to competition. The deadline was set for March 1, 2003. However, the Act has been amended to remove the deadline and leave the matter within the discretion of the Commission.

Renewables Portfolio Standard

The legislation includes a requirement that suppliers provide 30% of their supply from renewable resources. "Eligible" resources include traditional renewables such as wood biomass and hydro, as well as trash and efficient cogeneration using mostly fossil fuels, but in some cases new sources such as tires or sludge. According to the Commission (Annual Report, p. 10), in 2000 at least 38% of generation sold in Maine was generated by eligible fuels. Of that amount, about 60% was from traditional renewables (hydro and biomass). Municipal solid waste accounted for 23%.

"Green" products have not caught on in Maine. One provider offered a green product at a price premium of approximation one cent per kWh, but consumers showed little interest and the product was dropped. One aggregator received some interest from consumers but could not find supplies at a reasonable price. (Annual Report, p. 11)

Montana

The Electric Utility Industry Restructuring and Customer Choice Act of 1997 (SB 390) set a schedule for a transition to retail competition by July 2002. However, Montana shared the concerns of other western states over regional electricity price increases starting in 2000. In December 2000, finding that there would not be workable competition in the Montana wholesale electric market for the foreseeable future, the commission exercised the discretion given to it under SB 390 to extend the transition period by two years, to July 2004. And in 2001, the Montana legislature, in HB 474, extended the transition period even further, to July 2007.

There was a lot at stake. Under SB 390, the state's principal investor-owned electric utility, Montana Power Company (MPC), is required to offer default service -- which is the service available to residential and small business customers who do not choose an alternative provider or wish to return to utility service -- at cost during the transition period. A premature switch to market pricing at a time when the wholesale market was not yet workably competitive could have resulted in much higher prices.

Meanwhile, MPC had sold its generation assets to PPL Montana in December 1999. Further, MPC, which is focusing on the telecommunication business, is selling its transmission and distribution assets to NorthWestern Corporation, a company that operates electric utilities in For purposes of this description, we will refer to the transmission and distribution company as "MPC."

The thinness of the Montana electricity market made it obvious that MPC would continue to obtain the power it needed as default service provider from PPL Montana. At what price would MPC buy back the power? MPC narrowly escaped entering into a deal with PPL Montana in 2001 that would have fixed the price at 4 cents/kWh, a price that did not seem so unreasonable at the time but seemed too high to the commission and others. Hindsight has confirmed that the commission was quite right. Commissioner Bob Rowe said recently, "I commend the commission for taking many strong steps including...rejecting a $.04 supply price last spring that subsequent events demonstrated would have been substantially out of market."[20]

A threshold issue in MPC's generation asset sale was whether the state or the FERC would have jurisdiction over the generation assets and the purchased power agreement. Normally, one would assume that the assets and the buy-back

[20] Montana Public Service Commission, Final Order in the Matter of the Application of Montana Power Company for Approval of...Transition Plan...(and) Sale to NorthWestern Corporation, Concurring opinion of Commissioner Rowe, January 31, 2002

agreement would now come under FERC jurisdiction. However, there were certain legal issues specific to Montana law that we will not explore. Suffice it to say that the determination was made by the state commission that under the particular provisions of Montana law, the generation assets could *not* be transferred out from under state jurisdiction. As the commission chairman is reported as saying, “Today the commission stepped up and took the leadership role in the electricity price crisis.” And commissioner Bob Rowe said, “The commission cannot repeal energy supply competition, but we are attempting to soften the price shock on the road to competition.” (Montana PSC press release, March 28, 2001)

The commission ruled that MPC had an ongoing obligation to provide default service at cost during the transition period, and it had sold the assets to PPL Montana subject to that obligation. The assets remained in MPC’s regulated rate base, despite the transfer, the commission found. Accordingly, the PPA would be a full-requirements contract at a cost-based rate during the extended period to July 2007. Only after the commission had approved MPC’s transition plan, would its jurisdiction end. At that point, the purchase would be in the wholesale market which is deregulated, or at least is not regulated by the Montana commission. Meanwhile, FERC too seems to have given precedence to PPL Montana’s contractual obligation to supply power to MPC at cost.[21]

[21] The legal issues are described in a Montana PSC staff memorandum dated May 30, 2001, Montana Public Service Commission’s Regulation of MPC’s Electricity Supply Obligation Under SB 390 (1997) and after HB 474 (2001), May 30, 2001.

Nevada

Summary

In 1997, Nevada committed to restructuring its electric industry and allowing retail choice by January 1, 2000. However, in the ensuing years, Nevada initially postponed implementation and then repealed its restructuring laws in the spring of 2001. Issues internal to Nevada, including increasing rates and reliability concerns, as well as external issues, primarily the problems that California was experiencing with the implementation of its restructuring process, combined to persuade the legislature to abandon Nevada's restructuring plan before it was fully implemented.

Electric System

The Nevada system is comprised of two vertically integrated utilities -- Sierra Pacific Power in the north (peak load of 1563 MW) and Nevada Power in the south (peak load of 4412 MW). In 1999, Nevada Power was merged with Sierra Pacific Power and its parent company Sierra Resources. The two systems are physically separate, but both have interconnections with California and other states. Nevada also has a few municipal and rural cooperative utilities, as well as the Colorado River Authority Project

Restructuring history

As with many states, Nevada has evaluated restructuring issues through a combination of legislation and utility commission proceedings. In 1997, the NV PUC (then known as the Public Service Commission of Nevada) issued a report entitled "The Structure of Nevada's Electric Industry" which discussed the many options available for restructuring the electric utility industry in Nevada. Also in 1997, the Nevada Legislature passed AB 366, which authorized retail competition for Nevada consumers starting on January 1, 2000, unless the Nevada PUC determines that a later date is necessary to "protect the public interest". That legislation also required the restructuring of the Public Service Commission into the Public Utilities Commission. This involved a reorganization of the agency to better prepare for retail electric competition, reduced the number of commissioner from five to three, and transferred jurisdiction for some transportation related issues to a newly created Transportation Services Authority. AB 366 gave the NV PUC a wide-range of discretion to establish the services that can be supplied on a competitive basis, the regions in which those services can be provided, and the dates upon which service should commence.

In 1999, the Legislature made significant modifications to the timetable established under AB 366 by enacting SB 438. The rate caps set in 1997 were removed and new caps implemented that would continue until 3/1/03. Retail choice was delayed until March 1, 2000, unless the Governor, in consultation with the PUC, decided that further delay was necessary to "protect the public interest". Alternative providers, after 7/1/01, could offer competitive services if they agreed to cover at least 10 percent of the load of the existing provider, provided service to more than one class of customers, and provided at least a 5 percent discount in price. SB 438 also required that existing power contracts be honored and that the Nevada PUC provide each utility with an opportunity to recover the costs associated with those contracts.

