Electric Industry Deregulation:

A Look at the Experiences of Three States

Executive Summary

In the late 1990s, several states, including Michigan, began deregulating their electric utility industry in the hopes that competition in the generation and sale of electricity would drive down prices to consumers. The enthusiasm for deregulation had waned in Michigan in recent years, but interest in electric market choice is now rising again.

Public Sector Consultants Inc. (PSC) was hired to review the experiences of other states that deregulated their markets and identify trends or issues that might be relevant to the current discussion of Michigan's energy policy. PSC conducted case studies of Texas, Illinois, and New Jersey—three states that represent a range of geographies, political leadership, and deregulatory approaches and policy frameworks. The case studies looked at the success of these states' deregulatory efforts through the lens of:

- How reliability and affordability changed
- Whether deregulation provided for adaptable energy policy

In our analysis, PSC found that while there were some benefits of electric market competition, particularly for larger industrial customers, broad success for deregulation has either not materialized or has come with other regulatory and financial costs. Specifically, the case studies found that:

- Deregulation does not necessarily lower electricity rates
- Rates are often more volatile under deregulation
- There are significant challenges with pricing default electric service—the service provided to residential customers who do not opt for, or cannot obtain, competitive electric service
- Electric capacity and reliability can be a substantial challenge
- Deregulation can reduce a state's control of its energy policy because of the stronger role regional transmission organizations and the federal government play in where electricity is generated
- New forms of market/government intervention to address market failures often have been necessary

Introduction

Impetus and Purpose of the Research

The focus on electricity deregulation waned considerably after the price spikes, rolling blackouts, and utility bankruptcies that accompanied California's energy crisis in 2000–2001,[1] and as other states experienced similar challenges. By the early to mid-2000s, some states had repealed electric choice laws or otherwise pulled back such efforts, while others stayed the course, hoping to capture the potential benefits of deregulation. A third group of states had little choice on changing direction, since power plants had been spun off from utilities to other companies, as required under the deregulation legislation.

While there was considerable media coverage of state deregulation activity up through the mid-2000s, there has been little research on recent experiences. Since the U.S. has been experiencing a cycle of low prices for natural gas (which is a major fuel source for electricity generation) and wholesale power, there has been renewed interest in some states, including Michigan, to look at deregulation again in an effort to increase competition and reduce prices for more customers. Michigan's administration and legislature have sought input on whether Michigan should revisit its market structure, including the 10 percent cap on electric customer choice instituted in 2008. As a backdrop, Gov. Rick Snyder has called for energy decisions that provide for reliability, affordability, and environmental protection. He wants the state's energy policies to be adaptable—a "no regrets" approach.

Many of the deregulated states now have at least a decade of experience, which can help to inform the policy debate in Michigan. Accordingly, PSC was asked by Consumers Energy and DTE Energy to review key deregulated states through the lens of:

- How reliability and affordability changed
- Whether deregulation provided for adaptable energy policy

Using these as a guide for our research, we reviewed the experiences and impacts in three key deregulated states: Texas, Illinois, and New Jersey.

1 California partially deregulated its electricity industry in 1996, and subsequent market manipulations by energy companies such as Enron created artificial shortages that caused substantial wholesale electricity price increases. The high wholesale prices squeezed the revenue margins for utilities because of the deregulation-required customer price caps, bankrupting or nearly bankrupting the state's two largest utilities.

Study Approach

In choosing states to evaluate, PSC picked three that represented different regions (South, Midwest, and East Coast), included a range of deregulation systems and policy frameworks, and reflected different political leaderships (Democratic and Republican).

PSC conducted literature reviews of deregulation generally in the United States for comparison of approaches and implementation issues; reviewed and analyzed primary and secondary documents on the implementation approach, prices, competition, reliability, and regulatory changes in each of the three states; and conducted interviews with state energy regulatory staff in Texas and Illinois. The information was compared to national trends on prices, generation capacity, reliability, and rates of residential and commercial switching. PSC also reviewed any energy policy or regulatory changes that were made subsequent to deregulation in order to fine-tune or correct deficiencies in deregulation policies.

Although environmental protection is part of the governor's energy policy platform, PSC did not include it within the scope of this analysis because it would have required significant additional analysis to isolate the effects of deregulation on the environment from the effects of other state and federal policies.

It is difficult, if not impossible, to document what would have happened in states that implemented electric choice had they maintained their regulated utility system (and vice versa). But looking at trends and patterns among states over time can help policymakers identify factors that affect the success, or lack of success, of electric choice programs and shape future energy policy decisions in Michigan and elsewhere. These cases studies attempt to highlight some of these issues and contribute to the ongoing dialogue about the merits of electric industry deregulation.

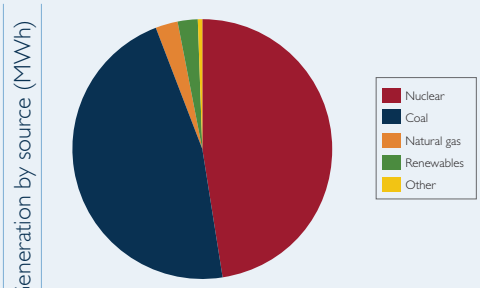
Deregulation in Illinois has—ironically—relied heavily on significant government intervention to control costs and encourage customer switching.

Summary

Illinois is an important state to review in the context of state experiments with electricity deregulation for two reasons. First, the deregulation process was protracted and highly controversial, and included years of legislative debate as well as a high-profile complaint and intervention by the state attorney general. Second, the turmoil associated with deregulation in Illinois—political, legislative, rate volatility, and other—reflected a lack of confidence in the ability of deregulation to ensure affordable, reliable power. This led Illinois policymakers to create new public entities and expanded roles for government in the purchase and sale of electricity in Illinois, essentially adding more regulation. Furthermore, it is not clear whether the recent price trends in Illinois are the result of deregulation, these new roles for government, or simply the result of current low natural gas and wholesale power prices.

History and Profile

- Deregulated in 1999 with commercial and industrial customers
- Regional transmission organization (RTO)/independent system operator (ISO): PJM and MISO
- Organized wholesale energy and capacity markets (PJM) and energy market (MISO), both under FERC jurisdiction
- Electricity sales (MWhs): 144,760,674 (#6 in nation)
- Average electricity price (cents/kWh in 2010): 9.13 (#24 in nation)



SOURCE: EIA, Illinois Electricity Profile, 2010.

Issues

Protracted Deregulation Process

Like many other states, Illinois went through a protracted process to deregulate its electric industry. It began in 1997 when the initial deregulation law was enacted and required the state's two investor-owned utilities, ComEd and Ameren, to spin off their generation to affiliated or unaffiliated companies. ComEd and Ameren continued to provide delivery of power and serve customers that did not select an alternative supplier. Retail access was initially limited to commercial and industrial customers in these service areas but expanded to residential customers.[1]

Deregulation did not take off as expected in terms of customer participation. The decade-long rate cap mandated in Illinois (which ended in January 2007) was one of the longest lasting rate caps in the nation, and it effectively discouraged alternative suppliers from entering the market. Through 2011, switching among residential customers was nearly non-existent. There was, however, a notable increase from 2011 to 2012—from 2% to about 22%, respectively—due in part to municipal aggregation efforts as discussed further below. Initial participation by small to medium-sized non-residential customers was also limited. In 2005, the state cautioned that the rate of switching among these customers was only around 5%. Participation among all types of customers has grown over time, however, particularly since 2011, and current levels are quite high in Illinois. According to the ABACCUS report for 2012, 22% of residential customers, 81% of medium-sized non-residential customers, and 93% of large customers had switched.[2]

TIMELINE

1997—Electric deregulation law passed

1999—Retail access available to some commercial and industrial (C&I) customers

2001—Retail access available to all C&I customers of investor-owned utilities

2002—Retail access available to residential customers

2007—Rate cap expires and prices surge; state attorney general files complaint against wholesale suppliers for market manipulation and excessive power prices; new legislation enacted that mandates $1B in rate relief for customers and creates Illinois Power Agency to procure power