Concurrent with the actions of the Nevada Legislature, the Nevada PUC was evaluating a proposed merger of Sierra Pacific and Nevada Power. In an Order issued in January 1999, the PUC approved the merger, with a requirement that the new merged company divest itself of its generation assets. Although the Legislation permitted the sale of generation assets to an affiliate, such sales would have been subject to an administrative procedure to allow the recovery of stranded costs. In addition, the incumbent utilities would have been required to comply with operational restrictions designed to ensure functional separation of the affiliates. These restrictions, burdensome in the view of the incumbent utilities, would not be applicable to competitive providers who were only seeking to serve loads. Sierra Pacific and Nevada Power decided their best course was to auction off their generation assets to independent third parties. Since the Legislature had consistently required the incumbent utilities to be the default providers for any customers who did not select an alternate provider, the incumbent utilities faced the difficult task of having to sell off there generation assets and then enter into power contracts to secure adequate resources for an uncertain amount of load.

In July 2000, the NV PUC approved a Global Settlement that had been proposed by a diverse group of Nevada stakeholders, including the incumbent utilities, the Commission Staff, Bureau of Consumer Protection, the Nevada Resort Association and many individual large customers. The Settlement resolved a number of outstanding lawsuits related to when and how the incumbent utilities could recover deferred costs. SB 438 had eliminated deferred energy accounting, but allowed the utilities to file for "one more" deferred accounting order. The lawsuits were mostly about how to interpret SB 438. The Settlement ended collections from the deferred accounting orders, but allowed increases to the fuel and purchase power components of each utility's rates on a rolled in basis. The Settlement also provided for a revised timetable for retail open access. The utilities largest customers would be eligible to select alternative providers starting on 11/1/00. Two other customer groups would be eligible for choice staring on 4/1/01 and 6/1/01 respectively, with all remaining customers eligible no later than 12/31/01.

However, before the Global Settlement could be fully implemented, the Legislature enacted AB 369 in April 2001. This measure repealed all previous restructuring legislation (including AB 366 and SB 438). In large part a response to the extreme distress experienced by California in late 2000 and early 2001, AB

369 prohibited the sale of any generation assets by the incumbent utilities prior to July 1, 2003. After July 1, 2003, any propose sales would have to be approved by the NV PUC with a specific finding that the sale was in the public interest. The NV PUC would be able to condition the sale upon such terms or modifications that it deemed appropriate. Any existing PUC Orders approving sales of generation assets prior to July 1, 2003 were vacated by the legislation. In addition, the legislation required incumbent utilities to utilize deferred energy accounting beginning 3/1/01 for fuel and purchased power. The deferred accounts would need to be cleared at the end of each twelve-month period though a proceeding of the NV PUC; that proceeding would include a specific prudence finding for the fuel and purchased power costs. Under Nevada law, the PUC has no discretion to allow even a partial recovery of any cost that is determined to have been imprudently incurred.

Also in 2001, AB 661 was enacted. One of the significant features of this legislation is that it allows commercial, industrial, or governmental customers with loads of 1 MW or greater to enter into agreements with alternative providers. There are several conditions to such arrangements. First, an exiting customer must provide 180 days notice and have its request approved by the NV PUC. If the customer is in a densely populated county, it must arrange to purchase 110 percent of its energy needs and make the extra ten percent available to the incumbent utility for its remaining customers. The NV PUC will determine if the ten percent extra energy is in the best interests of the remaining customers; if so, the incumbent utility must accept the energy and provide it to its remaining customers, with a preference for residential customers with small loads. The exiting customer may return to the incumbent utility with reasonable notice and a requirement that any incremental costs to serve the returning customer will be paid by that customer. Prior to July 1, 2003, the aggregate purchases of exiting customers cannot exceed one half of the incumbent utility's purchased power requirements.

AB 661 also restored the NV PUC to five members, after July 1, 2003. It created a Fund for Energy Assistance and Conservation that would be funded by a Universal Energy Charge of 3.30 mills for each therm of natural gas sold at retail and 0.39 mills for each kWh of electricity sold at retail (public utilities, rural cooperatives, and general improvement districts, as well as electrolytic manufacturing processes were exempt form the charges) and imposed a maximum quarterly cap of $25,000 for a single customer or customers under common ownership and control. Seventy-five percent of the money in the fund would be designated for low-income energy assistance through he Welfare Division and twenty-five percent of the money in the funds would go towards energy conservation, weatherization, and energy efficiency improvements through the Housing Division. Furthermore, a Trust Fund for Renewable Energy and Conservation was created, administered by a nine-member Task Force (six appointed by the Legislature, two by the Governor, and one by the Consumer advocate). Through separate legislation, Nevada utilities are required to obtain fifteen percent of their wholesale power form renewable resources by 2013. AB 661 also expanded net metering opportunities.

Special features

Under AB 366 (1997)

- Residential rates frozen at 7/1/97 levels, but PUC can raise them under certain circumstances.
- Vertically integrated utilities can provide competitive services only through an affiliate.
- PUC must monitor the market place and prevent activities inconsistent with the bill.
- Disco must provide all non-competitive services unless PUC designates another entity.
- Bill establishes mechanism to calculate and recover stranded costs of vertically integrated utilities
- PUC must implement regulations to prevent slamming, provide information disclosure, provide consumer education, and establish an increasing RPS
- PUC must develop forecasts of electricity usage, establish equitable obligations for customers and suppliers to ensure adequate capacity, and make quarterly reports to the Legislature on developments in the electric industry,
- A Bureau of Consumer Protection is created and the Nevada Public Services Commission is re-named and restructured into the Nevada PUC.

Under AB 369 and 661(2001)

- All prior restructuring legislation is repealed
- No generation assets can be sold prior to July 1, 2003 and must be approved by the NV PUC and the Consumer Advocate is a party.
- Deferred energy accenting is re-instated
- Rates frozen at April 1, 2001 levels until all deferred accounts are cleared and a general rate application, filed by October 1, 2001, is approved.
- Large customers (>1MW) may apply to exit the incumbent utility, subject to NV PUC approval and must purchase 110% of their annual energy consumption to assist remaining customers.
- Low income assistance and energy conservation fund established through a system benefits charge on gas and electric utilities
- Renewable portfolio requirement of 15% by 2013.

Current status

Nevada Power is just completing its application for clearing its deferred energy account, currently over $900 million. Sierra Pacific has filed its application for its deferred energy account in the amount of approximately $350 million. In January 2002, Barrick Goldstrike Mines became the first large customer to file for permission to leave Sierra Pacific Power. In March 2002, Rouse Fashion Show Management, Coast Hotels and Casinos, Station Casinos, and Gordon Gaming all filed for permission to leave Nevada Power.

New Mexico

The Electric Utility Industry Restructuring Act of 1999 set in motion the opening-up of the state's electric market to direct retail access beginning in 2001, and with all customers to have access by January 2002. As provided in the Act, the New Mexico Public Regulation Commission (PRC) has conducted various dockets to implement restructuring.

Beginning in August 2000, in response to the California electricity crisis, a number of stakeholders started pressing for a delay in implementing retail competition. They included the State Attorney General, who has the authority to participate in PRC proceedings on behalf of ratepayers, PRC staff, some large energy users, and electric cooperatives. These stakeholders expressed concerns about the inadequacy of generating capacity in the Southwest to ensure a smooth transition to competition, and an irrevocable loss of jurisdiction by the PRC over retail electric power supply. The PRC has this to say:

> Similar to California's restructuring law, New Mexico's Restructuring Act requires utilities to sell or transfer all of their generation assets. Once this asset separation is completed, the state will lose jurisdiction over the generation assets. Utilities will no longer own generation. All power sold to consumers will be priced at market. asset separation is the most significant act of restructuring and represents a point of no return for states moving towards deregulation. When generation assets are separated from the utility, neither the Commission nor the legislature can reverse this act. Prior asset separation, only the legislature can delay restructuring or modify the Restructuring Act, and the Commission's approval of utilities' requests to separate generation assets from the regulated utility would foreclose any such legislative opportunities.[22]

Under the Act, asset separation was scheduled to take place in August 2001, and the 2001 legislative session passed SB 266, signed into law by the governor on March 8, 2001, delaying the implementation of electric restructuring by five years to 2007. Under SB 266, utilities must sell or transfer their generation assets and file transition plans during 2005.

SB 266 also included incentives for the building of new generating capacity in the state, to avoid supply inadequacy. Provisions included permission for utilities to build or acquire generation assets for the wholesale market, provided their cost is not included in retail rates. However, the utility still has an obligation to serve during the delay period, and if a new, unregulated plant is used to serve retail customers, it will be priced at cost, not at market.

[22] New Mexico Public Regulation Commission, 2001 Annual Report and Electric Restructuring Report, December 1, 2001, p. 8.

On January 8, 2002, the PRC adopted an interim energy policy for New Mexico, which would guide the energy sector during the period up until restructuring. The commission took a negative view of the benefits of restructuring, finding that, "Very little of those predicted benefits have materialized anywhere in the nation." Some of the points in the commission's 24-point policy statement are as follows:

> -- A thorough risk benefit analysis of competition, as well as a review of the lessons learned from other states, should be performed prior to opening up New Mexico markets.
>
> -- New Mexico utilities should be required to support more diverse generation sources, including renewable energy, as a means to hedge against market and fuel price spikes.
>
> -- Rules to promote reliability should be developed and adopted.
>
> -- A thorough analysis of New Mexico's transmission system should be performed to determine under-capacity and constraints on a regional basis as well as within the state of New Mexico.
>
> -- The (commission) should commence an investigation into areas and services in the electric industry which through opening to competition could provide greater benefit or savings to consumers.
>
> -- Vigilant oversight of utilities' obligations to provide safe, adequate, and reliable service at just, reasonable, and non-discriminatory prices should be continued.[23]

[23] New Mexico Public Regulation Commission, *In the Matter of the Development and Adoption of an Electric Energy Policy for New Mexico*, Utility Case No. 3668, Resolution dated January 8, 2002.

Ohio

Summary

In Ohio's electric restructuring, all retail customers have been permitted to choose competitive providers since January 1, 2001. "Aggregation is the true success story," according to Public Utilities Commission of Ohio chairman Alan R. Schiber.[24] The state's restructuring act provides for governmental aggregation of either the opt-in or opt-out variety. Of the approximately 600,000 retail customers who have chosen direct access in Ohio in the first year, the vast majority have entered buying pools organized by their municipalities or other government entities.

In other respects, the restructured retail and wholesale markets bear many similarities to the situation in Illinois, another state that is in the process of becoming part of the Midwest ISO system. As in Illinois, direct access has been chosen by a large number of customers in only one part of the stated -- the northern Ohio area served by FirstEnergy subsidiaries that have high electric utility prices -- and there are few competitive providers in most other parts of the state, where electric utility prices are low. There are mixed views about the adequacy of the transmission grid, and much will depend on the early successes (or failures) of the Midwest ISO.

What is curious to an outside observer is that in Ohio there is a greater sense of achievement and optimism about restructuring than there is in Illinois, despite the highly uneven record of direct access so far, and the uncertainties surrounding the adequacy and management of the transmission system. Perhaps the difference can be accounted for, at least in part, by the success and pride of ownership of the aggregation feature. Furthermore, the legislation contains provisions that provide incentives for each utility to reach a target of 20% of customers choosing direct access, and the sense seems to be that it is only a matter of time before the market opens up more evenly.

The Ohio Consumers' Counsel's assessment is: "While electric choice is off to a reasonably good start in Ohio, the results are far from conclusive. At the current time, most residential customers in Ohio are better off than they were before electric choice...But it will take time and effort for Ohio's competitive electric market to develop and mature. In the meantime...Ohio awaits the arrival of additional new electric suppliers for residential customers..."[25]

Legislation and Regulations

[24] Alan R. Schriber, Ohio Electric Choice: One Year and Counting, Public Utilities Commission of Ohio news release dated December 27, 2001.
[25] Ohio Consumers' Counsel, End-of Year Report: A Review of Ohio's Electric Market in 2001, January 9, 2002

On July 6, 1999, SB 3 was signed into law. Under the Act, the commission is to supervise a transition to retail electric competition during a “market development period” that will end by no later than December 31, 2005 (earlier in the case of one utility).

Generation and   services were opened to competition on January 1, 2001, and the commission is required to initiate a proceeding by 2003 to determine whether customer services such as metering, billing and collection should also be made competitive.

Rates were reduced in 2001 and are frozen for a period of at least five years. The utility is required to continue to provide standard offer service at these rates. Shopping credits for customers who switch to competitive providers are to be set at levels that induce a target of at least 20% of customers to switch by December 21, 2003. Customers who switch may get one bill -- from the distribution utility -- or two, one from the utility and one from the competitive provider.

Stranded cost recovery is provided for. Utilities may offer both non-competitive and competitive services, provided there is structural separation. Functional separation is permitted only on an interim basis.

At the end of the market development period, utilities are required to engage in open, competitive bidding procedures to supply standard offer services.

Wholesale Market Profile

There are several major electric utilities in Ohio (although two holding companies -- FirstEnergy and American Electric Power -- dominate electricity supply in the state), and the electricity grid connects the state to neighboring states. Ohio’s utilities are joining the Midwest ISO, which has a green light from FERC to create a regional RTO. There is a certain amount of generation construction underway or planned, but there are still concerns over the adequacy of the generation supply situation, and the effectiveness of control and planning of the transmission grid.

FirstEnergy, the parent company of Cleveland Electric Illuminating Company, Toledo Edison in northern Ohio, and Ohio Edison, has made a portion of its generation capacity available to competitive marketers. No other Ohio utility has taken a similar step. This may be part of the reason why retail competition has been successful only in northern Ohio, and to a lesser extent the Ohio Edison area, so far.

Interestingly, the wholesale power market in Ohio was subject to scrutiny by the PUCO after a period of disruption in June 1998. The commission found that an extremely constrained supply situation had developed. The regional reliability council had predicted that supplies would be tight, but a combination of factors coincided to create a worse situation than was expected. It was rather like the California experience in 2000, except that it was far from being as bad as California's "perfect storm." The factors included scheduled and unscheduled plant outages, hot weather, transmission system constraints, and non-performance by certain power marketers.