2008—Residential customers first switch to alternative suppliers (participation low)

2010—Local governments authorized to aggregate load and solicit bids for sale and purchase of electricity

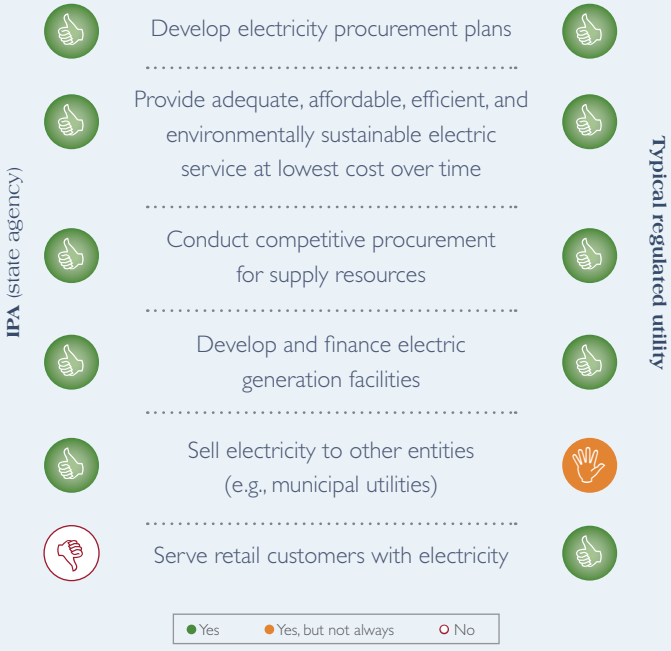
2012–13—500+ local governments pass referendums for municipal aggregation

Expanded Role for Government

In addition to mandating rate freezes, discounts, and customer refunds during the transition to deregulation, the Illinois legislature stepped in to create a new independent state agency, the Illinois Power Agency (IPA), to oversee the "electricity planning and procurement processes for residential and small commercial customers of Ameren and ComEd."[3] The IPA was created "in response to significant consumer electricity cost increases resulting from a utility-managed reverse auction process."[4] The utility auction process was eliminated as part of this reform and the new agency became responsible for procuring power; ensuring reliable, adequate service at the lowest total cost over time; and developing new resources, including coal, renewable energy, and others financed with state bonds. The legislative charge of the IPA is strikingly similar to the role of a regulated electric utility (see below), including the ability to develop generating facilities, except that the IPA is not permitted to sell directly to retail customers.

The IPA credits itself with lowering and stabilizing electricity prices in Illinois.[5] The agency reported in 2011 that its procurement activities have resulted in $1.64 billion in total savings for consumers since 2009.[6]

Role of IPA vs. Typical Regulated Utility



SOURCE: Public Sector Consultants using information on IPA's mission and objectives from the *Annual Report FY 2012* and Public Act 095-0481.

Although proponents of deregulation argue that one of the key benefits is providing customers the ability to choose their supplier, many deregulated states have seen limited participation by residential and small commercial customers.[7] In the first decade under deregulation in Illinois, participation by such customers was almost non-existent. In response to these trends and recognizing the need to make deregulation "work," Illinois enacted legislation to promote the ability of local governments to arrange for the sale and purchase of electricity. These municipal aggregation programs effectively allow the local government to make the "choice" on behalf of their residents (and sometimes small businesses). That is, local governments aggregate customers in their respective jurisdictions in order to supply power. Individuals must proactively "opt out" of the program in order to avoid switching their service. The IPA facilitates municipal aggregation by negotiating and supplying the power.

Municipal aggregation in Illinois has been widely adopted but is still new. As of May 2013, a total of 529 communities (including Chicago) passed referendums for municipal aggregation.[8] The 2012 ABACCUS report states that an estimated 60% of "switching" by residential customers in the state was due to municipal aggregation, according to the Illinois Commerce Commission. That percentage appears to have increased since 2012, given the number of local governments with active municipal aggregation programs initiated since 2012 and their associated populations. The state publishes the total number of customers that switch providers, but does not break down switching rates for customers under aggregation versus those that switch suppliers on their own. Nonetheless, there are more households in areas with municipal aggregation (with a supplier under contract) than the total number of residential customers that have switched as of the first quarter of 2013.[9] This suggests that municipal aggregation is driving a large portion of the current switching activity in Illinois.

Of those local governments that have selected suppliers, the rates appear attractive (averaging 4.55 cents/kWh),[10] but these rates were negotiated during a time of depressed wholesale prices and they have limited terms. While the experience with aggregation to date appears positive and has improved the customer "switching" statistics in Illinois, the track record is short. Moreover, aggregation raises important policy questions: Is this an appropriate role for local governments?[11] Will this approach stay in favor once market conditions fluctuate? And will these customers simply return to the incumbent utilities when that happens?

Affordability

Cuts in retail rates of up to 20% were mandated as part of the transition to deregulation in Illinois, and rates were frozen for a decade.[13] Prices surged when price caps expired in 2007, resulting in considerable political turmoil. Customers experienced double- and triple-digit increases in their electric bills in 2007, with allegations from the state attorney general that customers would be paying an extra $4.3 billion from 2007 to 2009 because of manipulation of prices by wholesale suppliers (including affiliates of ComEd and Ameren) in the electricity auction used to set the utility rates under deregulation. The state's complaint alleged that the deregulated generation affiliate of ComEd was charging the utility three times its actual cost to generate electricity to serve the utility's customers.[14]

After considerable squabbling in the state legislature over how to handle the rate increases, the state eventually brokered a deal in 2007 for major rate relief and other reforms with ComEd and Ameren to provide consumer refunds and credits totaling $1 billion. This was used to help offset some of the price increases.

Rate Shock in Illinois

Prices soar from 2006 to 2007 following expiration of rate cap.

ComEd

- 26–56% jump in residential prices from 2006 to 2007
- 60–70% increase for large commercial and industrial customers with some very large customers experiencing increases of over 100%

Ameren

- 49–125% jump in residential prices
- 80–130% increase for large commercial and industrial customers

Illinois has seen electricity prices come down, hovering around the national average—likely a function of the surplus capacity in wholesale markets and low commodity prices.[15] As seen elsewhere, including Michigan, the prices are largely a function of the initial rate freezes/caps and commodity prices, not the market structure (i.e., deregulation).[16] The Illinois Power Agency also purports to have played a key role in stabilizing prices.

> *"Five million Illinois residents are unnecessarily paying electricity prices that are double the actual cost of generating electricity…"*
>
> —Lisa Madigan, IL Attorney General, March 15, 2007[12]

As generation supplies tighten in the eastern United States with the retirement and retrofitting of older coal plants and if natural gas prices increase, regional wholesale prices could escalate and increase retail rates in Illinois.[17]

Conclusion

State and local governments have taken on expanded roles related to the purchase and sale of electricity in Illinois that suggest a fair amount of government intervention under deregulation. The government is essentially serving in critical roles traditionally provided by a regulated utility. This intervention is in response to what appears to be a perceived inability or lack of confidence in deregulation to ensure affordable, reliable service and bring about real competition. The initial trigger for state intervention in power procurement was the alleged market manipulation and excessive prices of wholesale suppliers in 2007. The state played a key role in investigating these issues and ultimately mandated refunds to customers in order to temper these rate increases. For local governments, the lack of customers electing to switch suppliers and the desire to stimulate competition has led to local governments effectively making this decision and negotiating prices for their residents. These state and local government roles bring into question whether this is a truly deregulated industry. Rather, it appears that the framework in Illinois has relied on new forms of market-based regulation, some of which have not been fully tested under alternative market conditions.