Although FERC staff studied the matter and concluded that a recurrence was unlikely, the Ohio commission was "somewhat less optimistic," in view of traditional problems like extreme weather and new problems like the reduced predictability of transmission system performance "in view of burgeoning wholesale power transactions and the prospect of retail wheeling."[26] The commission added that environmental restrictions on power plant operations could make the situation more precarious.

The commission also stated that, "The manner in which retail wheeling is implemented will also affect the extent to which the supply and demand of electricity is balanced. Without the implementation of public policy that encourages effective competitive entry in the generation market, assures coordinated operation of the transmission system, facilitates access to price information, and encourages utilization of financial hedging instruments, events may conspire again to disrupt electricity supplies and drive prices up. If competitively induced downward pressures on prices are not present, Ohio's major electric utilities will be in a position to exercise market power. (Report, pages ii-iii)

To ensure that "there is effective competition at the outset of any retail wheeling environment," the commission listed some public policy implications of the June 1998 events. These included actions to place regional transmission under the control of an RTO, to facilitate the development of power exchanges and risk management tools like forward markets, and to retain explicit Ohio jurisdiction to prevent abuse of market power. (Report, p. iii)

There will presumably be considerable attention directed at the issue of wholesale market adequacy to support direct access, and the potential for exercises of market power, during the remainder of the market development period which ends in 2005. PUCO chairman Schriber has noted that "federal issues regarding the interstate transmission of electricity have hindered the development of electric competition in Ohio. Working with the Federal Energy Regulatory Commission and other states to improve our regional transmission system is one of the PUCO's biggest priorities for next year...Competition and choice will continue to

[26] Public Utilities Commission of Ohio, Ohio's Electric Market June 22-26, 1998: What Happened and Why, a report to the General Assembly (web version undated), p. ii.

develop as a more efficient interstate transmission system falls into place and the wholesale electric market improves."[27]

Retail Market Situation

The development of direct access in the period of a little more than a year since it was initiated on January 1, 2001 has been highly uneven. In the northern Ohio service territories of FirstEnergy's subsidiaries, which have high utility rates, many customers have switched to competitive providers. This includes 54% of Cleveland Electric Illuminating Company's residential customers and 35% of Toledo Edison's residential customers. In the area of Ohio Edison, the third subsidiary of FirstEnergy, 17% of residential customers have switched. In the service areas of the other five major electric utilities, fewer than 1% of residential customers have switched, and there are few competitive providers.

What lies behind these figures? A major factor is, of course, the variation in utility rates across the state. Also, FirstEnergy's decision to make a portion of its generation capacity available to competitive marketers fuels the competitive market in northern Ohio. The other major factor is governmental aggregation. If high rates provide the motive for switching, aggregation -- as well as competitive supplies -- provides the means. The legislation provides for the formation of buying groups by municipalities and other governmental groups. Of the more than 600,000 residential electric customers who switched to new providers during 2001, the vast majority did so as members of buying groups. Mostly in northern Ohio, 158 communities have decided to aggregate so far.

The legislation allows municipalities and others to adopt either in an opt-in or an opt-out model. In the opt-in case, customers must request membership. (This is the only model allowed in some states, such as New Jersey, that are concerned about "slamming." It can have the effect of being a barrier to aggregation.) In the opt-out case, a municipality signs up its residents as participants automatically, but it must allow them to opt-out (choose not to participate) if they wish.

It is an over-simplification to describe customer inclusion in Ohio's opt-out model as "automatic." The rules require municipalities to get public approval before they can bind their residents. First, a majority of voters in the municipal area have to vote for it, which means it has to be put on the ballot. Second, the municipality has to form a plan of operation and management, and must hold at least two public hearings where residents can air their concerns. And third, customers must be notified of the planned switch. Even if initially included, customers have the opportunity to opt-out every two years.[28]

[27] Alan R. Schriber, Ohio Electric Choice: One Year and Counting, Public Utilities Commission of Ohio news release dated December 27, 2001.
[28] PUCO, Energy Governmental Aggregation: The PUCO's Guide to Community Buying Groups.

Much of Ohio's switching has, in fact, resulted from one deal, described as the country's largest-ever aggregation contract. Northeast Ohio Public Energy Council, representing 100 Cleveland-area communities with 400,000 customers, selected Green Mountain Energy Company in as its supplier for a period of six years starting in September 2001. The contract contains provisions for clean and renewable energy resources.[29]

The importance of aggregation in easing market entry is evidenced by the fact that Green Mountain had earlier decided *not* to enter the Ohio retail market, on the grounds that shopping incentives "make it difficult for Green Mountain to offer renewable energy to customers there at an attractive price, at least when we're competing for those customers one-by-one."[30]

In a "First-Year Report Card on Electric Choice," the Ohio Consumers' Counsel, Rob Tongren, concluded that customers were better off after the first year of direct access than they had been a year earlier -- customers had switched, rates were down -- but he also said that there was much room for improvement.

Among the issues that the Consumers' Counsel believes need to be addressed are the following. A state plan is needed to spur competition in areas of the state where there are currently no alternative suppliers. Rules need to be developed for the competitive bidding process that utilities are required to offer at the end of the market development period, including guidelines about participation by utility affiliates. Metering and billing services need to be reviewed; advanced metering needs to be developed. The Midwest RTO needs to be fully implemented. Market power needs to be monitored by the federal authorities. And a federal mechanism is needed to ensure the adequacy of power reserves in the wholesale market.[31]

[29] Akron Beacon Journal, February 16, 2001, reported in Restructuring Weekly.
[30] Green Mountain vice president Karen O'Neill, reported in The Electricity Daily, January 5, 2001.
[31] Ohio Consumers' Counsel, End-of Year Report: A Review of Ohio's Electric Market in 2001, January 9, 2002.

Oregon

Oregon is an example of a state that has delayed introduction of direct retail access in light of the instability of the Western wholesale electric power market caused by the California electricity crisis, and the failure of competitive providers to enter the retail market in Oregon.

Oregon's Electric Industry Restructuring Law, SB 1149, which was passed in 1999, provided for direct retail access commencing on October 1, 2001. In the summer of 2001, HB 3633 delayed customer choice until March 1, 2002. After that date, business customers may choose to switch to competitive providers, but they will also have the choice of staying with regulated utility service at cost-based rates if they wish to do so. The Oregon PUC may waive this requirement for large business customers after July 1, 2003, if it makes certain findings about market development. These include findings that supplies are adequate and reliable, customers can obtain multiple offers from alternative providers, and prices are not unduly volatile.

HB 3633 does not include direct access for residential customers, although small business customers may, if they wish, switch to competitive providers. Residential customers will now be offered a choice between several regulated options by their utilities. These options include a traditional basic rate, a time-of-day supply service, and certain green power alternatives.

The commission must report to the legislature by January 1, 2003 "on whether residential electricity consumers would benefit from direct access to electricity services. The report shall address, at a minimum, issues of market development for residential and small-farm consumers..."

The commission is directed to develop policies to eliminate barriers to the development of a competitive retail market. Three competitive providers have been certified by the commission, but they are complaining that they are being squeezed out of the market by the incumbent utilities. Among the barriers that they face is an exit fee attached to sales to direct access customers to recover the stranded costs of the incumbents.[32]

[32] The Oregonian, February 3, 2002, reprinted in Restructuring Weekly.

Pennsylvania

Summary

Pennsylvania is often regarded as the poster child of electric restructuring. The principal reason is that a number of customers have switched to competitive providers. The factors that account for switching include high utility rates and, more significantly, higher shopping credits than in most other states. The result has been that some customers have found it worthwhile to shop, and it has been profitable for some marketers to target small customers as well as large ones.

Closer scrutiny shows, however, that Pennsylvania's experience, like that of other states like Ohio and Illinois, has been highly uneven and has been influenced by utility-specific circumstances. Of the retail customers served by alternative suppliers as of January 1, 2002, 98% are in the Duquesne Light (Pittsburgh) and PECO Energy (Philadelphia) service territories, while in all other service territories less than one percent of customers have switched.[33] And Pennsylvania has not been immune to the "prodigal customer" problem that other states have experienced. Of the Pennsylvania customers who had migrated to the competitive market by April 2001, 30% have switched back to utility providers as of January 2002.

The other significant feature of the Pennsylvania experience is that the electric system had already for many years before restructuring been operated and planned as part of a tight pool by Pennsylvania-New Jersey-Maryland Interconnection (PJM). Under the aegis of FERC, PJM has now been transformed into an ISO. While PJM has its problems, it has clearly provided a stable wholesale market structure without which Pennsylvania's retail restructuring effort would have been much more problematic.

The Pennsylvania PUC chairman Glen R. Thomas believes that the example of Pennsylvania is a good one and that states should continue in the direction of restructuring. He argues that "the perception that competition is dead after California and Enron is wrong...Don't look at California or at Enron for the lessons of competition. Look at Pennsylvania. Following a year of bad news, Pennsylvania remains the national model for competition done right."[34]

Pennsylvania's Consumer Advocate sees the glass as half full rather than half empty. "I think our policy goal should be to stay the course and continue to provide protections for consumers while we see how competitive markets

[33] Pennsylvania Office of Consumer Advocate, Pennsylvania Electric Shopping Statistics, January 2002.
[34] Address to National Association of Regulatory Commissioners' Winter Meeting, reported in Pennsylvania Public Utility Commission press release dated February 12, 2002.

develop."[35] He recognizes that "it is impossible for a successful retail market to develop unless the wholesale bulk power markets are workably competitive," but he believes that the market failures of California will not occur in Pennsylvania. "The PJM markets are far from perfect but they are, in my opinion, far superior to virtually every other wholesale market region in America."[36]

In the retail markets, the Consumer Advocate notes that competitive suppliers are still supplying about 10% of customers. He acknowledges that many customers have returned to utility service, but he believes that "the way to increase retail competition in Pennsylvania is by fixing the remaining flaws in the wholesale market, not by increasing retail rates and violating the price caps that were supposed to protect consumers during this transition period."

Legislation and Regulations

The Electricity Generation Customer Choice and Competition Act of 1996 initiated retail competition with a pilot program in 1998. Two thirds of Pennsylvania's retail customers became eligible to choose alternative electricity suppliers by January 1999, and all the remaining retail customers became eligible by January 2000.

Competitive providers have to be licensed by the Pennsylvania Public Utility Commission and have to provide a performance bond or other surety. Generation services have been opened to competition, and in some service territories competitive providers may also offer customer services such as metering and billing.

Utilities must provide standard offer service to customers who do not choose competitive providers. Utilities are also required to be providers of last resort for those customers who choose to return to the utility or whose suppliers fail. The terms and conditions of provider of last resort service need not be the same as those for standard offer service -- e.g., a minimum period can be required.

There has, of course, been a loss of state jurisdiction to federal authorities and regional entities. This affects the roles of state regulators and consumer advocates. As the Pennsylvania Office of Consumer Advocate reports, "Since much of the decision-making that affects Pennsylvania electric consumers now occurs at the federal and regional level, the OCA has greatly expanded its participation in key

[35] The quotes in this paragraph and the next are from, House Judiciary Committee Testimony of Sonny Popowsky, Consumer Advocate of Pennsylvania, November 27, 2001.
[36] In other testimony, before the Pennsylvania House Consumer Affairs Committee Regarding Electric Reliability, on March 7, 2001, the Consumer Advocated emphasized that it was essential to ensure that planned construction, and construction that was actually proceeding, would be enough to match demands, and would not be overly dependent on natural gas.

electric proceedings before (FERC) and in the committees of the PJM Interconnection."[37]

Restructuring Activities to Date

Functional separation of generation is required of utilities, rather than structural separation or divestiture. However, several of the state's utilities have voluntarily transferred generation assets to separate subsidiaries of their holding companies, and in some cases have divested generation assets. For example, Duquesne and the GPU subsidiaries Metropolitan Edison and Pennsylvania Electric Company have completed their divestiture of generation assets.

Wholesale Market Profile

Pennsylvania utilities are members of the PJM Interconnection that is now operating as an ISO and has responsibility for ensuring system reliability in the region, which in addition to Pennsylvania includes New Jersey, Maryland, Delaware, the District of Columbia and part of Virginia.

PJM rules include a mandatory generation reserve requirement for all companies who serve customers in the area. It also administers an installed capability (ICAP) market.

FERC is encouraging PJM to combine with other ISOs in the Mid-Atlantic and Northeast to create a large regional RTO. It is not certain that this combination will take place.[38] PJM has announced its intention to explore merging with the Midwest ISO.

PJM functions as an independent system operator and also runs the wholesale power markets in its area. As the Office of Consumer Advocate has noted, "PJM's rules for and operation of those markets is critical to ensuring that retail competition in Pennsylvania will work...(FERC) required that RTO and ISO filings reflect certain basic governance and pricing characteristics, including requirements for independent governance and elimination of rate pancaking...The OCA's main challenge in the federal electric arena is to ensure that the proper RTO structures and rules are in place to protect consumers from the potential for

[37] Annual Report of the Pennsylvania Office of Consumer Advocate, Fiscal Year 2000-2001, November 2001.

[38] A recent report titled Economic Assessment of RTO Policy prepared for FERC (ICF Consulting, February 26, 2002) concluded that properly functioning RTOs, with consistent and effective market design throughout the country, would bring substantial economic benefits. However, the report found that the creation of larger as opposed to smaller RTOs would bring only minor additional benefits, unless larger RTOs resulted in more effective market design than smaller ones. This report may dampen FERC's enthusiasm for larger RTOs, unless of course FERC believes that larger RTOs would have better governance and market design.

market power abuses and to support competition in both the wholesale and retail markets so that even small consumers can benefit from retail choice."[39]

In November 2001, the Pennsylvania Public Utility Commission opened an investigation into the operation of wholesale electricity markets. This followed on the publication of a PJM report that found that during the period January through March 2001 market power had been exercised to raise prices on the installed capability (ICAP) market. The PUC chairman has called for steps to "hasten the maturing of the wholesale power markets."