Endnotes

1. See Distributed Energy Financial Group, LLC, December 2012, *Annual Baseline Assessment of Choice in Canada and the United States* (2012 ABACCUS: An Assessment of Restructured Electricity Markets). Available: www.competecoalition.com/files/ABACCUS-2012.pdf (accessed 7-1-13). The ABACCUS report indicates that retail access was planned for 2002 for residential customers but moved up to late 1999/2000.

2. Distributed Energy Financial Group, LLC, *Annual Baseline Assessment of Choice*, p. 60.

3. Illinois Power Agency (IPA), *Fiscal Year 2012 Annual Report,* December 1, 2012. Available: www2.illinois.gov/ipa/Documents/Annual-Report-Illinois-Power-Agency-FY2012.pdf (accessed 6-5-13).

4. IPA, *Fiscal Year 2011 Annual Report.* Available: www2.illinois.gov/ipa/Documents/IPA_Annual_Report_2011_final.pdf (accessed 6-5-13).

5. IPA, *Fiscal Year 2011 Annual Report*, Executive Summary.

6. Ibid.

7. Surveys also suggest that, in general, many customers are not interested in selecting an alternative supplier.

8. A referendum is required to determine whether the aggregation shall be structured as an "opt out" program. For a list of communities, see Plug In Illinois, *List of Communities Pursuing an Opt-Out Municipal Aggregation Program* (updated June 28, 2013). Available: http://pluginillinois.org/MunicipalAggregationList.aspx?ob=1 (accessed 7-1-13).

9. Illinois Commerce Commission, April 29, 2013, Electric Switching Statistics as of March 2013. Available: www.icc.illinois.gov/electricity/switchingstatistics.aspx (accessed 6-24-2013). Over 2.8 million customers have switched providers as of March 2013 and the number of households within areas with municipal aggregation with suppliers selected exceeds 3 million based on the 2010 U.S. Census. See also Plug In Illinois, *List of Communities Pursuing an Opt-Out Municipal Aggregation Program*.

10. Average calculated by Public Sector Consultants.

11. The IPA cautions local governments that "This is a multi-million dollar contract on behalf of constituents: protections for you (the municipality) and residents beyond the minimum in the law are desirable—and potentially necessary." Illinois Power Agency, March 2012, *Illinois Municipal & County Electric Aggregation: What Do I Need to Know?* (Web conference presentation). Available: www2.illinois.gov/ipa/documents/MunicipalAggregationMarchWebinarIPAPresentation3-12-12.pdf (accessed 6-13-2013).

12. Press release, March 15, 2007, "Attorney General Madigan Alleges Price Manipulation in 2006 Electricity Auction: Complaint Seeks Reduction in the Price ComEd and Ameren Pay for Electricity." Available: www.illinoisattorneygeneral.gov/pressroom/2007_03/20070315.html (accessed 7-2-13).

13. Distributed Energy Financial Group, LLC, May 2006, Annual Baseline Assessment of Choice, p. 57; Illinois Commerce Commission, *Competition in Illinois Retail Electric Markets in 2005*. Available: http://ipu.msu.edu/resources/pdfs/Commission-Reports/IL-Competition%20in%20Illinois%20Retail%20Electric%20Markets%20in%202005.pdf (accessed 7-1-13).

14. Complaint by the People of the State of Illinois, Illinois Attorney General Lisa Madigan v. Exelon Generation Company, LLC, et al., March 15, 2007, p. 10. Available: www.illinoisattorneygeneral.gov/pressroom/2007_03/FERC_Complaint_public.pdf (accessed 7-15-13).

15. Potomac Economics (Independent Market Monitor for MISO), June 2012, *2011 State of the Market Report for MISO Electricity Markets*, pp. i-v. Available: https://www.midwestiso.org/Library/Repository/Report/IMM/2011%20State%20of%20the%20Market%20Report.pdf (accessed 6-6-13).

16. See Public Sector Consultants, November 30, 2006, *Electricity Restructuring in Michigan: The Effects to Date of Public Act 141 and Potential Future Challenges*. Available: www.pscinc.com/Publications/tabid/65/articleType/ArticleView/articleId/225/Electricity-Restructuring-in-Michigan-The-Effects-to-Date-of-Public-Act-141-and-Potential-Future-Challenges.aspx (accessed 7-1-13); see also Joint Response from DTE Energy, Consumers Energy, and MEGA, on Overall Question 1 (Structural Drivers of Electric Rates) and Electric Choice Questions 9 and 11, April 25, 2013. Available: www.michigan.gov/energy/0,4580,7-230--293322--,00.html (accessed 7-2-13).

17. Potomac Economics, p. v. See also, Monitoring Analytics, LLC (Independent Market Monitor for PJM), State of the Market Report for PJM, May 16, 2013. Available: www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013q1-som-pjm.pdf (accessed 6-6-13).

Deregulation in New Jersey has not resulted in electricity price decreases or desired in-state generation. This has led to tensions between state and federal authorities over control of the state's energy future.

Summary

New Jersey is an important state to review in the context of electricity deregulation for four reasons. First, the reason stated most often for the enactment of the legislation that deregulated New Jersey's electricity market was high electricity rates. After almost 14 years of deregulation, however, electricity rates continue to be high compared to those in other states, and New Jersey's relative position nationally hasn't changed. Second, New Jersey is an example of a state that has relied on a "capacity market" pricing system designed and operated by the federally regulated regional transmission organization (RTO) to induce needed new generation capacity. The ability of this pricing model to actually attract the investment necessary to build this new capacity has been questioned, as little new generation has been built to meet New Jersey's growing energy needs. Third, dissatisfied with the results of the RTO capacity market system in terms of both the price of power and its availability, New Jersey enacted new legislation in 2011 designed to create its own incentives for the construction of new generating capacity within the state—that is, a new form of state regulation and intervention. This attempt, however, has been contested by the RTO, the Federal Energy Regulatory Commission (FERC), and energy providers that want to import electricity into the state from outside New Jersey. This has led to the fourth key feature of the New Jersey deregulation experience: a dispute regarding who will control New Jersey's energy future—the state or the federal government via the RTO and FERC.

History and Profile

New Jersey passed its Electric Discount and Energy Competition Act (EDECA) in early 1999, one of a number of states to enact similar legislation in the late 1990s. As with many of these states, the legislation deregulated the energy generation sector but maintained a traditional cost-of-service regulation approach for the transmission and distribution segments of the industry.[1] Under this deregulated system, the state's four main utilities continued to own distribution systems, regulated by the state Board of Public Utilities (NJBPU), and regional transmission firms were regulated by the FERC. Beginning in August 1999, customers in all classes had access to retail competition, and the legislation established a four-year transition time during which electricity prices were capped at 10% below the 1999 prices.

For the first decade of deregulation, New Jersey saw very little participation, or "switching," among residential or commercial customers. Initially, the price cap imposed by the EDECA did not provide much opportunity for new suppliers to make a profit, so there was little new offering of competitive prices. Even after the price cap was lifted, consumers were generally apathetic about switching and participation remained below 2% until about 2008. Recent declines in natural gas prices have brought additional providers offering lower prices into the market, and by July 2013 the number of customers that had switched service from their incumbent provider was approximately 17.5%.[2] This participation rate, however, is still well below rates in other deregulated states.