Retail Market Development

Closer scrutiny shows, however, that Pennsylvania's experience, like that of other states like Ohio and Illinois, has been highly uneven and has been influenced by utility-specific circumstances. Of the 551,106 retail customers served by alternative suppliers as of January 1, 2002, 98% are in the Duquesne Light (Pittsburgh) and PECO Energy (Philadelphia) service territories. In all other service territories apart from Duquesne's and PECO's, less than one percent of customers have switched.[40]

Aggregation of a kind is responsible for about 41% of the customers who have switched. PECO agreed in its restructuring plan to assign 20% of its residential customers, for whom it was provider of last resort, to a special Competitive Discount Service. A competitive supplier would be selected for these customers as a block. Three bids were obtained, and New Power Company was selected as supplier. Later, Green Mountain Power was selected to provide power to an additional group of PECO customers.

In addition to the uneven development of the direct access market, Pennsylvania has not been immune to the "prodigal customer" problem that other states have experienced. Between April 2001 and January 2002, 30% of the Pennsylvania customers who had migrated to the competitive market switched back to utility providers when wholesale market prices rose relative to standard offer rates.

A new kind of problem faced the Pennsylvania authorities when Utility.com, a competitive provider, went out of business in 2001. A number of retail customers were left without a provider, and since the Utility.com website went down, customers didn't know the status of their consumption or bills. As the OCA said in a December 13, 2001 bulletin, "The company has no employees, no address and no website. CM Business Credit Services, Inc., a California firm that helps insolvent businesses to close, is handling any remaining claims against the company." The OCA tried to provide customers with the information they would need to submit claims and switch back to utility provider of last resort service.

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[39] Annual Report of the Pennsylvania Office of Consumer Advocate, Fiscal Year 2000-2001, November 2001, p. 17.
[40] Pennsylvania Office of Consumer Advocate, Pennsylvania Electric Shopping Statistics, January 2002.

Texas

Summary

Texas had been intensively investigating and negotiating electric restructuring for some time before the California electric crisis occurred. There was considerable political commitment to restructuring, which was supported by then-governor George W. Bush and then-Public Utility Commission of Texas chairman Pat Wood III.

Factors that favored restructuring in Texas included the state's control through the Electric Reliability Council of Texas (ERCOT, now the ERCOT-ISO) of its own intra-state electricity grid, and compromise features of the legislation that gave it continued support. These features included limits on the sizes of incumbent utilities in the restructured wholesale market.

Convinced that its market design would not be vulnerable to a California-type failure, Texas decided to proceed with direct access for all customers on January 1, 2002, as scheduled, after a five-month period during which a pilot program was in place, designed to identify technical problems and give participants a chance to iron them out.[41]

As far as the Texas authorities are concerned, the market's first responses have been promising, despite some initial technical glitches, with competitive suppliers functioning in the market and a number of customers switching away from their incumbent utilities. The independent power industry already has a foothold in the generation business in Texas, and, as required under the restructuring law, utilities are reducing their control of generation. The law also allows for retail customer aggregation.

At this point, the Texas authorities are optimistic. There are some skeptical observers, such as the editor of Public Utilities Fortnightly, who sees in Texas one of the problems that bedeviled the California utilities -- vulnerability to high wholesale prices while their retail prices for standard offer service are frozen (after initial reductions) until 2007 -- although he also recognizes the Texas advantage of having "a state-regulated ISO, dedicated to state interests."[42] It is too soon to be able to dismiss this type of concern.

[41] Computer problems delayed the start of the pilot program by two months. Restructuring has been delayed in the non-ERCOT portion of southeast Texas served by Entergy, which is a member r of the Southeastern Reliability Council (SERC). For the SERC area, FERC has not approved an RTO, which is a prerequisite for direct retail access under the Texas legislation. Xcel Energy regulated service is being retained in The El Paso and Texas Panhandle areas, which are not being opened up for competition for the next three and five years respectively, and deregulation is being delayed indefinitely in the Southwestern Electric Power Company (SWEPCO) area of northeast Texas.
[42] Public Utilities Fortnightly, February 1, 2001, pages 4-6.

The continued success of Texas restructuring will depend, as it does in other states, on the twin pillars of a workably competitive wholesale market -- a regulatory and market framework within which independent power producers are encouraged to maintain adequate supplies of generation -- and an effective ISO or RTO that can monitor, identify, and correct market power and other market abuses. And in the retail market, the success of competition will depend, as it does in other states, on not only a competitive wholesale market, but also a level playing field that enables new entrants to acquire retail customers individually or through aggregation. As far as the Texas Public Utility Commission is concerned, these essential features are in place.

<u>Legislation and Regulations</u>

The Texas Electric Choice Act, SB 7, was signed on June 18, 1999. It provides for direct access for all retail customers beginning January 1, 2002, after a pilot program period, which was planned to start in June 2001 but was delayed for technical reasons to August 2001. Initially, generation and billing services are opened to competition, with metering to follow later. Standard offer service is available from the utility for residential and small commercial customers.

Structural (corporate) separation of generation by divestiture or transfer to an affiliate company is required. Utilities must also be separate from retail electricity companies (REPs), which are entities that may market electricity to customers. The distribution utility itself may not participate in the wholesale or retail market except to purchase electricity for its own requirements for standard offer service. An REP which is affiliated with a distribution utility cannot sell electricity in the utility's service territory, except as standard offer provider, for three years, or until at least 40% of residential and small commercial customers have switched to competitive providers, whichever comes first. This means that it cannot offer services at different prices until this 40% condition is met.

An REP serving an aggregate load of more than 300 MW must sell at least 5% of its energy for three years to residential customers. By this provision, and the restrictions on affiliated REPs, SB 7 is intended to pry open the small-customer market to competitive entry, notwithstanding the continued low-cost option of standard offer service.

Aggregation or pooling of customers is permitted, provided the aggregator registers with the Commission. Aggregators may include cities and towns, non-profit organizations, and businesses.

An important feature of the Act is its provisions intended to break up the potential market power of incumbent utilities and prevent new entities from establishing and exercising market power. Utilities and their affiliates must auction off 15% of their generation assets. This provision -- which may be achieved by leasing or some similar method, as opposed to outright sale -- is in place for five years, or until at least 40% of residential and small commercial customers in the area have switched to competitive providers, whichever comes first.

And, wholesale generators may not own more than 20% of the installed capacity located in, or capable of delivering power to, a power region. This requirement may be waived in the case of utilities in a power region that is not entirely within Texas. Generators who are found to violate this requirement must file a market power mitigation plan.

An ISO must be established in each area. ERCOT is under the primary jurisdiction of the state Commission, but FERC has jurisdiction over some areas of the state in which utilities are interconnected with neighboring states or have interstate holding companies.

The state Commission may delay competition -- as it has done in certain areas of the state -- if it determines that the power market in the area is not yet able to offer fair competition and reliable service to customers.

Wholesale Market Profile

Most parts of Texas are in the area covered by the Electric Reliability Council of Texas (ERCOT). Texas is in a unique situation in having its own state-regulated reliability council. Listing its reasons for optimism about the prospects for success of retail competition in Texas, the state Commission has said that: "Unlike other areas of the United States, where Federal and state policies relating to the electric industry are sometimes inconsistent, regulatory authority with respect to ERCOT rests exclusively with the Texas PUC."[43] For other states, restructuring involves allowing utilities to shift their generation out from under state regulation, while in Texas there does not have to be any such release of assets from state jurisdiction (at least, not in the ERCOT area). ERCOT has now evolved into the ERCOT-ISO. It controls the transmission system and is responsible for system reliability.

ERCOT does not operate a centralized wholesale power market. The intention is to allow market participants to develop markets, rather than preempt or channel their efforts as other states have tended to do.

The auctioning off of 15% of utility generation assets, and the cap of 20% on the market share of a single generator are aimed not only at opening up the market to competitive entry, but also to avoid a situation in which large generators are in a position to exercise market power. These provisions respond to market power concerns expressed by the Texas Office of Public Utility Counsel (OPUC) and others.

[43] Public Utility Commission of Texas, Scope of Competition in Electric Markets in Texas, Report to the 77th Texas Legislature, January 2001, p. 3.

Dallas-based Texas Utilities (TU) and Houston Lighting and Power (HL&P), which had 40% and 28% respectively of the generation capacity in ERCOT, and between them more than 80% of the peaking capacity, were the main cause of concern. A consultant's study Commissioned by OPUC had reached the following conclusions.

> (M)arket power will exist in ERCOT. Both TU and HL&P would have the ability to exert control over prices and increase profits by noncompetitive pricing or restricting supply. Further, the ability to control prices will exist in both the summer peak season as well as the off-peak months when plant maintenance occurs. One of the factors that compound the market power of TU and HL&P is the ability to 'leverage' the diversity of their supply mix. These large suppliers can increase profits on lower cost coal and nuclear baseload plants by restricting the supply (or increasing prices) of higher cost (gas fired) intermediate and peaking plants. Even though such strategies may reduce market share or even profits for gas fired generators, the increase in profits on baseload plants more than offsets possible decreases in profits on gas plants."[44]

The study recommended that, "Divestiture is the most effective means of dealing with market power." It noted that utilities in many other states had divested generation assets to reduce market power and quantify, and possibly mitigate, stranded costs. Divestiture of peaking capacity was the best course. No one generator in Texas should own more than 10,000 MW of gas-fired capacity.

Another study done for OPUC by a different consultant reached somewhat similar conclusions regarding the problem of horizontal market power, and recommended that "the best competitive policy would be to reduce the size of the largest ERCOT suppliers..."[45] This report also addressed vertical market power, and concluded: "The only way to completely address vertical market power problems is through the complete divestiture of all generating assets by integrated utilities."

The Commission is aware of the importance of these issues. "A vibrant wholesale market is important for a retail market to work," it said during 2001, but it believes that the favorable environment for merchant power plants in Texas, including standardized procedures for interconnection to the grid, will ensure that that the state does not run short of power the way California did.[46]

The Commission contrasts the power plant construction in Texas from that in California and some of the northeastern states.

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[44] Office of Public Utility Counsel of Texas, Electric Power Restructuring Issues for ERCOT: Market Power and Divestiture, October 1998.
[45] Report to the Office of Public Utility Counsel on the Criteria for the Sale of Generation Assets by ERCOT Generation-Owning Utilities, Criteria for Electric Generation Divestiture in ERCOT, October 1998.
[46] Public Utility Commission of Texas, Scope of Competition in Electric Markets in Texas, Report to the 77th Texas Legislature, January 2001, pages 3-6.

> In California and New York, it appears that the primary impediment is the state siting process. In New England and Pennsylvania, the construction of new generation appears to have been slowed by transmission interconnection rules that require the developers of new generation projects to pay for upgrading the transmission network so that the output from the generation plant can be moved to the market. In some of the Northeastern states, the natural gas pipeline infrastructure is not adequate to support significant levels of new gas-fired generation, which is the most economical technology in the market today...
>
> Texas has adopted a different approach on many of these issues. Non-utility generation does not require a state license, other than environmental permits, and new generation facilities are not required to pay for transmission facilities to deliver their power to market. Texas also has a strong gas-delivery infrastructure...A better supply-demand situation is already evident in Texas.[47]

Retail Market Developments

After initial rate reductions, there is a rate freeze for standard offer service for a five-year period, or until 40% of eligible customers have chosen competitive suppliers, whichever comes first. The supplier is the distribution utility's affiliated REP. The standard offer rate is termed "the price to beat" in the service territory.

The Texas Office of Public Utility Counsel has expressed concern over the utility practice of offering special discounted rates to large industrial customers. Traditionally, the concern was that special rates could result in cost-shifting to other customer classes. On the eve of direct access, the additional concerns are that special rates and contracts may tie up customers before they have an opportunity to shop around in the competitive market, and may undermine the equitable recovery of stranded costs. The Commission has taken steps to address these concerns.

It is too soon to know how many customers will switch to competitive providers in Texas. According to early reports, more than one half of the electricity purchased by large customers is now coming from competitive providers. The Houston Chronicle reported on February 14, 2002, that 3% of residential customers in the state had switched suppliers, which would be a significant achievement in a little over one month.

It is also too soon to know how quickly initial technical and other problems will be resolved. There have been some initial technical problems, and the rate of customer complaints is high. ERCOT is initially taking 30 days, or even 60 days,

[47] Public Utility Commission of Texas, ibid., p. 37.

to switch customers. And there are allegations of slamming and deceptive marketing practices.

Governmental aggregation appears to have taken hold quickly in Texas. A recent list of aggregation programs includes one for 142 school districts, one for 46 local governments, one for 180 school districts and 11 other public entities, one for 71 cities and one for 40 cities. The annual savings for these programs are estimated at about $150 million.[48]

Another early development is that non-utility providers of last resort have been selected for a number of utility service territories.

[48] Electric Utility Restructuring Legislative Oversight Committee, February 5, 2002. On PUC website.

Vermont

Summary

Although an early leader in New England and the nation in evaluating the benefits of retail choice and competition, Vermont was unable to agree on an implementation plan for restructuring its electric utility system. It came close in 1997 when the Vermont Senate passed a bill supported by the Governor, utility commission, many business groups, and the state's two large investor owned utilities. However, opposition by liberal Democrats in the Vermont House, as well as some consumer advocates and municipal utilities, was enough to prevent passage. Subsequent events in wholesale markets, including price increases and the California debacle, convinced most legislators and policy makers to adopt a "wait and see" approach.

Electric System

Two large investor owned utilities, Central Vermont Public Service and Green Mountain Power, serve approximately 70 percent of the state's 1100 MW peak load. One additional IOU, Citizens Utilities serves about 60 MW of load. The state's largest city is served by a municipal utility, Burlington Electric, with about a 70 MW peak load. Two cooperatives, twelve small municipals, and one small IOU serve the remaining 200 MW of peak load. The entire state is dispatched as a single entity by ISO New England, the regional administrator of the New England bulk power system, through a cooperative arrangement among Vermont's utilities embodied in an entity called the Vermont Electric Power Company (VELCO). VELCO was created in the1970s to allow for the more efficient dispatch of power; in essence, VELCO is an early for-profit Transco. Although dominated by the two large IOUs, CVPS and GMP, the voting and management structures are designed to accommodate minority views.