TIMELINE

1999—Electric deregulation law passed; retail access available to residential, commercial and industrial (C&I) customers

2003—Rate cap expires; minimal residential or commercial switching has occurred

2008—Natural gas prices begin to decline in late 2008, and forward electricity prices correspondingly drop

2010—Percentage of residential participation in alternative provider services increases from less than 1% to almost 10% with decline in market prices

2011—New Jersey Legislature passes Long-term Capacity Agreement Pilot Program (LCAPP) (P.L. 2011, Chapter 9), which promotes development of ~2,000 MW of new baseload or mid-merit generation facilities in New Jersey

2011—FERC approves PJM's proposed modifications to its Minimum Offer Price Rule, making the LCAPP more financially challenging

2012—Two of the proposed LCAPP generating facilities clear the PJM Base Residual Auction price, and one does not clear

2013—PJM's Markets and Reliability Committee abandons effort to add a long-term capacity auction or alternative multi-year mechanism to the revised PJM charter

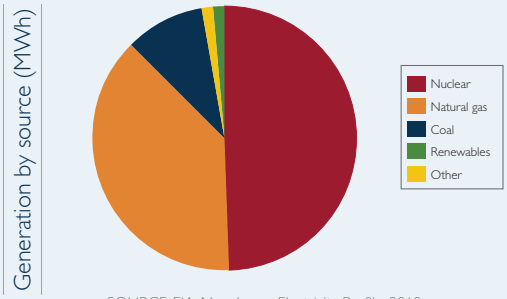
Market Share Served by Alternative Providers

18% of customers

44% of load (based on total MWh)

SOURCE: New Jersey Board of Public Utilities, *New Jersey Electric Switching Statistics*, July 2013.

- Deregulated in 1999
- Regional transmission organization (RTO)/ independent system operator (ISO): PJM
- Organized wholesale energy and capacity markets (PJM) under FERC jurisdiction
- Retail electricity sales (270 trillion BTUs): (#20 in nation)
- Average electricity price (cents/kWh in 2011): 14.3 (#6 in nation)



SOURCE: EIA, New Jersey Electricity Profile, 2010.

New Jersey, unlike Michigan, is fairly dependent on energy imports, with over 25% of its electricity bought on the wholesale market and transmitted to New Jersey from plants in other states.[3] This has influenced the success of deregulation, as discussed further below. New Jersey's in-state generation mix is largely made up of nuclear and natural gas, with a modest amount of coal, renewables, and other sources.[4]

New Jersey is a member of PJM, which is the RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. In order to assure that adequate generation capacity is available in the region to meet potential peak demand—that is, an adequate supply of electricity at all times—PJM established a "capacity market" and a capacity market pricing model in 2007 called the Reliability Pricing Model (RPM). According to PJM, its RPM capacity market is supposed to:

> *…create long-term price signals to attract needed investments in reliability in the PJM region…and stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity—resources that include not just generating plants, but demand response and transmission facilities.*[5]

Unhappy with the results of this capacity mechanism in terms of both its inability to stimulate new generation sources within the state and the price of electricity, the New Jersey legislature, with the support of Governor Chris Christie, enacted new legislation in 2011, the Long-term Capacity Agreement Pilot Program (LCAPP). This legislation represents a new form of state regulation and intervention designed to ensure adequate capacity generated by in-state facilities at acceptable prices.

The enactment of this legislation has sparked an ongoing battle between the State of New Jersey and the PJM, the FERC, and various out-of-state electricity providers that continues to this day both in federal court and at the FERC.

Issues

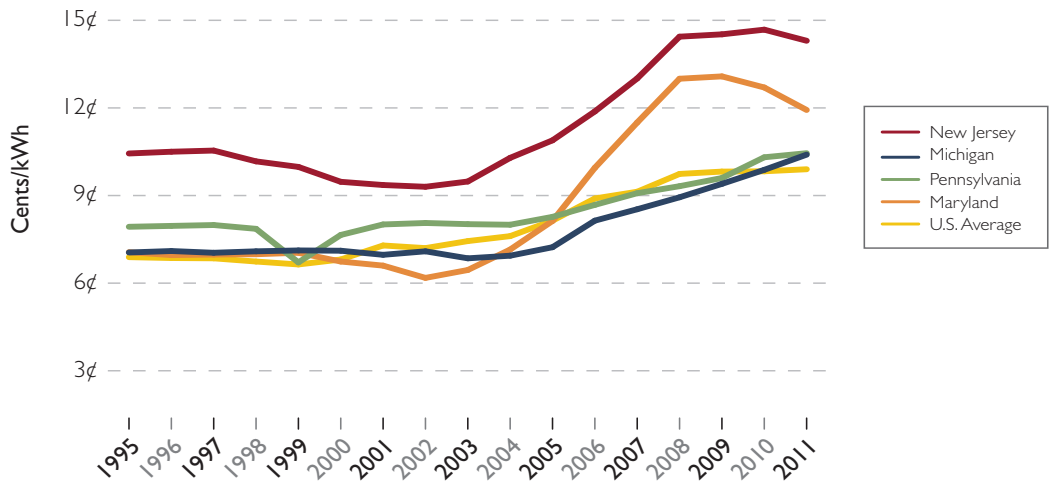
Affordability

New Jersey has historically had some of the highest electricity prices in the nation, consistently ranked 6th or 7th highest in the nation in the years just prior to deregulation. Lowering the cost of electricity was, in fact, one of the driving forces behind deregulation. Legislators and the Board of Public Utilities hoped that greater competition would drive down prices for New Jersey residents and businesses. When the EDECA passed the state legislature, electricity cost 9.98cents/kWh.[6]

Like other states that deregulated their electricity industry, New Jersey instituted a transition period during which electricity prices would be reduced and capped for a number of years in order to protect consumers from price increases while a new competitive market was developing. Although mandated price reductions or freezes obviously help consumers in the short term, they often deter new competitors from entering the market to compete with incumbents because there is not enough profit at the lower prices. In addition, dramatic price increases often occur once the caps are removed. This is precisely what occurred in New Jersey.

As the transition period ended in 2003, electricity prices in New Jersey began to climb again, going from 9.3 cents/kWh in 2002 to 14.3 cents/kWh in 2011—a 54% increase. New Jersey's electricity prices are highly correlated to natural gas prices, so the prices have dipped slightly during the last two years as natural gas prices have declined.[7] However, the state is still ranked 6th highest for electricity prices in the nation, and New Jersey electricity prices have been an average of 3.3 cents/kWh higher than the U.S. average price over the last 15 years.

New Jersey Prices Consistently Higher than Other States



SOURCE: EIA State Profiles and Energy Estimates database.

State Concern about the "Capacity Market" Pricing Model and Dependence on Out-of-State Electricity Imports

It has been the contention of the Christie administration and the NJBPU that PJM's capacity market and its RPM have not worked as intended or to the advantage of New Jersey because they have not resulted in new generation and keep New Jersey overly reliant on the transmission of expensive power from outside the state. Net electricity imports since 1999 have consistently been more than 20 million MWh/year, more than a quarter of its electricity use.

New Jersey contends that the capacity market is biased toward existing or expanding generators because it does not accommodate the need for long-term or multi-year price contracts. PJM allows capacity prices to be locked in for only one year, and therefore generators of new projects are unable to obtain financing at reasonable rates because of uncertain future revenue.[8] According to the state, this inhibits new generation in areas where it is most needed, such as in northern New Jersey where the grid is most congested.

New Jersey Electricity Imports
25% to 35%
over the last decade

New Jersey also points to the fact that clearing prices in the capacity market for New Jersey (and Maryland) are often quite a bit higher than those for unconstrained areas of PJM. For the 2016–2017 delivery year, for example, the clearing prices for the Public Service Electric and Gas (PSEG) Locational Deliverability Area (LDA), which covers New Jersey, rose 31% from the previous year, while all other PJM regions saw substantial decreases in prices (down 29% in the mid-Atlantic region and 68% in the northern Ohio area, for example). The New Jersey area was over $160/MW-day higher than the rest of the PJM area. PJM's summary of the 2016–2017 auction notes that the only LDA that saw price increases in the auction was PSEG, which has historically been transmission constrained. The PSEG area did not attract much of the new generation entry, and accounted for over half the electric generation facility deactivations since the last auction.[9]

A New Kind of State Regulation and Intervention Attempted

Dissatisfied with the results of deregulation and PJM's capacity pricing model in terms of reducing prices or stimulating new in-state capacity, the state created a new program, the LCAPP, which was designed to encourage new in-state generation. The LCAPP requires the state's regulated distribution-only utilities to enter into long-term contracts for new generation at a price that justifies the investment. The state issued a request for proposals to select generation projects and chose three gas-fired combined-cycle facilities that together would provide New Jersey with almost 2,000 MW of new capacity. The program allowed for contracts from the state that pay the new generators a subsidized minimum long-term price—one that is likely to be higher than the prices available on the PJM capacity market.