Restructuring history

In 1996, Vermont was in the vanguard of states seeking to restructure the states electric industry and provide retail choice to consumers. The VT Public Service Board, the state's utility commission, had conducted a series of workshops (The Vermont Roundtable on Restructuring) to establish basic principles and issued a report on the opportunities and necessary conditions for the provision of competitive electric services (Docket No. 5854, Order of 12/30/96).

A significant impetus for restructuring had to do with impending rate increases to cover the costs of expensive generation and purchased power contracts. Large customers were concerned that their competitive position within their industries would suffer if they were forced to absorb large rate increases over the coming years. Consequently, a great deal of the debate and tension over restructuring was directly related to the utilities insistence that they receive full recovery for their "stranded costs" and the reluctance of their customers to agree in advance to any such "guaranteed" recovery. Other stakeholders, including the Vermont Department of Public Service (the consumer advocate and state energy policy agency), had significant concerns about the "stranded benefits" that would occur as a result of restructuring.

In early 1997, Senate Bill 62 (S.62) was introduced as a comprehensive plan for restructuring Vermont's electric industry. After three months of debate in four Senate Committees, it was approved by the full Senate in early April and sent to the Vermont House for review. The House leadership focused almost solely on the stranded cost issue and took a very public stance that ratepayers should not pay anything for the utilities' expensive power contracts. S.62 proposed a fifty-fifty sharing between ratepayers and utility shareholders, after a Public Service Board proceeding to eliminate any imprudently incurred costs and mitigation of above-market prudently incurred costs. CVPS and GMP had already stated that S.62 would likely cause bankruptcy due to the impact of absorbing even fifty percent of the above-market costs. With neither side able or willing to negotiate, S.62 wallowed in perfunctory committee hearings over the next two years. Alternative and modified House and Senate proposals were unable to garner any significant support

Meanwhile, CVPS and GMP both became entangled in rate case proceedings where the VT Department and other intervenors pressed their claims that significant portions of the utilities' above-market contracts were the result of imprudent utility actions and should be disallowed for rate recovery. The outcome of these cases would have a significant impact on any restructuring efforts in the state.

In July 1998, VT's Governor Dean issued an executive order establishing a Workgroup to evaluate the best course for Vermont to take in regard to electric restructuring. In a report issued in December 1998, the Workgroup concluded that with appropriate protections and safeguards for consumers and utilities, retail choice could be beneficial to Vermont's economy. No particular initiatives followed.

In late 1999, the VT Board opened an investigation, in response to petitions from CVPS and GMP, to determine if retail competition could be implemented without specific legislative authorization. That investigation, although still technically open, has been inactive for the last three years.

More recently, the escalating costs of wholesale power that began in the fall of 1999 and continued through the winter of 2000-2001 have made many of the Vermont utilities' purchased power contracts more attractive. Combined with the well-publicized problems in California's wholesale power markets and smaller, yet significant, problems in the Northeast ISO-administered wholesale markets, many of the large customers of Vermont's utilities are less enthusiastic above a rapid move to retail choice. With the benefit of hindsight, some of the more vocal proponents of retail choice, including Vermont's five-term Governor, are endorsing a thoughtful re-evaluation. Many of the vocal critics of restructuring are proclaiming the wisdom of their early opposition.

Special features of S.62

Consistent with the VT Board's Order in Docket 5854, Senate Bill 62 proposed a comprehensive approach to retail competition. Some of the key features included:

- Stranded costs: a fifty-fifty cost sharing between ratepayers and shareholders after Board proceedings to eliminate any imprudent costs and to determine mitigation strategies (including securitization) of prudently incurred above-market costs.
- A functional separation of utility generation resources with strict codes of conduct to ensure arms-length relationships. Although divestiture was mentioned as an option, it was not required.
- A comprehensive education program for consumers about retail choice options
- An auction for retail providers of "basic service" (standard offer service) subject to terms and conditions set by the VT Board. Incumbent utilities may be awarded basic service contracts only if no other acceptable bids are provided.
- A competitive transition charge established by the VT Board to provide recovery of adjudicated stranded costs
- A system benefits administrator who would collect and distribute wires charges for the following programs:
  - A low income affordability program
  - An information disclosure program for consumers
  - An energy efficiency utility to provide statewide programs
  - A renewable portfolio standard for all retail providers (approximately 15% existing renewables; and 1-4% new renewables over ten years)
  - An emissions portfolio standard for all retail providers
- A net-metering provision for residential and commercial customers who install small renewable generation less than 50 kV.

Current status

Despite the inability of the legislature to enact a comprehensive bill such as S.62. Certain elements have been enacted through separate legislation and Board proceedings. In 1998, a net-metering provision similar to the one in S.62 was signed into law. In 1999, Vermont created the first statewide energy efficiency utility to oversee the implementation of comprehensive energy efficiency programs through a consortium of utility support.

As mentioned above, although there is technically an open proceeding before the VT Board on a utility request to allow retail choice, the docket has been inactive for the last three years. Based on discussions with VT Board staff, it is unlikely that any new restructuring proposals are imminent.

Virginia

We will address only one feature of the Virginia electric restructuring situation. The Virginia Electric Utility Restructuring Act requires each incumbent electric utility to submit a plan for the functional separation of the utility's generation, transmission and distribution assets and operations. The plan has to be filed with the State Corporation Commission for approval.

On January 3, 2001, American Electric Power Company-Virginia filed it proposed separation plan, which was not only a functional separation, but would transfer its generation assets and operations into a separate *corporation*, Genco. This new entity, which would be an affiliate of AEP-Virginia and a subsidiary of the AEP holding company, would be an Exempt Wholesale Generator and would no longer be under the jurisdiction of the Virginia commission.

During 2001, there were initiatives before the legislature that affected the AEP filing, and when these were resolved, the commission proceeded with the matter, requesting parties to attempt to enter into a stipulation on the issue.

In the resulting stipulation, the company agreed to continue with its current functional separation of its distribution, transmission and generation functions *by division*. During 2002, there will be a further enquiry into the terms and conditions for the proposed transfer of generation assets to an affiliate. "This inquiry will examine, among other things, conditions necessary for the maintenance of reliable electric service and the development of an effectively competitive market for generation services; and...AEP-VA will continue to use its best efforts to provide reliable service and to minimize generation costs to its retail customers."[49]

This matter, which is clearly not yet resolved in Virginia, underscores the concern of state commissions about loss of jurisdiction over generation assets, particularly when it is not clear that the FERC-regulated wholesale market is workably competitive. In the Virginia case, furthermore, there is concern that even if the wholesale market is highly competitive, prices may be higher than regulated rates, which are based on the relatively low embedded costs of service of the state's utilities.

[49] Virginia State Corporation Commission, Application of Appalachian Power Company D/B/A American Electric Power-Virginia for approval of functional separation plan, Case No. PUE010011, Order on Functional Separation, December 18, 2001.