It is New Jersey's position that expanding in-state generation—by constructing or replacing power plants—would be cheaper and more reliable than depending on the PJM capacity pricing model and the transmission of electricity from western areas of PJM into New Jersey.[10] [11]

State vs. Federal Control of New Jersey Energy Policy

New Jersey policymakers want generation sources located in New Jersey for additional reasons beyond attempting to lower electricity prices. The state wants to meet its electricity needs with a more diverse and "clean" portfolio of energy sources than the predominantly coal-fired generation sources that are currently imported into the state through the PJM market. New Jersey has also cited the value of more than 2,400 temporary and about 80 permanent jobs that would be created by the construction of the new LCAPP-awarded generation facilities.

PJM and its network of incumbent generators have opposed New Jersey's efforts to encourage new in-state generation through LCAPP. They argue that New Jersey would, in effect, be subsidizing these facilities, therefore artificially depressing prices that would create an unfair economic advantage for them compared to others in the PJM region. Critics have also claimed that New Jersey is just using a work-around of the PJM system, leaving perceived deficiencies of the system in place. They have argued that New Jersey should instead be working with PJM to evaluate and modify the system as a whole to make it more effective. However, PJM's Markets and Reliability Committee recently abandoned efforts to add a long-term capacity auction or alternative multi-year mechanism to the revised PJM charter, leaving New Jersey's concerns about the RPM unaddressed.[12]

PJM has been successful in persuading the FERC to change various rules regarding minimum price offers, which have kept the LCAPP program from fully moving forward as planned.[13] At the same time, incumbent PJM generators have filed suit in federal

> *"New Jersey is opposed to a FERC-imposed paradigm that impedes in-state generation development while simultaneously imposing on our ratepayers an investment premium for transmission projects that import power from out-of-state generation sources far away from the state's loads."*
>
> —*State of New Jersey*

court challenging the constitutionality of LCAPP under the federal supremacy clause.[14] The FERC rule changes and federal court challenges have limited New Jersey's ability to feasibly pursue its own energy policies as represented by LCAPP.

Conclusion

New Jersey's experience with deregulation has undoubtedly not been what the state had either desired or anticipated. Price decreases—the primary reason for enacting the original legislation in 1999—have not materialized. New Jersey began its experiment with deregulation as the 6th highest priced state in the nation for electricity prices, and it is still the 6th highest priced state in the nation. The persistence of relatively high electricity prices led New Jersey to the conclusion that it would be better to rely on new in-state generation rather than the transmission of power from other areas of the PJM region. Because PJM's capacity markets and the associated pricing model have not resulted in the development of this in-state generation, however, the state attempted a new type of government intervention to control electricity prices and supply—the LCAPP. This state policy effort has, however, been successfully opposed by both the regional transmission organization and the federal government (FERC). It is also being contested in federal court by out-of-state energy providers that have an interest in continuing to export power to New Jersey. Because of PJM rule changes, the two LCAPP-funded power plants that have gone forward cleared the capacity market at a price well below their state-guaranteed rate, requiring the state to subsidize the difference. This will cost New Jersey taxpayers over $40 million in the first year.

What began as an attempt to reduce prices with deregulation has resulted in further government intervention and a struggle between the state and the federal government over control of state energy policy, without the desired price reductions.

Endnotes

1. State of New Jersey, December 6, 2011, *2011 New Jersey Energy Master Plan*. Available: http://nj.gov/emp/docs/pdf/2011_Final_Energy_Master_Plan.pdf (accessed 7-28-13).

2. New Jersey Board of Public Utilities, July 2013, *New Jersey Electric Switching Statistics*. Available: www.state.nj.us/bpu/pdf/energy/edc07.pdf (accessed 8-12-13).

3. While Michigan is not a net importer of electricity, it is almost completely reliant on imports of energy feedstocks to supply its electric generating facilities. In total, 82% of Michigan's natural gas and 100% of coal and nuclear fuel are imported from outside the state, accounting for about 72 cents of every dollar spent for energy by Michigan's residents and businesses. Michigan Public Service Commission, October 2011, *Michigan Energy Overview*. Available: www.dleg.state.mi.us/mpsc/reports/energy/energyoverview/ (accessed 8-12-13).

4. U.S. Energy Information Agency (EIA), July 2012, *New Jersey State Profile and Energy Estimates*. Available: www.eia.gov/state/?sid=NJ (accessed 7-25-13).

5. PJM, Reliability Pricing Model website. Available: www.pjm.com/markets-and-operations/rpm.aspx (accessed 9-8-13).

6. The EIA tracks electric prices in all U.S states. Electricity prices noted in this paper are the EIA's average of residential, commercial, and industrial prices.

7. EIA, *New Jersey State Profile*.

8. State of New Jersey, *Energy Master Plan*.

9. PJM, N.d., *2016/2017 RPM Base Residual Auction Results* (PJM Docs #753726), p. 31. Available: www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx (accessed 8-18-13).

10. State of New Jersey, *Energy Master Plan*.

11. Tom Johnson, June 18, 2013, Assembly Panel Faults BPU for Failure of Deregulation, *NJSpotlight*. Available: www.njspotlight.com/stories/13/06/17/assembly-panel-faults-bpu-for-failure-of-deregulation/ (accessed 7-29-13).

12. "PJM Abandons Long-Term Capacity Effort," August 6, 2013, *RTO Insider*™, Available: www.pjminsider.com/long-term-capacity-1/ (accessed 8-21-13).

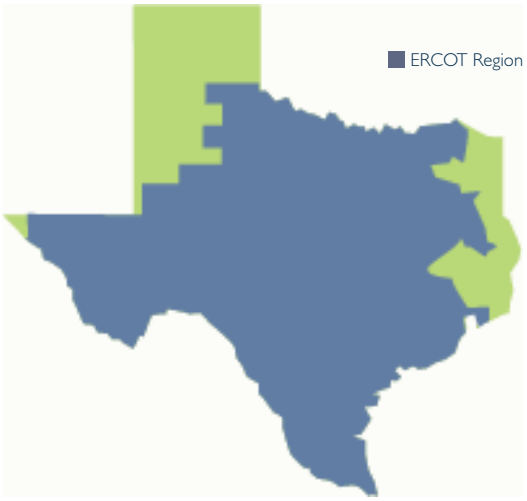
13. Three developers were selected under the LCAPP pilot program to provide new generation facilities: NRG, Hess Corporation, and Competitive Power Ventures (CPV). CPV and Hess cleared the capacity auction in May 2012, and both are under construction, but NRG has not cleared the last two auctions and that facility's future development is in question.

14. Roger Stark and Daniel Simon, January 1, 2012, Traps for Unwary Project Sponsors—the LCAPP Saga, *Electric Light and Power* (Jan/Feb 2012). Available: www.elp.com/articles/2012/01/traps-for-unwary-project-sponsors-the-lcapp-saga.html (accessed 7-28-13).

Rates have been higher and more volatile in the deregulated areas of Texas. But the state's more serious challenges relate to reliability and the adequacy of power supplies.

Summary

Texas is an important state to examine in the context of state deregulation of electricity markets, for a number of reasons. First, it was one of the earliest states to follow California in deregulating its electric industry—it began the effort in 1999 with the enactment of legislation for retail competition, and began full deregulation in 2002. Second, unlike a number of other states that began the process of deregulation but reversed course as they encountered problems, Texas has not abandoned deregulation. In fact, the organization that ranks and rates the various states on the degree of "competition" and "deregulation" rates Texas as the "competitive electricity market leader."[1] Third, although Texas is often classified as a "fully deregulated state," parts of Texas continue to operate under a fully regulated market structure, allowing for comparisons within the state of the impacts of deregulation and continued traditional regulation. Fourth, Texas is the only state in the nation that has jurisdiction over both the wholesale and retail electricity markets. All other states are limited to regulation over retail markets while the federal government—through the Federal Energy Regulatory Commission (FERC)—maintains regulatory authority over the wholesale market. Finally, Texas illustrates some of the key challenges that can plague deregulated electricity markets: reliability, affordability, and a number of unintended—and unanticipated—consequences.



History and Profile

Texas followed California and several other states in deregulating its electric industry. The state began this effort in 1995 by allowing generators open access in the wholesale market. Texas passed legislation for retail competition in 1999 and moved aggressively to introduce full deregulation on January 1, 2002. The transition continues to be a complex and lengthy process, with challenges to reliability and affordability.[2]

Texas's electric industry and regulatory framework are unique. It has limited electrical interconnection to other states and, therefore, the Public Utility Commission of Texas (PUC)—rather than the Federal Energy Regulatory Commission—has jurisdiction over electric transmission rates and the wholesale electric market within the Electric Reliability Council of Texas (ERCOT) region. Thus, the PUC oversees both the retail and wholesale markets within ERCOT, providing oversight over all aspects of the industry, including long-term reliability and retail and wholesale market operations. This avoids some of the challenges experienced in other states and the portion of Texas outside of ERCOT (East Texas, Panhandle, and El Paso region) that have overlapping state and federal jurisdiction related to electric deregulation.[3] The ERCOT region covers about 75% of the state's land area. Approximately 64% of the state's electric load (the majority of ERCOT) is under deregulation.

Texas relies on natural gas for the generation of electricity more than most other states, and this has influenced its wholesale and retail market design and performance under deregulation, as discussed further below.

TIMELINE

1995/1996—Wholesale competition introduced and ERCOT begins operations as independent system operator

1999—Deregulation law enacted; retail utility rates frozen as part of transition

2001—Retail access pilot; significant IT challenges for wholesale and retail billing

2002—Deregulation begins in ERCOT

2004—Stranded cost "true-up" proceedings

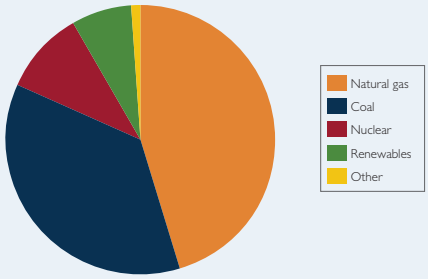
2006—Prices in deregulated areas peak, 62–88% higher than 2002 prices (compared to increase of only 24% in regulated areas during this time frame)

2011—ERCOT acknowledges reserve levels below target; experiences supply emergency during record-setting weather and peak demand in August; preceded by rolling power outages in February 2011 due in part to cold snap and unplanned generation outages

2012—The Brattle Group releases report for ERCOT on investment climate for new generation and options to address looming power shortages

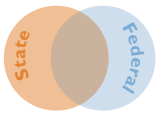
2013—North American Electric Reliability Corporation (NERC) issues warning letter to ERCOT regarding reliability concerns due to low generation reserves

Generation by source (MWh)



SOURCE: Public Sector Consultants, based on data from Energy Information Administration (EIA): www.eia.gov/electricity/state/Texas/. Average electricity price is for the entire state, including both deregulated and regulated areas.

- Deregulated in 2002 within ERCOT (except municipally owned and electric cooperatives that do not opt in); remains regulated outside ERCOT
- Regional transmission organization (RTO)/independent system operator (ISO): ERCOT
- "Energy-only" wholesale market (no capacity market)
- Electricity sales (MWhs): 358,457,550 (#1 in nation)
- Average electricity price (cents/kWh in 2010): 9.34 (#21 in nation)

	California Experience	**Texas Response**
 Surge in wholesale power prices with capped retail rates	Cap on retail rates resulted in wholesale prices exceeding retail prices and related problems, including financial distress for power providers and subsequent price spikes.	Rates for the default service charged by incumbents can fluctuate based on market conditions in order to keep incumbents solvent and attract and retain alternative suppliers.
 Power shortages/ rolling blackouts	Regulatory restrictions and market conditions dampened new power plant investment. Weather and environmental restrictions limited access to hydro-electric generation supplies in Pacific Northwest, contributing to California's power shortages.	Texas had significant excess generation capacity and market conditions to support new generation. Texas not dependent on significant quantities of hydro-electric generation.
 Overlapping federal and state jurisdiction	Claims that federal government did not intervene soon enough to prevent or mitigate market abuses by unregulated power generators such as Enron. Poorly designed wholesale market allowed manipulation and excessive prices.	Texas—not the federal government—can protect consumers from market manipulation by suppliers and properly designed market rules and state oversight can insure stable prices.

Texas deregulated the electric industry within the ERCOT region on the heels of the California meltdown in 2000 and 2001. Policy leaders in Texas emphasized how the state's situation was dramatically different from California, as highlighted above.

Indeed, Texas has been rated as the "competitive electricity market leader" for both residential and commercial markets in the *Annual Baseline Assessment of Choice in Canada and the United States* (ABACCUS) for numerous years, primarily because of customer "switching" rates and the number of alternative providers.

It is noteworthy that Texas has sustained this level of participation over time. Texas avoided some of the problems experienced in other states but has had its own share of challenges with reliability and affordability of electric service. The state continues to face problems, particularly related to the adequacy of power supplies.

Market Share Served by Alternative Providers

61%
of customers
(60% residential only)

76%
of load (MWh)

SOURCE: Public Utility Commission of Texas, 2013, Summary of Performance Measure Data (Non-Confidential Version). Available at: www.puc.texas.gov/industry/electric/reports/RptCard/Default.aspx (accessed 6-3-13.) Note that some of the "alternative providers" are the predecessors of the incumbent utilities serving other parts of the state. Percentages apply to deregulated areas of Texas as of December 2012.

Issues

Reliability

Proponents of deregulation suggest that generation will be built where and when it is needed under deregulation. Not only has this not occurred in Texas, but the opposite has happened—that is, investment has actually declined as documented need has increased. State officials touted Texas's very high reserve margins prior to deregulation, and the state is now faced with significant reliability challenges due to generation reserve shortages.

> *"The electricity utility industry employs a simple strategy for maintaining reliability: always have more supply available than may be required."*
>
> —Energy Information Administration (EIA)

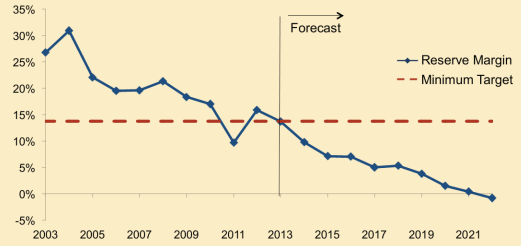
As with other areas of the country, Texas experienced a wave of new investment in the early 2000s, primarily natural gas plants. Investment losses followed, leaving investors more cautious and demanding more assurance that there will be stable revenues resulting from any new investments.[4] Meanwhile, population continued to grow steadily, with overall energy use and demand for electricity increasing about 2% annually on average in recent years. Extreme weather conditions in 2011 led to increased consumption and record-breaking peak demand that stressed the system. By the end of 2011, ERCOT reports revealed that development of new generation was not keeping pace with the need.[5] Investment had stalled despite reserve margins falling below target levels due to plant retirements and load growth.[6] A total of 15,223 MW of generation has been retired or mothballed since 1995 in ERCOT.[7] NERC, which is accountable for assessing the current and future reliability of the bulk-power system, issued a January 2013 warning letter to ERCOT, stating:

> *Capacity resources in ERCOT have* ***drifted to a level below the Planning Reserve Margin target*** *and are projected to* ***further diminish*** *through the ten-year period covered in the [reliability] assessment. It is clear to me that these levels imply higher* ***reliability risks*** *especially the potential for firm load shed, and ERCOT will need more resources as early as summer 2013 in order to maintain a sufficient reserve margin…* ***These concerns are not new****, as NERC has raised this issue in prior assessments.*[8] *(emphasis added)*

ERCOT has acknowledged that there is a significant chance that it will need to declare an energy emergency alert in the near future. And if there are higher-than-normal power plant outages during a period of high demand or weather similar to 2011's heat wave, ERCOT expects that "rotating outages could become necessary to maintain the integrity of the system."[9] Faced with these challenges, ERCOT commissioned a study by a well-known national energy consulting firm, the Brattle Group, to analyze the reliability issues and the market's ability to attract investment in new generation. In its June 2012 report, the Brattle Group found that reserves are projected to fall to 9.8% by 2014, substantially below the current 13.75% reliability target.[10] It further concludes:

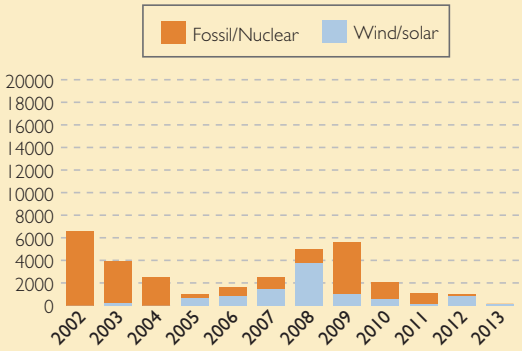
> *The year 2014 poses a particular challenge because it may be approaching too quickly to add some types of new capacity, even if market conditions would support such investments.*[11]

Dwindling Generation Reserves Put Reliability at Risk



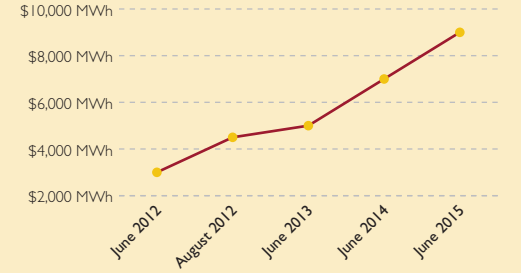
SOURCE: DTE Energy, March 25, 2013, Presentation at Detroit Forum for Readying Michigan to Make Good Energy Decisions, hosted by the MPSC and Michigan Energy Office, based on data from NERC (2012 Long-term Reliability Assessment) and Ventyx Velocity Suites – ERCOT.

Power Plant Investments Don't Keep Pace



SOURCE: PUCT, New Electric Generating Plants Since 1995 (excluding renewable), as of 1-23-13, www.puc.texas.gov/industry/maps/elecmaps/gentable.pdf (accessed 7-3-13).

Increasing Wholesale Price Caps



SOURCE: ERCOT, December 2012, Striking a Reliable Balance: 2012 State of the Grid Report, p. 9, www.ercot.com/content/news/presentations/2013/2012%20ERCOT%20State%20of%20the%20Grid_Web.pdf (accessed 7-3-13).

Faced with these challenges, the PUC responded, in part, by raising the cap on wholesale power prices–eventually to $9,000 per MWh, or roughly 300 times the average wholesale electricity price.[12] Generally, customers would not see this price directly, as prices would not reach that level except during extreme events and the rates actually charged to customers would level out these prices with lower prices during more normal conditions. Raising the cap allows wholesale prices to reach extremely high levels when supplies are tightest and should provide greater incentive for new investment given the shortages experienced and projected in Texas. However, prices would need to be sustained at extremely high levels with enough frequency to attract enough investment, and the greater the frequency, the greater the impact on prices. The Brattle Group concluded that **even with a $9,000 cap, a reserve margin of only 10% could be reached—far below the reliability target.**[13] NERC also points out the limitations of this partial solution in addressing the overall reliability concerns. And industrial customers in Texas—while supportive of efforts to ensure reliable power—cautioned that the increased cap could cost the state an additional $14 billion annually.[14]

Texas's challenges in the area of reliability are compounded by the mix of its generation. Low natural gas prices and new wind generation have led to lower margins for generators (which in turn lead to inadequate incentives to build new supply). The president of NRG Energy, the second largest generator in Texas, recently stated:

> *[T]here is little incentive for investors to build new, billion-dollar power plants because the price of electricity is so low. The cost of natural gas, among other factors, has driven energy prices down—good for consumers in the short term, but dangerous to long-term reliability because demand for power is growing faster than new generation is being built.*[15]

The market is responding to price signals—exactly what the proponents of deregulation want—and the signals are telling investors not to build new capacity. Ironically, even though demand for electricity is starting to outstrip supplies, it is difficult for merchant generators and the market as a whole to adapt to these market conditions and ensure that the right kind of generation is built at the right time. Unlike a regulated utility, investors are not looking at long-range needs to develop a balanced mix of generation based on cost, reliability, and supply diversity. Demand response does play an important role in Texas, but it does not obviate the need for additional supply-side resources.

Despite warning signs over several years and an urgent need for additional power sources to maintain reliability, there has not been the necessary investment. The PUC and ERCOT are considering whether additional interventions are necessary. Numerous entities, from generators to NERC to energy experts, have suggested that additional intervention beyond the increased price cap already adopted is needed to ensure adequate power supplies. One option

> *"The Texas economy is stronger than any other state's. We don't want to mess this up by creating conditions that lead businesses to believe Texas has an unreliable electric state."*
>
> —John Ragan, *Houston Chronicle* editorial, 6-11-13

that is under consideration is a capacity market similar to those in place in the Northeast. This would provide a mandated capacity payment to generation owners for being available in future years. This payment would be in addition to the payments to generators for the actual production of electricity and thereby provide a more stable revenue stream and incentive to build new generation. But like the increase in the price cap, capacity markets are expected to raise electricity costs overall. In an editorial advocating for a capacity market, NRG's president emphasizes the cost of inaction to the state's economy:

> *In years past, Texas had a healthy reserve, meaning that rolling blackouts and outages have largely been avoided with the exception of a couple of freak occurrences. But our reserve margin is shrinking each year and we have recently seen repeated calls for emergency conservation. If we do that again—or, worse, if the lights go out—businesses that recently moved here, employ our citizens, and invest in Texas will begin to question that decision and they, as well as businesses contemplating moving here, may look to other states where power is more reliable.*[16]

Capacity markets have been used in other regions, although there have been challenges in the design and implementation of capacity markets and their effectiveness in actually spurring new investment remains in question. To date, Texas has rejected this form of market intervention to address its reliability challenges in part because many consider it a violation of "free market" principles—i.e., a government mandate that results in price increases.

Affordability

States that deregulated faced the need to protect consumers yet "create a market" during the time of transition. Many states put in place rate freezes or reductions for residential and small business customers during the transition period. While the capped rates may have protected such consumers in the short term, they often undermined the ability to attract and retain new providers to compete with the incumbent (because the capped rates were below market at times due to fluctuating fuel and wholesale power prices). Texas did a better job of balancing these two objectives to encourage new entrants and protect customers.

Texas required that electricity providers affiliated with the incumbent utility charge a "price to beat" until the incumbent lost

sufficient market share to alternative providers. This price was designed as a price floor and ceiling. In other words, it was designed to prevent the incumbent from offering artificially low rates to stifle competition and undercut new market players. It was also intended to provide a cap, or ceiling, so that customers that didn't switch providers still received some benefit. When the price to beat was set, it included a 6% discount off the utility's base rates. (Rates were frozen as part of the restructuring law in 1999 and were expected to be reduced during this time period had regulation continued.)

Despite the 6% reduction, the fuel portion of the rate was indexed to natural gas prices, which fluctuated based on the market. This avoided some of the challenges that occurred in other deregulated states where the overall default rates were fixed, leading to significant unrecovered costs that were deferred and eventually caused large price spikes when the price caps expired. But Texans faced a different challenge—prices in the deregulated areas steadily climbed as natural gas prices rose in the mid-2000s. From 2002 to 2006, the price to beat rose 88% and the competitive offers rose 62%. In contrast, rates in regulated areas of Texas rose only 24% during this period. For over a decade, deregulated areas of Texas have consistently paid more for electricity than regulated areas of the state. And prices are more volatile in deregulated areas.

> *"With declining costs and the strong load growth in the State, it is likely that the commission could find itself facing a never-ending stream of rate cases in an attempt to harness utility over-earnings."*[17]
>
> —Public Utility Commission of Texas

This volatility is a function of deregulation. Regulated utilities pass through fuel costs without a markup. This includes the utility's actual costs based on its fleet of power plants (typically a mix of nuclear, coal, and natural gas). Although these costs and the amounts charged to customers can fluctuate over time as fuel costs change, the impact on customers is tempered because of the diversity in the fuel mix. In contrast, electricity prices in the deregulated areas are heavily dependent on the price of natural gas, which is often the marginal fuel used for electricity generation. Given the historic volatility of natural gas prices, this creates vulnerability for customers. Regulated areas have proven to be more adaptable to market fluctuations. Commercial and industrial rates in Texas have also been volatile, particularly under deregulation.

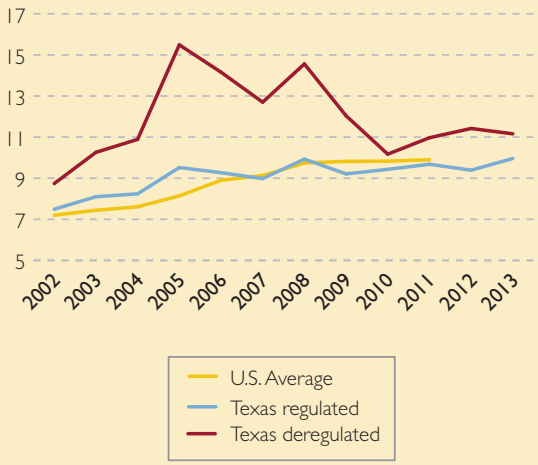
It was envisioned that deregulation would lower prices, but the data suggest the contrary occurred in Texas—prices in deregulated areas have been higher and more volatile than in regulated areas of the state.

Unintended Consequences

Texas policymakers crafted a comprehensive law to deregulate the electric industry with the goal of increasing competition and providing associated savings to customers. As the law was implemented, however, the state faced numerous unintended consequences, which illustrate the complexities and inherent uncertainties involved with deregulation. For example:

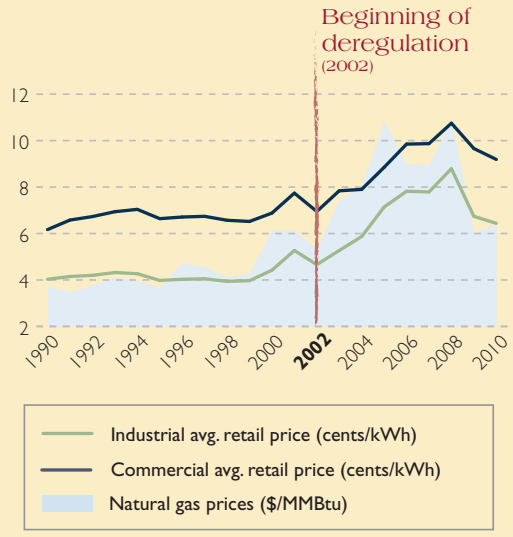
- IT struggles—Texas experienced major problems with billing and IT systems at the advent of the deregulation, which proved costly for customers and

Residential Rates
Texas vs U.S. Average



SOURCE: Public Sector Consultants, using data from Energy Information Administration and the Public Utility Commission of Texas.

C&I Electricity Prices vs. Natural Gas Prices
Texas 1990–2010



SOURCE: Public Sector Consultants, using data from Energy Information Administration and the Public Utility Commission of Texas.

providers.

- Provider of last resort—The state also faced major challenges setting up the "provider of last resort," or POLR, in deregulated areas because providers were unwilling to bid on such service as laid out in the law.
- Costly market redesign—There were also issues with market manipulation at times and a costly redesign of the wholesale market.
- Stranded costs—A major unintended consequence that will have a lasting impact on customers relates to stranded cost recovery. The Texas deregulation law allowed utilities to recover their stranded costs, or the difference between the market value and the book value of generation assets.

Estimates of stranded costs were calculated at various points during the transition to deregulation in order to provide for early mitigation and recovery, as applicable. Due to fluctuating market conditions over time and regulatory decisions, estimates of stranded costs ranged from negative $2 billion (during periods of high natural gas prices making higher-cost plants more economical) to over $6.5 billion. By the time the issue was fully litigated, the total amount customers will pay amounted to over **$9.5 billion**.[18] Even though customers are on the hook for this amount, private equity investors resold the assets at a significant profit under better market conditions. While the state's policy was well intended, it did not adequately anticipate the rapidly changing market conditions. This experience has been costly for businesses and residents of Texas, and underscores the complexities and trade-offs of deregulation.

Conclusion

Texas has been successful in attracting and retaining alternative suppliers. The rates charged by the default provider during the transition to deregulation were allowed to fluctuate based on natural gas prices. Texas's approach avoided the situation other states experienced with wholesale prices exceeding capped retail rates, resulting in price spikes after the caps expired (due to the collection of deferred costs) and/or bankruptcies or other financial distress in the industry. The rates in Texas were also sufficiently high to allow new providers to enter the market and serve customers, including residential. Deregulation did not, however, bring about lower rates as initially envisioned. In fact, rates have been higher and more volatile in the deregulated areas of Texas. The state's more serious challenges relate to reliability and the adequacy of power supplies. The reliance on market forces to incent the right mix of investments has not resulted in investments necessary to ensure an adequate supply of electricity to residents and businesses in Texas.

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6. Brattle Group, p. 1.

7. Public Utility Commission of Texas (PUCT) data. Available: www.puc.texas.gov/industry/maps/elecmaps/gentable.pdf (accessed 6-3-13).

8. Letter from Gerry Cauley, President and CEO, North American Electric Reliability Corporation, to Trip Doggett, ERCOT President and CEO, January 7, 2013. Available: www.ercot.org/content/news/presentations/2013/NERCletterto TripDoggettonResourceAdequacyJan72013.pdf (accessed 6-3-2013).

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10. Brattle Group, p. 1. The Brattle Group has a more conservative target of 15.25% because it accounts for 2011 weather.

11. Brattle Group, p. 6.

12. Based on ERCOT North region average bilateral prices for 2012. See Federal Energy Regulatory Commission, January 2013, *Texas Annual Average Bilateral Power Prices*. Available: http://ferc.gov/market-oversight/mkt-electric/texas/elec-tx-yr-pr.pdf (accessed 6-3-13).

13. Brattle Group, p. 3.

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16. Ibid.

17. Public Utility Commission of Texas (PUC), January 1999, *Report to the 76th Texas Legislature: The Scope of Competition in the Electric Industry in Texas*. Available: www.puc.texas.gov/industry/electric/reports/scope/1999/1999scope_elec.pdf (accessed 7-3-13).

18. See: Public Utility Commission of Texas, January 2001, *Report on the Scope of Competition in Electric Markets*, available: www.puc.texas.gov (accessed 6-3-13); Texas Senate Committee on Business and Commerce, December 1, 2004, *Electric Utility Restructuring and Renewables: Interim Report to the 79th Texas Legislature*, available: www.senate.state.tx.us/75r/Senate/commit/c510/Downloads/EURRCh56.pdf (accessed 6-3-13). See also securitization orders in PUC Docket nos. 21665, 21528, 25230, 30485, 32475, 34448, 39809, and 39931, available: http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/login/pgLogin.asp (accessed 7-3-13). The current value of $9.5 B includes all amounts securitized including the amount authorized in TXU Electric (now Oncor) settlement. TNMP's stranded costs, which were not securitized, are also included.

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